The Role of E-fuels in Decarbonising Transport

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Abstract

Rapid deployment of low-emission fuels during this decade will be crucial to accelerate the decarbonisation of the transport sector. Significant electrification opportunities are available for the road transport sector, while the aviation and marine sectors continue to be more reliant on fuel-based solutions for their decarbonisation.

Fuels obtained from electrolytic hydrogen, or e-fuels, could be a viable pathway and scale up quickly by 2030, underpinned by a massive expansion of cheaper renewable electricity and anticipated cost reductions of electrolysers. Low-emission e-fuels can add to the diversification of decarbonisation options that are available for aviation and shipping and there exists a big potential synergy with biofuels production, especially in the form of biogenic CO_2 utilisation.

This new IEA report presents a techno-economic assessment of a family of emerging e-fuel technologies. It assesses the implications in terms of needed cost reductions, resources and infrastructure investments of an assumed ambitious goal of achieving a 10% share of e-fuels in aviation and shipping by 2030.

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Executive summary

Rapid deployment of low-emission fuels during this decade will be crucial to accelerate the decarbonisation of the transport sector. Significant reductions in fossil fuel demand are possible in road transport through fuel efficiency improvements and surging sales of electric vehicles (EVs). At the same time, the aviation and marine sectors continue to be more reliant on fuel-based solutions for their decarbonisation. Sustainable aviation fuels are increasingly becoming part of the aviation fuel mix, while orders for new ships are showing a trend towards alternative fuels.

Fuels obtained from electrolytic hydrogen, or e-fuels, could be a viable pathway and scale up rapidly by 2030, underpinned by a massive expansion of cheaper renewable electricity and anticipated cost reductions of electrolysers. This study is not a scenario analysis, but a techno-economic assessment of a family of emerging e-fuel technologies. It assesses the implications in terms of needed cost reductions, resources and infrastructure investments of an assumed ambitious goal of achieving a 10% share of e-fuels in aviation and shipping by 2030.

Low-emission e-fuels can add to the diversification of decarbonisation options that are available for transport. E-fuels are low-emission fuels when their hydrogen is produced using low-emission electricity and any carbon inputs are obtained in a way that leads to low life-cycle greenhouse gas emissions. In transport, low-emission e-fuels provide a complementary solution to sustainable biofuels. Particularly in aviation, e-fuels benefit from their ability to use existing transport, storage, distribution infrastructure and end-use equipment.

Low-emission e-fuels are currently expensive to produce, but their cost gap with fossil fuels could be significantly reduced by 2030. By the end of the decade, driven by cost reductions enabled by the realisation of current globally announced electrolyser projects, tapping sites with high-quality renewable resources and optimised project design, the cost of low-emission e-kerosene could be reduced to USD 50/GJ (USD 2 150/t), which would enable it to compete with biomass-based sustainable aviation fuels. The cost of low-emission e-methanol could be cut to USD 35/GJ (USD 700/t) and e-ammonia to USD 30/GJ (USD 550/t) making them cost comparable with the higher end of fossil methanol and ammonia prices over the 2010-2020 period as a chemical commodity, and opening a door for their use as a low-emission fuels for shipping. Moreover, the production of e-fuels for aviation also leads to non-negligible amount of e-gasoline being produced as a by-product.

Low-emission e-fuels, while still costly in 2030, will have limited impact on transport prices at a 10% share. At a cost of USD 50/GJ, e-kerosene would increase the ticket price of a flight using 10% of e-fuels by just 5%. Although e-methanol and e-ammonia are cheaper to produce than e-kerosene, their widespread use as shipping fuels will require significant investments in compatible bunkering infrastructure and ships. The total cost of ownership of a 100% e-ammonia or e-methanol-fuelled containership would be 75% higher than a conventional containership operating on fossil fuels. Although a substantial increase, the extra cost would represent only 1-2% of the typical value of goods transported in containers.

Due to several conversion steps and associated losses, the production of e-fuels generally suffers from low efficiency, leading to high resource and/or infrastructure demand. Producing large amounts of low-emission e-fuels could trigger around 2 000 TWh/yr of additional renewable electricity demand by 2030. While a significant increase, that would be around one-fifth of the growth of low-emission electricity during this decade in the IEA's Stated Policies Scenario (STEPS), and less in the Announced Pledges Scenario (APS) and Net Zero Emissions by 2050 Scenario (NZE Scenario). The production of low-emission e-fuels can also unlock the huge potential of remote locations with high-quality renewable resources and vast amounts of land available for large-scale project development, which would not otherwise have high electricity demand. By contrast, a significant ramp up of electrolyser manufacturing would be needed to achieve a 10% share of e-fuels in both aviation and shipping since it would require over 400 GW of electrolyser capacity, equal to the entire size of the global electrolyser project pipeline to 2030.

Accelerated deployment of low-emission e-fuels for shipping would require significant investments in refuelling infrastructure and in vessels. Achieving a 10% share in shipping would require around 70 Mt/yr of e-ammonia or e-methanol. This is 3.5 times the current global traded volume of ammonia or two times the trade in methanol. Additional cumulative investments in shipping capacity would be USD 30-75 billion, dependent on how investments would be distributed between ammonia and methanol ships. This would represent less than a 5% share of the cumulative shipbuilding market size over the period of 2023-2030. Similarly, the incremental investment for bunkering infrastructure is expected to be in the order of USD 10-30 billion.

Carbon-containing low-emission e-kerosene and e-methanol would require a massive increase in CO_2 utilisation. There exists a significant potential synergy with biofuels production, as by-product CO_2 from bioethanol and from biomethane plants are among the cheapest (USD 20-30/t CO_2) sources. Moreover, coming from sustainable biogenic sources, they enable the production of low life-cycle GHG emission e-fuels.

Around 200 Mt CO_2 would be needed to produce the 10% share of e-kerosene for aviation, and 150 Mt CO_2 to produce the 10% share for shipping if all would be in the form of e-methanol. It would not be possible to supply this combined amount from low-cost biogenic sources alone, but it could be supplemented from pulp making, albeit at a higher cost. In any case, utilising this currently untapped resource would require massive scale up of over 100 times the current capture volumes from biogenic sources.

Access to CO_2 is an important constraint to carbon-containing low-emission e-fuels, which is not the case with e-ammonia. The best wind and solar resources are not necessarily co-located with significant bioenergy resources, which puts additional constraints on siting e-fuel projects that require carbon input. This may require CO_2 pipeline infrastructure. While techno-economically feasible, it may face important social acceptance challenges.

Direct air capture (DAC) of CO_2 could provide a potentially unlimited source of CO_2 feedstock without geographic constraints, but it is expected to remain a high-cost option in 2030. By contrast, as a carbon-free molecule, ammonia production does not require CO_2, therefore has less constraints for project development.

To enable widespread adoption and trade, e-fuels will need to meet established technical and safety standards and internationally agreed methodologies for measuring life-cycle GHG emissions. International bodies such as International Organization for Standardization (ISO), the International Maritime Organization (IMO) and the American Society for Testing and Materials (ASTM) have already established standards for some e-fuel production and use pathways, but standards for ammonia quality and safety, methanol safety, and higher e-kerosene blending levels are still under development. Further development of comprehensive international standards, protocols and pathways for fuel quality, safety and life-cycle GHG emissions are needed to enable trade and use in international aviation and shipping. These processes will also require ongoing development as new technologies and applications for e-fuels evolve.

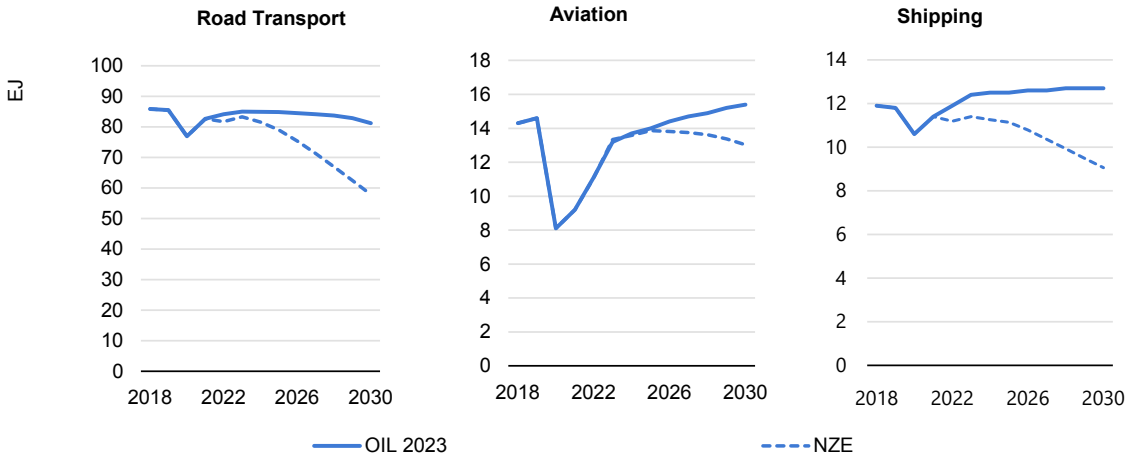
Governments need to take bolder action to stimulate demand for low-emission e-fuels. In order to exploit potential decarbonisation options, with limited increase on consumer prices, achieving economies of scale through predictable demand will be key. More than 200 projects are currently under development around the world, although a large majority of e-fuel projects are at early stages. To achieve accelerated deployment, it is essential that countries continue to adopt policies that create a predictable demand for early projects, support required infrastructure investments, drive down the cost of electrolysers, encourage R&D activities focused on developing new high-efficiency e-fuel technologies, and promote the potential to exploit synergies between e-fuels, biofuels and carbon capture utilisation and storage (CCUS).

Chapter 1. Introduction

The global energy crisis has moved energy security to the fore of the international policy agenda and accelerated the momentum behind the deployment of clean energy technologies. Government policy makers prioritising energy security are increasingly focused on the role that fuels obtained from electrolytic hydrogen, or e-fuels, can play in reducing oil dependence and decarbonising the transport sector. E-fuels are low-emission fuels when their hydrogen is produced using low-emission electricity and any carbon inputs are obtained in a way that leads to low life-cycle greenhouse gas emissions. E-fuels made from biogenic or air-captured CO_2 can potentially provide full emissions reduction, making them the primary production pathway that is consistent with achieving net zero emissions by mid-century.

Investment in clean energy is already accelerating at a much faster rate than for fossil fuels, helping to deliver a peak in global fossil fuel use before 2030. From 2017 to 2023, clean energy investments increased from around USD 1.13 trillion to USD 1.74 trillion. At the same time, spending on fossil fuels declined from USD 1.11 trillion to USD 1.05 trillion. However, the pace of change is still too slow, and stronger policy measures and behavioural changes will be needed to get on track with the NZE Scenario.

Figure 1.1 Transport sector oil demand under current policies and net zero targets



Notes: Oil 2023 = data from the IEA's Oil 2023 - Analysis and forecast to 2028. NZE = Net Zero Emissions by 2050 Scenario.

In road transport, vehicle efficiency improvements – along with surging sales of hybrid and electric vehicles – are driving down average fuel consumption and CO_2

emissions. As a result, gasoline and diesel use by cars, vans, trucks and buses is set to peak this decade despite the projected surge in the number of vehicles on the roads by 2030, especially in emerging and developing countries. At the same time, aviation demand is set to nearly double from 3.5 trillion passenger kilometres (pkm) in 2022 to 6.7 trillion pkm in 2030 (9% CAGR). Shipping demand similarly rises from 124 trillion tonne kilometres (tkm) to 145 trillion tkm (2% CAGR) over the same period, according to the IEA's recently updated Net Zero Roadmap.

Against the backdrop of increasing transport demand, sustainable fuels will play a critical role in decarbonising the aviation and shipping sectors. Even as batteries and electric motors become viable in aviation and maritime applications, they are likely to be limited to smaller aircraft and vessels with shorter transit ranges, given limitations in battery energy and power density. Sustainable aviation fuels are increasingly becoming part of the aviation fuel mix, while orders for new ships are showing a trend towards alternative fuels.

When e-kerosene is produced to complement sustainable biofuels in aviation, a non-negligible amount of e-gasoline is produced as a by-product. It could be blended into the motor gasoline pool or used for petrochemicals. The production of e-diesel is also possible. The drop-in nature of some e-fuels means that, alongside biofuels, they could help reduce emissions from the current vehicle stock and speed up the decarbonisation of road transport with only limited or no investments in distribution and end-use infrastructure. It could also help alleviate concerns over the security of supply of critical minerals needed for battery manufacturing.

Despite limited deployment today, the number of announced low-emission e-fuels projects is increasing at a rapid rate. More than 200 projects are currently under development around the world, but the majority of them are still in early stages. The slow uptake of low-emission e-fuels is a consequence of a wide cost gap with incumbent fossil fuels and other already commercially available low-emission alternatives, such as biofuels. If low-emission e-fuels are to make a meaningful contribution to emissions reductions in energy transitions, a rapid scale up is needed during this decade.

This study is not a scenario analysis, but a techno-economic assessment of a family of emerging e-fuel technologies. It assesses the implications in terms of needed cost reductions, resources and infrastructure investments of an assumed ambitious goal of achieving a 10% share of e-fuels in aviation and shipping by 2030.

Chapter 2 provides an overview of the demand trends in transport and discusses the supply potential of biofuels. Chapter 3 reviews the current status of e-fuel technologies and provides an outlook to 2030 based on announced projects. It also reviews the policy environment relevant for low-emission e-fuels

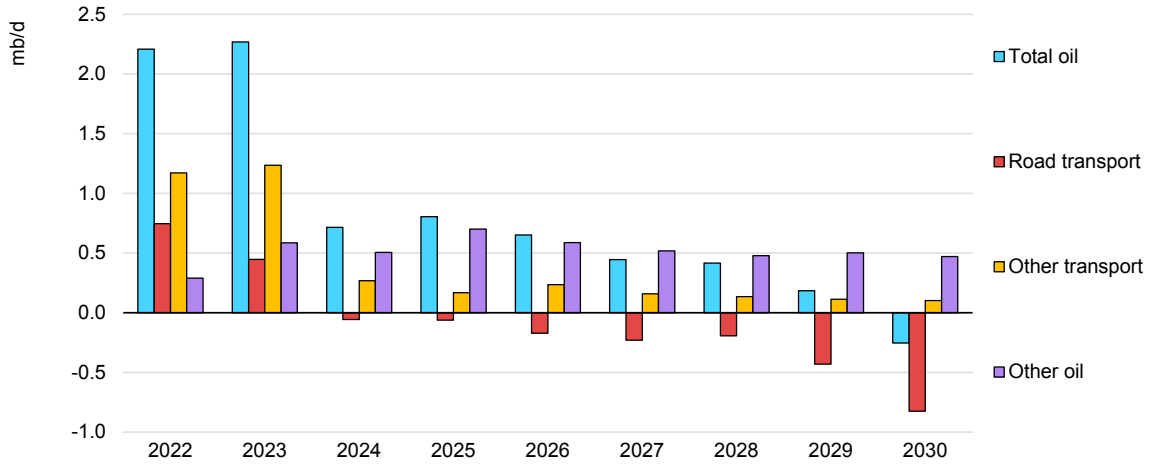
development. With the high cost of e-fuels currently the largest impediment to their deployment, Chapter 4 focuses on factors that contribute to the steep cost of e-fuels and on opportunities for reducing them by 2030. Chapter 5 analyses the impacts of an accelerated deployment of low-emission e-fuels for aviation and shipping during this decade, while Chapter 6 outlines the resource needs associated with such deployment. Finally, Chapter 7 discusses policy implications of the analysis and outlines possible next steps to enable an accelerated deployment.

Chapter 2. Decarbonisation trends

Transport fuel demand

Global oil demand is forecast to peak this decade as energy transitions gather pace and transport fuel demand growth slows. Led by continued increases in air travel and petrochemical feedstock uptake, total oil consumption (excluding biofuels) is nevertheless forecast to rise to 102 mb/d by 2030, 5 mb/d above 2022 levels. Some economies, notably the People's Republic of China (hereafter, "China") and India, will continue to register growth throughout the forecast. By contrast, oil demand in advanced economies may reach a peak this year – a result of the sweeping impact of improvements in vehicle efficiencies and electrification.

Figure 2.1 Annual oil demand growth, 2022-2030



Note: Other transport demand includes aviation, marine and rail.
Source: IEA (2023), Oil 2023 – Analysis and forecast to 2028, extended through 2030.

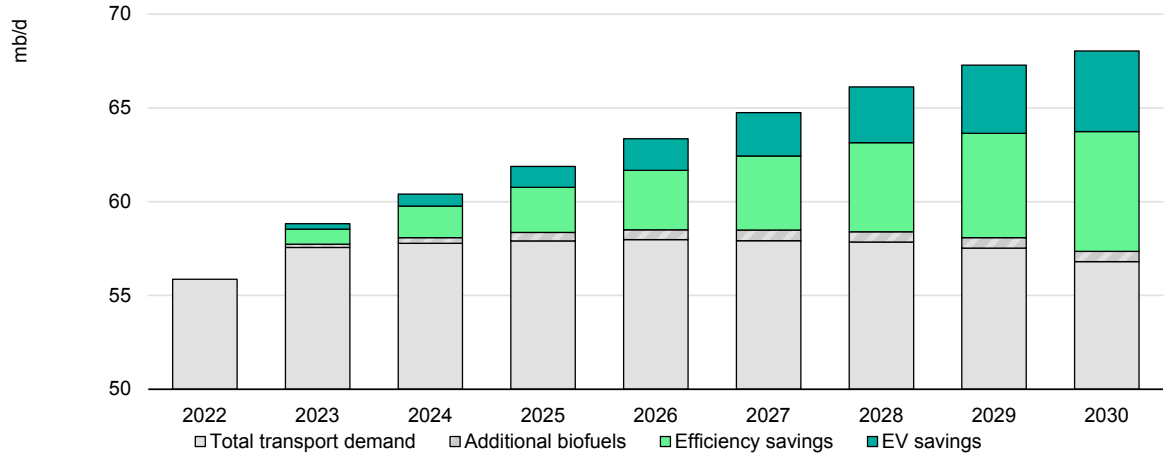
Oil demand used as a transport fuel is set to decline from 2026 due to efficiency improvements and a rapid uptake of hybrid and EVs and increased biofuels use. The pace of change varies across different transport modes and depends on the potential for direct electrification.

Global road transport fuel demand, accounting for nearly half of total oil consumption, is forecast to decrease from 2024. The proliferation of vehicle efficiency improvements along with surging sales of hybrid and electric vehicles are driving down average fuel consumption and CO_2 emissions from the road transport sector. In 2023, nearly one in five cars sold were electric, an increase of roughly 35% from the year before. If the pace of growth in EV sales over the

past two years is sustained through 2030, CO_2 emissions from cars can be put on a path in line the NZE Scenario.

Projected oil consumption for 2030 would be 7.5 mb/d higher without the savings from new EVs and efficiency improvements since 2022, and a further 0.5 mb/d without additional biofuels production. Post-pandemic changes in consumer behaviour provide additional demand reductions, as hybrid working and video conferencing have become established for some business sectors in advanced economies.

Figure 2.2 Impact of EVs and efficiencies on total transport oil demand, 2022-2030



Source: IEA (2023), Oil 2023 – Analysis and forecast to 2028.

By contrast, global air traffic is expected to complete its sharp post-Covid rebound before the end of 2024. Thereafter, structurally increasing demand for long-distance travel, strongly associated with higher GDP in middle-income countries, will remain a pillar of overall growth. Total jet fuel demand will rise by 2 mb/d between 2022 and 2030, but a substantial improvement in aircraft fuel efficiencies means that it will take until 2027 to exceed 2019 levels. While global air traffic had recovered to virtually match pre-pandemic activity by the end of 2023, overall jet/kerosene demand remained 7% lower. This reflects substantial changes in fleet composition since 2019, with newer aircraft typically using 20-30% less fuel than the models being replaced. Oil used for marine bunkers is expected to increase by a further 300 kb/d through 2030, in line with growth in economic activity and trade. Efficiency gains, spurred by progressively tighter measures to reduce greenhouse gas emissions, will nevertheless temper demand growth.

To further reduce road transport and air travel, expansion of high-speed rail networks should be implemented. While rail is currently the least emissions-intensive mode of passenger transport, further electrification of diesel operations

wherever viable, as well as the use of biodiesel blends or hydrogen, would be needed to get on track with the NZE Scenario.

Tracking transport decarbonisation

Aviation

From 2010 to 2019, average fuel efficiency per revenue tonne kilometre (rtk) equivalent travelled improved by 1.8% per year thanks to the introduction of more efficient aircraft and engines, with gains over the decade nearly reaching the UN's International Civil Aviation Organization's (ICAO) aspirational goal of 2% per annum through 2050. In addition to technical efficiency advances in engine and airframe designs, improvements in payload and traffic efficiency (i.e. the weight of cargo and number of passengers carried per aircraft) have also contributed to reducing the energy intensity of aircraft operation. However, efficiency gains have not kept up with demand growth, which rose at an average rate of over 5% annually between 2010 and 2019. Further efficiency progress was made during the Covid-19 pandemic, when a number of aircraft were retired and replaced by newer models typically using 20-30% less fuel.

Currently, demand for aviation fuel is dominated by jet kerosene, while sustainable aviation fuel (SAF) accounts for less than 0.1% of all fuels consumed. Manufacturers and operators are increasingly testing flights that are entirely fuelled by SAF, which can be deployed in current infrastructure, engines and aircraft with minor adjustments to fuel delivery equipment. However, planned production capacities will provide just 1-2% of jet fuel demand by 2027.

International shipping

The energy efficiency of ships is regulated by the International Convention for the Prevention of Pollution from Ships (MARPOL), Annex VI. For new ships, the Energy Efficiency Design Index (EEDI) needs to meet criteria that get more stringent over time, up to a reduction of emissions per unit of activity of 30% by 2025 compared to 2000-2010 levels. Similarly, existing ships are covered by the Energy Efficiency Existing Ship Index (EEXI). In addition, from January 2023, the Carbon Intensity Indicator (CII) regulates the operation of ships with increasingly stringent requirements. It has been estimated that nearly three-quarters of newly built containerships and general cargo ships already meet the post-2025 EEDI requirements, with energy savings of more than 50%. While low-emission fuels are going to play an increasing role in the marine sector, technological development and increased policy support will be needed to reduce dependency on fossil fuels in international shipping. This particularly concerns bunker fuel transport to seaports, bunkering infrastructure and protocols, onboard storage

tanks, fuel delivery systems, engines and emissions after-treatment and, crucially, training and safety in the use of the new fuels. Slow stock turnover is due to the long vessel lifetimes, at around 30 years on average but varying from 25 years for containerships to as much as 35 years for general cargo vessels. The current average age of containerships in service is around 14 years, 12 years for bulk carriers and 20 years for oil tankers, according to UNCTAD. Those three ship types taken together make up two-thirds of international shipping emissions, according to the IMO. This means near-term innovation, optimisation of ship design to allow for easy retrofitting, and zero-emission technology adoption are critical to putting international shipping on an ambitious emissions reduction track.

Road transport

Private cars and vans were responsible for more than 25% of global oil use and around 10% of global energy-related CO_2 emissions in 2022. Emissions from light-duty vehicles (LDVs) will need to fall by around 6% each year through 2030 to get on track with the NZE Scenario. EVs are the key technology to decarbonise road transport. Passenger EVs sales surged by around 55% in 2022 and 35% in 2023, to more than 18% of all new cars sold.

If the level of growth in EV sales posted over the past two years is sustained until 2030, CO_2 emissions from cars would align with a pathway towards the NZE Scenario. However, electric vehicles are not yet a global phenomenon. Outside of China, sales in developing and emerging economies have been slow to pick up due to the relatively high purchase price of an EV and lack of charging infrastructure.

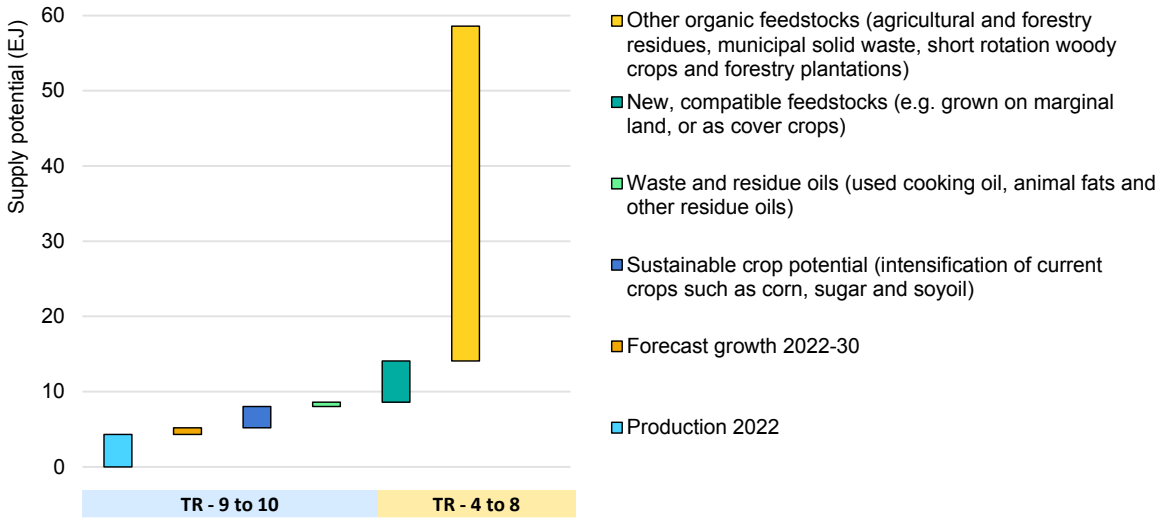
CO_2 emissions from heavy-duty vehicles (HDVs), including trucks and buses, need to peak rapidly and start declining in the coming decade to reach NZE Scenario milestones. HDV fuel economy standards and zero-emission vehicle mandates need to be adopted, and those that exist strengthened and harmonised to decarbonise the sector in parallel with policies that enable the supporting EV charging infrastructure. Electric and hydrogen fuel-cell HDVs need to be deployed now to enable emissions reductions in the 2020s and 2030s. Aligning with the NZE Scenario will require a drop in emissions of 15% by 2030 relative to their current level, declining at roughly 2% per year.

Biofuel supply potential

Liquid biofuels play a critical role in decarbonising transport because they can reduce emissions in hard to abate sectors such shipping, aviation and long-haul trucking, and are compatible with existing infrastructure. However, the availability of sustainable feedstock will limit supply from current technologies. Biofuel production in 2022 stood at 4.3 EJ, representing nearly 4% of global road transport

fuel demand. The vast majority, about 90%, of these fuels were produced from sugar cane, corn, soybean oil, rapeseed oil and palm oil. The remaining 10% was produced from waste and residue feedstocks such as used cooking oil and animal fats. Biofuel demand is forecast to expand to 5.3 EJ, representing 6% of forecasted road transport energy demand in 2030, driven by policies and planned project additions. Road transport accounted for nearly all liquid biofuels use in 2022, and its share declines only slightly to 98% by 2030.[1]

Figure 2.3 Liquid biofuel annual supply potential by feedstock type and technology readiness level, 2022-2030



Notes: The IEA's TRL scale aims to cover all relevant steps of the innovation journey, from concept to market maturity, and may differ from the scale used by other research institutes. Total supply potential assumes all 100 EJ of the IEA's estimated sustainable bioenergy supply were converted to liquid fuels. Total liquid fuel supply is near 60 EJ when accounting for conversion losses.

Sources: Existing and forecast growth from IEA (2022), Renewables 2022, sustainable crop potential and other organic feedstocks from IEA (2022), World Energy Outlook 2022, waste and residue potential and new, compatible feedstocks from the World Economic Forum's Clean Skies for Tomorrow Coalition. TRLs from IEA (2023), ETP Clean Energy Technology Guide.

Those feedstocks most readily available for liquid biofuels include vegetable oils, sugars, starches and increased collection of residues fats, oils and greases. All these feedstocks are already used today and can be processed using commercial technologies. However, supplies of this type are relatively limited, and could likely offset an additional 3% of transport fuel demand by 2030, beyond existing and forecast biofuel production. In some markets, such as the European Union, these feedstocks have already been capped in transport policies because of sustainability concerns. Globally, feedstock supplies of this type would bring total liquid biofuel supply potential to 9 EJ by 2030 at production costs between

[1] Forecast biofuel production values are based on the main case in the Renewable Energy Market Update – June 2023 and extended to 2030 from 2028 using the global production growth trend from 2022 to 2028.

USD 25/GJ to USD 50/GJ for road transport (USD 15-25/GJ for fossil fuel gasoline and diesel), and USD 60/GJ for aviation (USD 20/GJ for fossil fuel jet fuel).

Expanding biofuels beyond 9 EJ would require other feedstocks that are available in larger quantities and do not compete for land resources for food and feed production. These include new feedstocks compatible with existing technologies that can be grown on marginal land or as cover crops. Current estimates stand at near 8 EJ of liquid biofuel potential. However, these growing techniques have not been widely adopted for biofuel production, come at higher costs, require strict sustainability criteria and dedicated policy support, and there may also be competition for other bioenergy uses.

Other organic feedstocks such as agricultural and forestry residues, as well as municipal solid waste, offer additional supply potential but are not yet being deployed at scale and compete with other bioenergy uses. The opportunity for expansion is substantial, with an estimated 40 EJ of liquid biofuel potential. However, realising this potential depends on processing woody and fibrous residues using technologies like cellulosic ethanol and biomass gasification. Considerable investments in these technologies and supply chains will be required to commercialise and deploy at scale. Although spending on these technologies is accelerating globally, including commercial scale projects, the total forecast production remains small. Globally, biofuel projects that aim to use new and compatible feedstocks and woody residues are projected to contribute only 0.2 EJ of additional supply by 2030, a mere 4% of the global biofuel production.

In addition, there is competition for other organic feedstocks for biogas production, as solid bioenergy for heat and power applications, so liquid biofuels would only garner a share of this potential. That share will depend on mandates, costs and the relative value of the feedstocks in producing different forms of energy.

In some instances, technology can also be used to shift feedstocks from one biofuel product to another. For example, ethanol accounts for half of biofuel production today and is used in gasoline vehicles. As vehicle efficiency and EVs start to reduce motor gasoline demand to 2030, a surplus of ethanol production could develop if ethanol blend rates remain low and blending mandates do not increase. Alcohol-to-jet offers a way to convert ethanol into sustainable aviation fuel. Hydroprocessed esters and fatty acids (HEFA) facilities can also be built and operated or retrofitted to vary renewable diesel/bio-jet production using the same feedstocks.

Biofuels hold considerable promise for reducing greenhouse gas emissions in the transport sector, but they are likely to be complemented by other efforts such as low-emission e-fuels. Moreover, much of the existing and planned biofuels production is dedicated to road transport through 2030. Expanding biofuel production for road, aviation and marine consistent with a net zero pathway would

require near 6 EJ of additional supply, which would require all of the IEA's estimated sustainable supply from agriculture and residue fats, oils and greases commonly used today, plus significant investment in new agricultural practices and technologies to access more of the readily available feedstocks. Stringent supply and demand policies with strict sustainability criteria would also be needed to drive investment and ensure sustainable feedstock use.

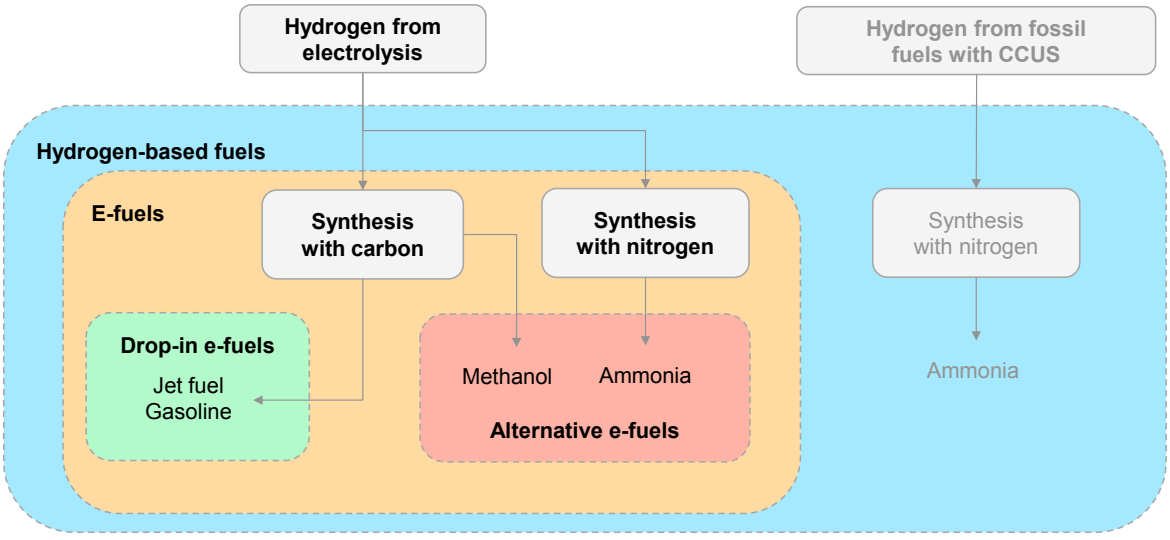
Chapter 3. Status and outlook

What are e-fuels?

E-fuels are fuels obtained from electrolytic hydrogen. E-fuels are low-emission fuels when their hydrogen is produced using low-emission electricity and any carbon inputs are obtained in a way that leads to low life-cycle greenhouse gas emissions. Various different fuel types can be produced along this basic route. The combination of hydrogen with nitrogen produces ammonia, a gaseous chemical that is used today mainly as a precursor to fertilisers, but that also has application as a fuel. The combination with carbon opens the possibility to produce a wide range of products, from alcohols to ethers and from hydrocarbon fuels to lubricants.

Different fuel products can be further categorised by their ease of use. Drop-in e-fuels such as e-kerosene, e-diesel and e-gasoline are compatible with existing refuelling infrastructure and can be blended with limited constraints with petroleum-derived counterparts. By contrast, alternative e-fuels such as e-ammonia and e-methanol require investments in distribution infrastructure and end-use equipment to enable their use in the transport sector.

Figure 3.1 E-fuels and production routes considered in this report

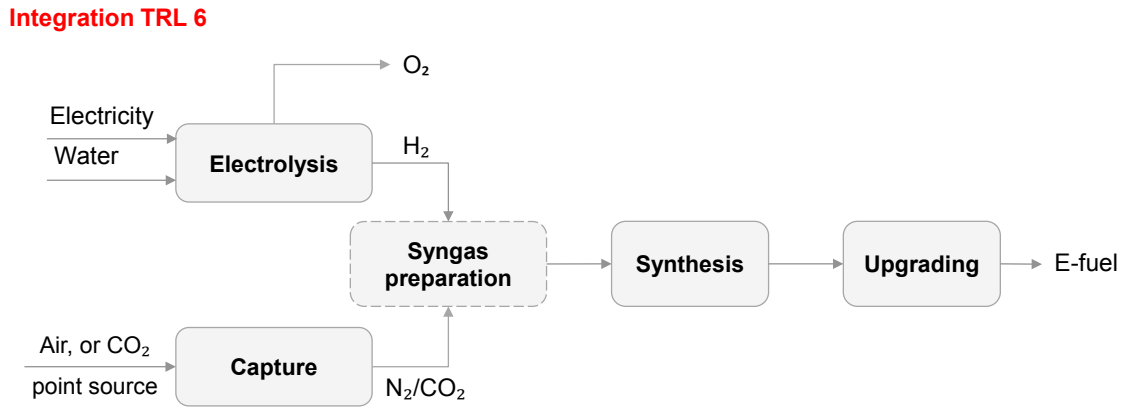


Note: E-fuels represent a subset of hydrogen-based fuels, a category that also includes fuels obtained from hydrogen produced from fossil fuels with CCUS.

Electrolysis is the central component of an e-fuels process. It involves splitting water molecules into hydrogen and oxygen with an electric current and separating them into two product streams. Water electrolysers are based on a small number of technologies, including alkaline, proton exchange membrane (PEM), solid oxide electrolyser cell (SOEC) and anion exchange membrane (AEM) based systems. Alkaline technologies dominate the market today, although PEM solutions are also commercially available. SOEC and AEM electrolysers are currently in the demonstration phase, with the former at a large scale, and are expected to be commercialised soon.

The production of e-fuels requires essentially four steps: production of hydrogen, capture of nitrogen (N_2) or carbon dioxide (CO_2), conversion of the feed gas into new molecules in a synthesis, and final upgrading of the raw product. Before the synthesis, the reactants (H_2 and CO_2 or N_2) need to be mixed in the right amounts to comply with the stoichiometric requirements of the downstream synthesis.

Figure 3.2 Schematic illustration of the main components of an e-fuels process



Note: A dedicated syngas preparation step (indicated with a dashed line) is required for Fischer-Tropsch, but not for the methanol or the ammonia process. TRL refers to the IEA extended Technology Readiness Level scale.

The production of liquid hydrocarbon fuels via the Fischer-Tropsch (FT) route requires an additional syngas preparation step that converts the CO_2 feedstock to carbon monoxide (CO), a more readily usable form of carbon required by the technology. Several approaches are possible, all having a relatively low technology readiness level (TRL) today.

Other main unit processes required to produce e-fuels are all commercially available at large scale. However, integration of these unit processes into a fully operational plant currently has a low technology readiness level, with the largest plants represented by large prototypes (TRL 6).

Current status

The use of electrolytic hydrogen to obtain hydrogen-based products is not a new technology. The production of ammonia from water and air using grid electricity or hydropower was common in the first half of the 20th century, with several plants having a capacity above 100 megawatt electrical (MW_e). However, a widespread switch to more cost competitive production based on unabated fossil fuels (mostly steam reformers using natural gas, but also coal gasification in China) resulted in the decommissioning of these plants. The last plants to seize their operations were in Zimbabwe with 100 MW_e of electrolysis capacity decommissioned in 2015 and Egypt with 165 MW_e of electrolysis capacity decommissioned in 2019. Today only one plant has survived this technology shift: Industrias Cachimayo in Peru. The plant has been in operation since 1965, producing around 50 t of ammonia/d based on a 20 MW_e electrolyser.

The need to decarbonise fossil fuel use has led to a renewed interest towards the technology, this time powered by variable renewables. The majority of the projects that are currently in operation are small-scale demonstration projects, such as the ETOGAS pilot plant (Germany), using a 6 MW_e electrolyser to produce methane. However, in the case of ammonia and methanol production, there are a couple of noteworthy exceptions due to their already existing use in the chemical industry. In China, the Ningxia Solar Hydrogen Project started operation in 2021. It is the world's second largest electrolysis project in operation with 150 MW_e capacity to produce methanol. The largest plant in operation today to produce ammonia, using only renewable electricity, is a 20 MW_e project that Iberdrola started operating in Spain in 2022. However, in this case, hydrogen from electrolysis is blended with hydrogen from unabated natural gas before it enters ammonia production.

There are currently more than 70 projects in operation globally to produce hydrogen from electrolysis that is then used to obtain hydrogen-based products, which could be used as e-fuels. The vast majority of these projects are at demonstration scale. The total production from all these projects is very small, resulting in less than 20 kt (kt H_2) production,[2] the majority of which is used in the production of methanol and ammonia for industrial applications.

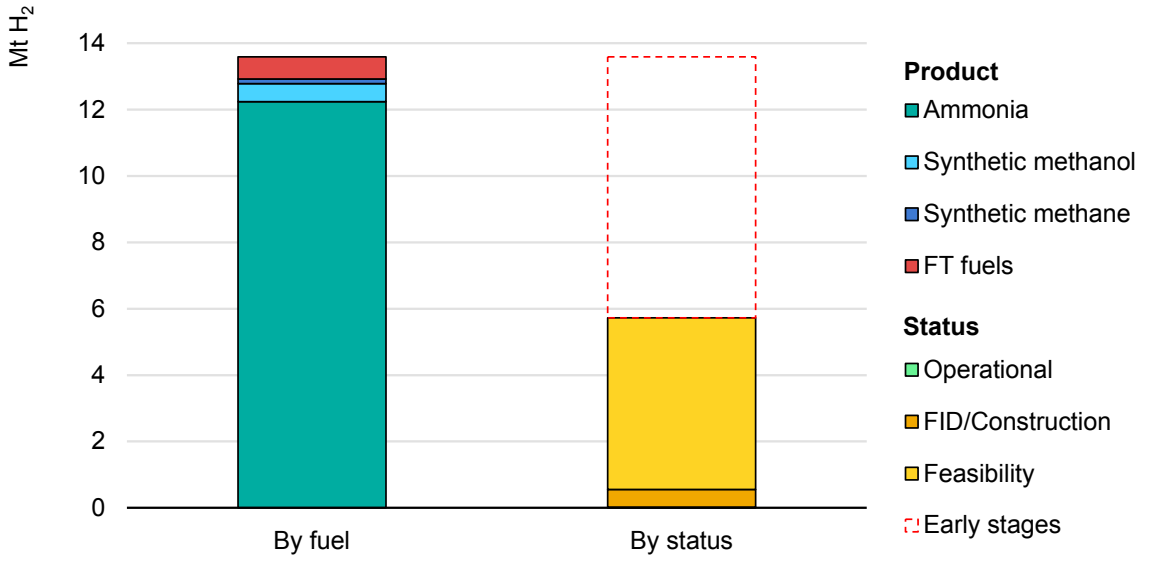
Announced projects

Despite limited deployment today, the number of announced projects is increasing at a rapid speed. If all projects currently under development were to be realised on time, the supply of hydrogen from low-emission electricity for e-fuels production

[2] Quantities of e-fuels in this section are given in hydrogen equivalent terms, i.e. the "stoichiometric" hydrogen requirement to produce the e-fuel.

could reach almost 14 Mt by 2030.[3] This represents nearly one-third of the potential production of all announced low-emission hydrogen projects, which accounts for 38 Mt. However, the majority of projects (representing nearly 8 Mt of hydrogen) are at very early stages of development and only a small fraction (around 4%) have reached a firm final investment decision (FID). Without further policy action to close the cost gap and to stimulate demand, producers of low-emission e-fuels will not secure sufficient off-takers to underpin large-scale investments, jeopardising the realisation of the current project pipeline.

Figure 3.3 Global electrolytic hydrogen production that could be used to produce e-fuels by fuel and status based on announced projects, 2030



Notes. FID = final investment decision; FT = Fischer-Tropsch. For ammonia and methanol, the figure includes all announced projects for the production of these products, including projects aiming to utilise them in fuel applications, in industrial applications, without a disclosed final use or for multiple purposes.

Source: IEA (2023), Hydrogen Production and Infrastructure Projects Database.

Of the total potential e-fuel supply from announced projects, ammonia accounts for 90%, followed by FT fuels (5%), methanol (4%) and methane (1%). The high share of ammonia among announced projects suggests that the main driver for the production of hydrogen-based products using electrolytic hydrogen is coming from ammonia's industrial applications instead of its potential use as a fuel. This is a sign of the fertiliser industry's readiness to absorb a significant share of the supply as a drop-in feedstock for its existing processes. Around one-quarter of the capacity of projects aiming to produce e-ammonia specifically target its use in the fertiliser industry. The lower risk presented by this application means their share

[3] This would fall to below 6 Mt if early-stage projects would be excluded (e.g. projects where only a co-operation agreement among stakeholders has been announced).

of projects that have at least taken FID is double (8%) that of the overall pool of projects. In addition, ammonia is already a globally traded commodity, with an operating market in fertiliser applications and infrastructure already in place.

The potential to trade low-emission e-ammonia in a global market is another important driver for projects development. Ammonia trade is also attractive for its potential applications as low-emission e-fuel in power generation and shipping, since ammonia in many cases is the cheapest low-emission e-fuel when accounting for transport and storage costs. Its use as a hydrogen carrier, converted back into hydrogen at the destination, has also attracted some interest, but this involves an energy loss in the reconversion that makes the economics of the supply chain more uncertain. Export-oriented projects account for nearly 60% of the announced capacity, but only two projects (the NEOM Green Hydrogen Project in Saudi Arabia and a joint project between Scatec and ACME in Oman) have taken a FID and started construction.

Role of fossil CO_2 emissions in the production of e-fuels

CO_2 that is used to produce e-fuels is ultimately released back into the atmosphere, and therefore it is important to consider the overall life-cycle emissions of different e-fuel production pathways. Emissions reduction of e-fuels compared to relevant fossil fuels depends on the source of the CO_2 (biogenic, air-captured or fossil), the emissions intensity of the product or service the fuel is displacing, and the emissions intensity of the energy used for the conversion process.

For example, e-fuels made from biogenic or air-captured CO_2 can potentially provide full emissions reduction, making them the primary production pathway that is consistent with achieving net zero emissions by mid-century. By contrast, when made from fossil CO_2, e-fuels can only reduce part of the system's emissions, either from the plant where the CO_2 is captured, or through displacing an emissions-intensive fuel. This is provided that the CO_2 emissions associated with capturing, transporting, and converting CO_2 are lower overall than those emitted during production of the displaced fuel.

Based on project announcements, there are plans for around 15 large-scale (over 100 000 t CO_2 per year) capture projects on industrial facilities targeting the use of fossil CO_2 in the production of e-fuels. Using fossil CO_2 from industrial sources could play a transitional role to initiate e-fuel production as supply from biogenic sources and direct air capture scales up over time. To improve the competitiveness of e-fuels compared to their fossil counterparts, projects are likely to require policy support. While fossil-based CO_2 feedstock sources could initially benefit from some support to enable early market creation and reduce technology risks, e-fuel policies

should take into account overall life-cycle emissions. Robust, transparent and mutually agreed emissions accounting methods need to be in place to quantify emissions allocation and reduction and avoid double counting. This is particularly relevant for internationally traded low-emission fuels.

In any event, fossil-based facilities investing in CO_2 capture for e-fuel production today may need to evaluate future options for that captured CO_2 to eventually be permanently stored.

The fact that ammonia does not need carbon in its production leads to simplified supply chains and lower production costs making it an attractive early mover. The production of other low-emission e-fuels needs to consider the availability of carbon feedstock (notably from biogenic sources) in addition to renewable energy resources in siting of the projects. These additional limitations also explain the lower number of projects under development and their smaller average scale, compared to ammonia projects.

In the case of methanol, several shipping companies have committed to building methanol fuelled ships. Projects linked to existing applications in industry account for nearly one-third of the total potential production from all announced projects, with more than 15% having at least taken FID. From the projects targeting fuel applications (mostly in shipping) only 1% have at least taken FID. In the case of methane, despite its use as an industrial feedstock, most of its existing demand is coming from fuel applications. The vast majority of projects under development target its use as a fuel, normally injected into gas grids, with a very minor share (much less than 1%) that have taken FID.

Geographic distribution

Large-scale ammonia production plants that use fossil fuels are mostly located in China, the Russian Federation (hereafter, “Russia”), the Middle East, the United States, the European Union and India. Commonly, these plants are located in regions with good availability of fossil fuels resources (coal in China and India and natural gas in Russia, the Middle East and the United States), minimising the need to build fuel supply chains. These regions are also responsible for the largest demand of ammonia, although there is some imbalance between production and demand, which leads to ammonia being traded around the world (amounting to around 10% of total production).

Figure 3.4 Map of announced projects for low-emission e-ammonia production

Note: Map also includes announced projects starting after 2030.
Source: IEA (2023), Hydrogen Production and Infrastructure Projects Database.

The development of e-ammonia projects follows a similar logic as large fossil-based production today (proximity to best resources) but leads to a very different geographical distribution. The biggest projects under development are located in areas with beneficial combinations of solar PV and wind resources, such as desertic areas in the Middle East, Africa and Australia, with other large projects located in Chile and the United States. China has a significant number of smaller projects in much more advanced stages of development, thanks to a combination of good resources and proximity to large demand centres.

When it comes to carbon-containing e-fuels, the need to source CO_2 feedstock presents an additional supply chain challenge that is also reflected in the geographical distribution of announced projects, showing a strong concentration of projects close to major industrial centres in Europe and the United States, and some large developments in South Africa. In Europe, the large number of announced projects is also highly influenced by policy drivers, such as mandates for the use of low-emission fuels in aviation and emissions standards in shipping.

Figure 3.5 Map of announced projects for carbon-containing low-emission e-fuels production

Note: Map also includes announced projects starting after 2030.
Source: IEA (2023), Hydrogen Production and Infrastructure Projects Database.

Policy environment

Low-emission e-fuels are gaining policy recognition as a decarbonisation solution, notably in the aviation and marine sectors. As of 2023, e-fuels can participate in existing regulations and tax incentives aimed at increasing demand and supply of low-emission transport fuels that cover nearly half of aviation and one-fifth of marine fuel demand. For instance, low-emission e-fuels can satisfy the EU's Renewable Energy Directive and are eligible for tax credits via the US Inflation Reduction Act. There are, however, only a few examples of dedicated low-emission e-fuel requirements. E-fuels are also included in many national hydrogen strategies.

International commitments

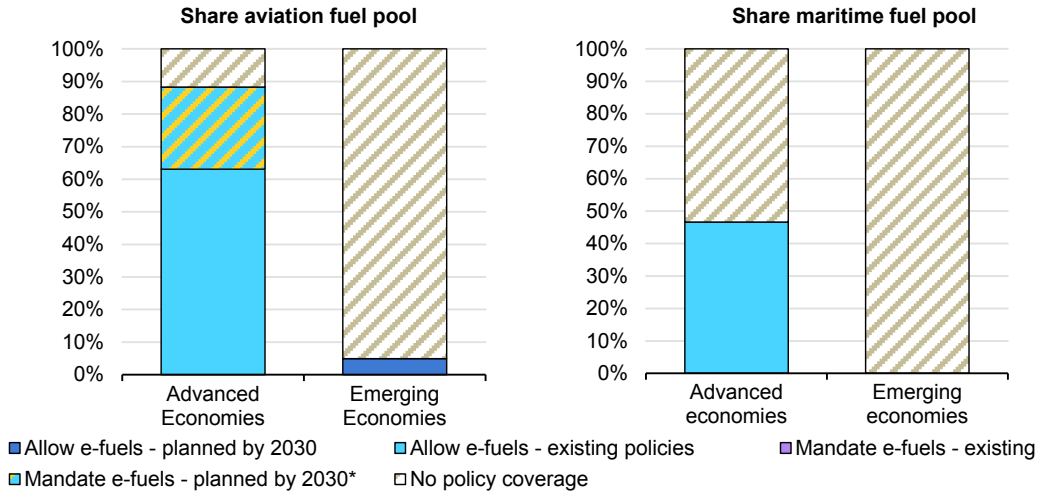
The global maritime and aviation sectors have adopted net zero emission ambitions, with low-emission e-fuels potentially playing a key role in international organisations' strategies. In 2022, 184 states set a long-term global aspiration net zero carbon emission goal for international aviation by 2050 through the UN's International Civil Aviation Organization (ICAO). According to ICAO, e-fuels could constitute 3% to 17% of aviation fuel by 2035 and 8% to 55% by 2050 depending on technology development and policy implementation. Although ICAO's Carbon Offsetting Reduction Scheme for International Aviation (CORSIA) programme includes sustainable aviation fuels (and so low-emission e-fuels), as yet there are no default life-cycle GHG intensity values for different e-fuel production pathways.

Similarly, the International Maritime Organization (IMO) in 2023 set a level of ambition of reaching net zero GHG emissions from international shipping close to 2050 and have at least 5%, and striving for 10%, of shipping energy to be net zero or near net zero by 2030. New policies supporting these targets are planned by 2027, to complement existing measures. The IMO further includes low-emission e-fuels as a technology pathway for reducing international shipping emissions.

Supply and demand regulations and incentives

Existing regulations and tax incentives aimed at increasing supply and demand of low-emission transport fuels often incorporate e-fuels to reduce greenhouse gas emissions, although only a few have dedicated low-emission e-fuel targets. Domestic programmes often feature blending mandates, renewable content requirements, and GHG intensity reduction targets. Globally, nearly half of aviation and one-fifth of marine fuel demand are already covered by such policies. Although dedicated e-fuel requirements mean that only 0.3% of total aviation and marine fuel demand is mandated to come from low-emission e-fuels by 2030.

Figure 3.6 Aviation and marine fuel pools with existing and proposed regulations and incentives that allow for, or mandate, low-emission e-fuel use in advanced and emerging economies, 2022-2030



*The blue/yellow shaded area includes policies that mandate e-fuels in regions that already allow for e-fuels.

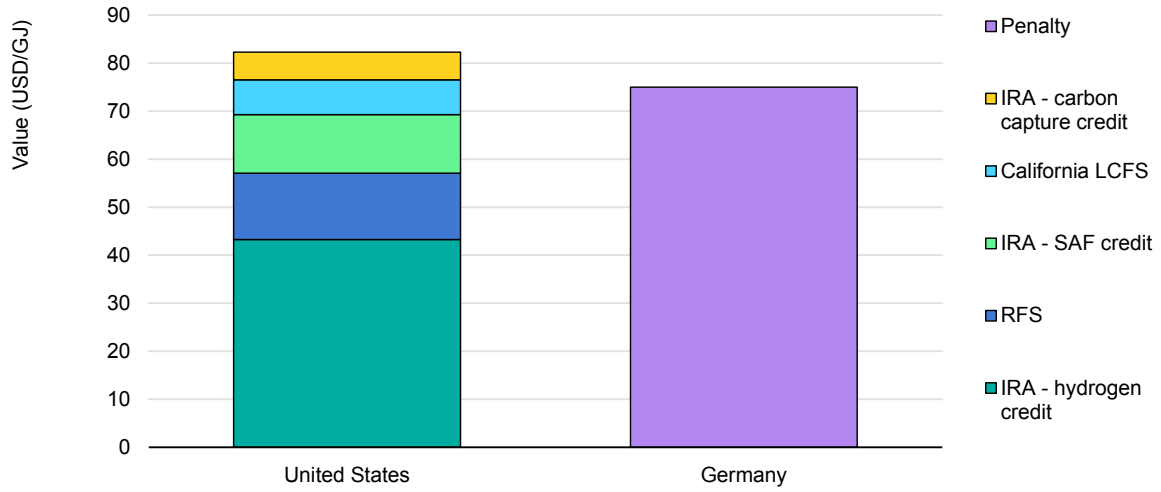
Notes: Regulations and incentives include supply and demand mandates and financial incentives for production and facility construction. In most cases e-fuels may be used to comply with existing regulations but are not mandated specifically, nor do they receive any additional financial incentive. In advanced economies the EU's Renewable Energy Directive and member states transpositions of it allow for e-fuels and often support via double counting. The ReFuelEU aviation and maritime proposed mandates also allow for e-fuels. The US IRA provides tax credits for clean fuels and facilities to create those fuels, including e-fuels. Canada's Clean Fuel Regulation also allows for e-fuels to comply with its regulation. Brazil is the only emerging economy proposing aviation GHG reduction targets that would allow for e-fuels. Only the EU and its member countries plan to mandate e-fuels by providing targets with penalties for not meeting those targets.

Carbon pricing, such as the EU Emission Trading System (aviation and marine fuels), Canada's carbon pricing system and California's cap and trade programme

also help by closing the cost gap between fossil fuels and low-emission e-fuels. Many other policies may influence e-fuel adoption such as vehicle efficiency and vehicle CO_2 requirements, air pollution regulations and fuel taxation rates. These policies are not considered here, but could form part of broader package of policies to support low-emission e-fuels.

In the United States, sustainable aviation fuels obtained from electrolytic hydrogen are eligible for several tax credits via the Inflation Reduction Act (IRA), low-carbon fuel standard credits and can generate Renewable Identification Numbers (RINs) under the Renewable Fuel Standard (RFS) programme. In theory, a single litre of low-emission e-kerosene could gain credit under all programmes with a combined value of USD 85/GJ.[4] The actual value e-fuel producers will realise depends on finalised IRA credits and RIN prices, and low-carbon fuel standard (LCFS) credit prices which fluctuate. If realised, credit stacking could prove a powerful incentive to produce low-emission e-fuels, despite the lack of any regulated requirement. Canada's Clean Fuel Regulation also sets GHG intensity reduction targets for the transport sector helping stimulate demand. While low-emission e-fuels are one compliance option, they do not receive any dedicated support.

Figure 3.7 Estimated credit values in the United States and penalty value in Germany for SAF made from low-emission e-kerosene, 2023



Notes: The United States includes the California LCFS at USD 100/t, D4 RIN prices at USD 0.45/litre based on the 2018-2023 average to 14 November 2023, the IRA credits for SEC. 40B (SAF credit), SEC. 45V (hydrogen credit), SEC. 45 Q (carbon capture credit) based on an e-fuel with carbon intensity of 15 g CO_2/MJ, made using hydrogen of less than 0.45 kg CO_2/kg H_2. Germany's penalty from its greenhouse gas reduction quota which includes a 2% target for renewable fuels from non-biological origins by 2030.

[4] Assuming SAF based e-fuel made using hydrogen with a carbon intensity of less than 0.45 kg CO_2-eq/kg H_2 and a total carbon intensity of 15 g CO_2-eq/MJ.

The European Union has set a dedicated e-fuel targets by 2030 via its ReFuelEU Aviation and FuelEU Maritime legislation. The aviation proposal targets a minimum 0.7% share in 2030-2031 and a 1.2% average low-emission e-fuel share over the time period. The target increases progressively to 35% by 2050, while the maritime proposal targets a 2% low-emission e-fuel share by 2034. E-fuels can also compete with other options to meet requirements under the Renewable Energy Directive. Within Europe, Germany has set a more stringent target of 2% SAF from low-emission e-kerosene by 2030, with a USD 75/GJ penalty for non-compliance.

In Brazil, the Fuel of Future Program includes a 1% GHG reduction target for aviation by 2027 climbing to 10% by 2037, and low-emission e-fuels are one option to meet the targets. As of 2023, Brazil was the only emerging economy with low-emission transport fuel policies that allows for e-fuels.

The United States, India, European Union, Japan, and Canada have incorporated e-fuels into their hydrogen strategies and roadmaps to bolster research and development. Brazil is also formulating a regulatory framework for low-emission e-fuels. Globally however, low-emission fuels are not expanding at a rate consistent with NZE Scenario ambitions.

Table 3.1 Country-level transport policies that allow for or mandate e-fuels, 2023

Region	Policy name	Language on e-fuels
European Union	Renewable Energy Directive (II and III)	RED III sets a combined target for e-fuels and advanced biofuels of 5.5% in 2030 of which 1% must be low-emission e-fuels. It also recommends a 1.2% RFNBO[5] target for maritime and to include double counting.
European Union	ReFuelEU – Aviation	ReFuelEU includes a sub-target for low-emission e-fuels of 1.2% on average over 2030-31 with an annual 0.7% minimum in 2030-31, climbing to 35% by 2050.
European Union	FuelEU – Maritime	FuelEU Maritime sets GHG intensity reduction targets with a sub-target for low-emission e-fuels of 2% by 2034, with double counting until 2034
Germany	Law for the Further Development of the Greenhouse Gas Reduction Quota	Sets aviation target of 0.5% low-emission e-fuel requirements by 2026 and 2% by 2030. Transport GHG reduction targets can also be met with low-emission e-fuels and receive double credits.
Finland, Lithuania and Portugal		Finland sets a target of 10% for biofuels or biogas produced from select feedstocks or renewable fuels from non-biological origin. These fuels are worth twice as much

[5] Renewable fuels of non-biological origin.

Region	Policy name	Language on e-fuels
		meeting the regulation. Lithuania requires 3.5% blending of advanced biofuels or biofuels from non-biological origin by 2030. In Portugal advanced biofuels and renewable fuels from non-biological origins (low-emission e-fuels) have a 10% target by 2030.
United States	Inflation Reduction Act	The IRA provides several credit options that low-emission e-fuel producers can apply for including the Alternative Fuel and Low-Emission Aviation Technology competitive grant programme, the Sustainable Aviation Fuel Credit, and other programmes for CCUS and hydrogen production.
Canada, California, Washington and Oregon		Canada and these three US states all allow for low-emission e-fuels within their respective low-carbon fuel and clean fuel programmes. California, Washington and Oregon low-carbon fuel programmes have varied between USD 22-206/t CO_2. At the time of writing Canada had not published credit prices.
Japan	SAF goal	Targeting 10% SAF by 2030 and low-emission e-fuels can participate.
Brazil	Future Fuel	Brazil's proposed SAF mandate would allow for low-emission e-fuels in theory, it is not yet in force.

Technical standards and GHG emission guidelines

To be utilised in current and future fuel systems and to comply with regulatory mandates, e-fuels must adhere to stringent standards for technical quality, safety and environmental impact, including GHG emissions. Carbon-containing e-fuels can be blended with existing fuels so long as they meet fuel quality and safety standards. In addition, ASTM has created a task force to develop specifications for 100%, unblended, e-fuels. Work is also ongoing to establish fuel quality guidelines for non-blended e-fuels. However, some fuels, such as ammonia, require new quality and safety standards, which the IMO and ISO are currently developing.

Table 3.2 Status of international technical, safety and life-cycle GHG emissions standards for e-fuels

Application	Fuel and safety standards	Life-cycle GHG emissions
Aviation	Would need to meet ASTM D7566 Annex A1 and Annex A5 or D1655.	Life-cycle guidelines and e-fuel pathways under development.
Marine	No specific fuel pathways. Marine fuels have used automotive diesel standards for HVO. (renewable diesel) EN 15940:2016 and EN 590 B7. Ammonia quality and safety standards under development. Interim Methanol Safety Guidelines MSC.1/Circ. 1621. Specifications of methanol as a fuel for marine applications – ISO/DIS 6583 (Under development) Products from petroleum, synthetic and renewable sources (marine fuels) – ISO/FDIS 8216-1 (Under development)	Life-cycle guidelines, but no e-fuel pathway. MARPOL Annex VI also regulates CO_2, NOx and PM.

Protocols and guidance for developing life-cycle GHG emissions estimates for e-fuels are pre-requisites for broad deployment as low-emission transport fuels. The European Union, the United Kingdom, Canada, and US state level policies, such as California's low-carbon fuel standard, already provide pathways and guidance for developing life-cycle GHG emission estimates for e-fuels. Japan also provides carbon intensity guidelines via its Recommended Guidelines for Greenhouse Gas and Carbon Intensity Accounting Frameworks for LNG/Hydrogen/Ammonia Projects. At the international level, CORSIA and the IMO provide guidance on developing life-cycle emission factors, but have yet to publish default values for e-fuel pathways. ICAO's Committee on Aviation Environmental Protection is developing e-fuel life-cycle emission pathways.

Chapter 4. Production costs

The cost of making low-emission e-fuels is determined by a number of factors, ranging from the price of electrolysers and electricity to heat integration opportunities and the value of by-products. An appropriate selection and development of a production site that has high-quality renewable resources can reduce costs already today, while technological learning and synergies with biofuels production can lead to further reductions. The purpose of this chapter is to provide an overview on the main factors that influence the cost of e-fuels and opportunities to reduce them by 2030.

Plant investment

Electrolysis is the main component of an e-fuels plant. The capital cost for an installed electrolyser (including the equipment, gas treatment, balance of plant, and engineering, procurement and construction) ranges from USD 1 700/kW and USD 2 000/kW (for alkaline and PEM, respectively, based on data from industry and project developers). This is around a 9% year-on-year increase compared to the capital cost range in 2021. However, in Europe, some project developers have observed even higher inflation values, up to 40% in certain cases.

Alkaline electrolysers manufactured in China are, in terms of CAPEX, much cheaper than those manufactured in Europe or North America, at around USD 750-1 300/kW for an installed electrolyser, and could be as low as USD 350/kW. The lower costs reflect cheaper labour costs and more developed supply chains for raw materials and components in China.[6] In addition, a recent report pointed out that Chinese manufacturers are using lower technical standards in the equipment that they manufacture. For exports, adjustments need to be made to Chinese electrolysers to comply with standards in other countries, possibly leading to higher costs.

By 2030, electrolyser costs are expected to fall significantly as deployment drives economies of scale, innovation, standardisation, more competitive markets and lower financing costs. Based on announced projects, global installed electrolyser capacity could increase from around 1 GW in 2022 to 55 GW by 2025, and reach 175 GW in 2030. Assuming an 18% learning rate for electrolyser stacks and 5-12% for other components, the cost of an installed electrolyser could be reduced by 50% by 2025 and 60% by 2030, reaching about USD 800/kW_e.

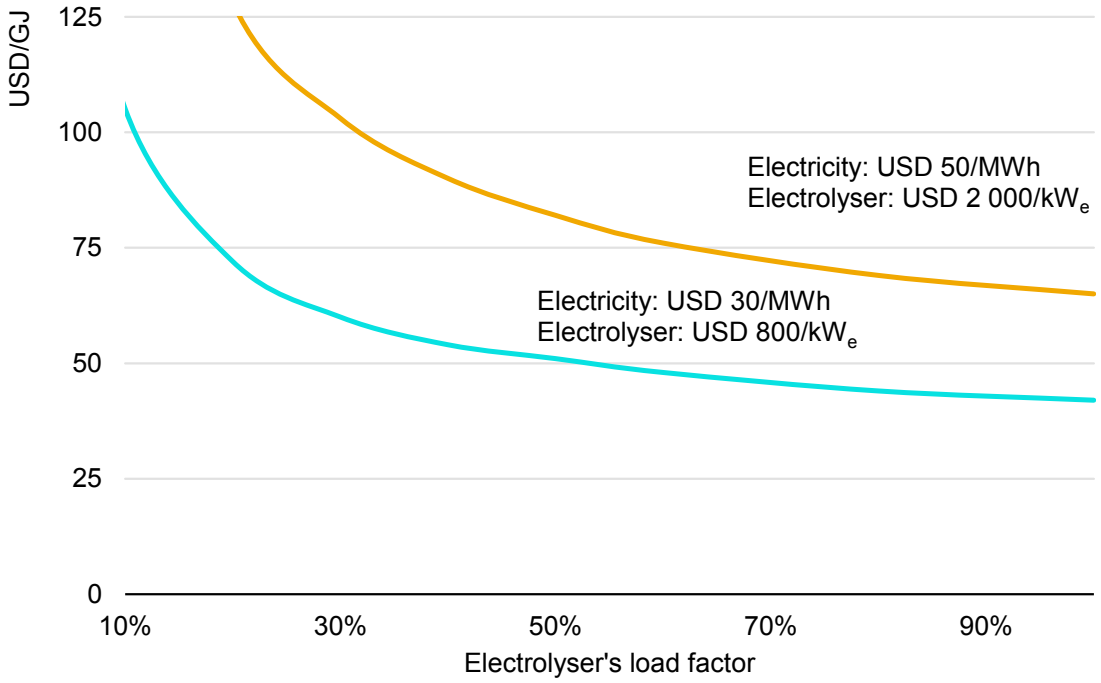
[6] Source: "Electrolysis system CAPEX could drop 30% by 2025", BloombergNEF, 21 September 2022.

Electricity price

Electricity prices play a decisive role in the cost of e-fuels. At USD 50/MWh, the cost contribution of the electricity price is already USD 25-35/GJ (USD 1 000-1 500/toe) depending on the end product, before considering any investments or other consumables. In addition, the amount of hours electricity is annually available plays an equally critical role as it directly influences the load factor of fuel production and therefore the contribution that plant investment has on the levelised fuel costs. The combination of price and availability is therefore a key consideration, which also depends greatly on whether electrolysers are connected directly to renewables, or to the electricity grid.

Interest in connecting e-fuels production to electricity grids has been partly motivated by the increased penetration of variable renewable energy sources in the electricity markets that has led to low or even negative power prices and created demand for balancing services. Grid-connected electrolysers have been envisioned to operate during the low-price hours of the wholesale electricity market, converting cheap electricity to valuable low-emission fuels or chemicals and reducing curtailment needs.

Figure 4.1 Impact of electrolyser's load factor on the levelised cost of e-kerosene at two different electricity and electrolyser prices



Notes: Load factor is measured as the average fuel output over a year, relative to the maximum fuel production capacity. Financial assumptions: the weighted average cost of capital (WACC) 5%, economic life 25 years. Performance (all in LHV): electrolyser 69%, H_2-to-syncrude 57%, transport fuel mass yield from FT jet fuel refinery 85%, electricity consumption of compression and refining 540 kWh/t. CAPEX: RWGS reactor + FT synthesis + refinery USD 1 200/kW$_e$. OPEX: electrolysis 1.5%/yr of CAPEX, synthesis 3%/yr of CAPEX. Consumables: CO_2 feedstock USD 30/t, water USD 2/m^3.

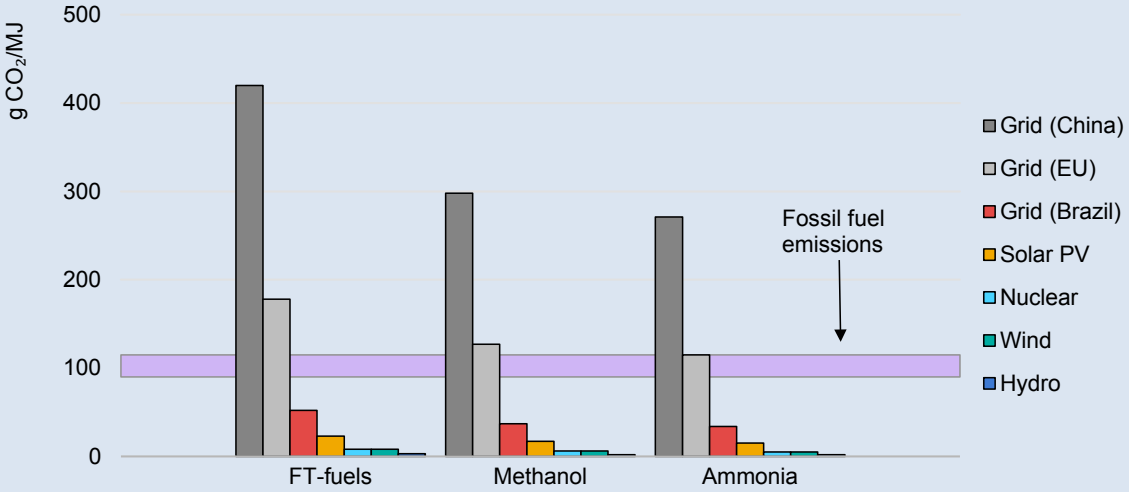
However, the cost of e-fuels is highly sensitive to the electrolyser's load factor, and if the amount of annually available low-price hours in the wholesale electricity market is small, the contribution of the plant investment to the production cost is high. Assuming a constant average electricity price, the levelised cost of e-fuels starts to increase very quickly (see Figure 4.1) when the plant's load factor drops below 40%.

Rather than focusing on exploiting small amounts of low-cost hours, grid-connected production of e-fuels should identify electricity markets with low median wholesale electricity prices coupled with low grid CO_2 emissions. The impact of high price hours can be minimised by switching the plant to minimum load or completely shutting down the electrolysers while relying on a buffer storage that keeps supplying hydrogen to the less flexible fuel synthesis.

Impact of electricity source on GHG emissions of e-fuels

The life-cycle GHG emissions of e-fuels depends on the carbon intensity of the electricity used and source of CO_2 feedstock (for the latter see Chapter 3, box "Role of fossil CO_2 emissions in the production of e-fuels"). When using low-emission electricity (e.g. from renewables or nuclear power plants) and assuming zero life-cycle emissions from the carbon feedstock (e.g. from biogenic CO_2), GHG emissions of the produced e-fuels are at the level of 2-25 g CO_2/MJ, or 75-98% lower than emissions from fossil fuels they replace.

GHG emissions related to the production of selected e-fuels by electricity source



Notes: Only electricity-based emissions are considered in this figure for e-fuels. CO_2 feedstock is assumed to be from a high-concentration biogenic source. The range for fossil fuel emissions is based on life-cycle emissions of liquid hydrocarbon fuels at 90 g CO_2/MJ, and on methanol and ammonia at 110 g CO_2/MJ.

However, using grid electricity can lead to very high emissions. For example, operating an electrolyser with China's average 2022 grid emissions (594 g CO_2/kWh) would lead to e-fuels having 3-4 times higher emissions than of comparable fossil fuels. With the EU's 2022 average grid emissions (252 g CO_2/kWh), hydrogen-based fuel emissions would still be slightly above of comparable fossil fuels. However, with Brazil's average emissions (74 g CO_2/MJ) in 2022, hydrogen-based fuels would provide 45-70% GHG reduction compared to equivalent fossil fuels.

In practice, emissions related to the production of e-fuels with grid-connected electrolysers can be either higher or lower than a value estimated from average grid intensities. For example, a plant can choose to minimise its production during times of high grid carbon intensity, which would reduce average emissions (but would also reduce the plant's load factor). On the other hand, if the additional electricity demand created by electrolysers is supplied from unabated fossil fuel power plants, resulting fuel emissions could be significantly higher than what could be estimated based on average grid intensities.

Producers or low-emission e-fuels could also procure electricity through PPAs (Power Purchase Agreements) by signing a contract directly with a producer of low-emission electricity. This could take either the form of a physical PPA where contractual partners are located in the same grid and bidding area, or a financial PPA where the contracting parties can be located and/or operating on different grids and even in different countries.

PPAs can offer several advantages to each party. For clean electricity developers, they bring the revenue certainty needed to secure investment in the plant. For the low-emission e-fuels producers, engaging in a PPA allows for long-term price certainty. In addition, it offers a pathway to procure low-emission electricity when connected to a high-emission grid. Policies that support low-emission e-fuels may include requirements on how electricity needs to be procured in order to prevent fossil-powered grid electricity being used to produce fuels.

They may require that e-fuels are produced from new low-emission electricity projects instead of electricity from existing facilities (so-called additionality requirement). They may also set rules on temporal correlation, i.e. how often e-fuel producers need to prove that their electrolysers have been powered with low-emission electricity (usually either hourly, weekly, monthly or annual matching). Finally, there can be also requirements on grid proximity, e.g. e-fuels could be required to be produced in the same control area as their low-emission electricity source.

Emissions also depend on the choice of end product as the efficiency of converting hydrogen to fuels varies. Ammonia can be produced with the highest efficiency, followed by methanol and Fischer-Tropsch (FT) fuels. As a result, FT fuels are most sensitive to the carbon intensity of electricity, being generally 40% higher than

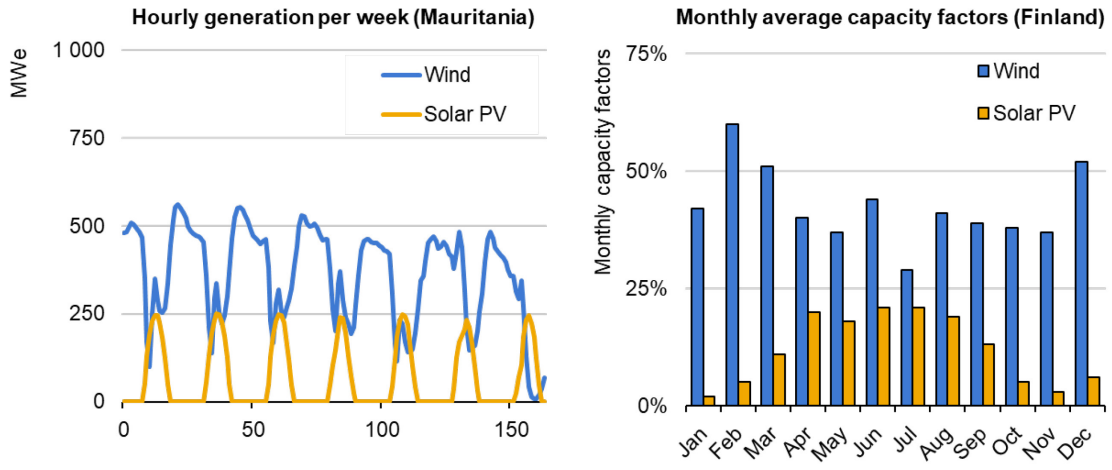
methanol's and 50% higher than ammonia's emissions using the same electricity. Indicative threshold values for the emissions intensity of electricity that delivers equal emissions to their equivalent fossil fuels are 130 g CO_2/kWh for FT fuels and around 200 g CO_2/kWh for ammonia and methanol.

Captive renewables

Renewable power is set to grow very significantly in the coming years as expanding policy support, growing energy security concerns and improving competitiveness against fossil fuel alternatives drive strong deployment of solar PV and wind power. Major reductions in the cost of wind and solar PV electricity have created interest towards using variable renewables directly to produce low-emission e-fuels in locations that have high-quality renewable resources and vast amount of available land for large-scale project development. At the best locations, capacity factors for producing electricity from renewables can exceed 50% for onshore wind and 25% for solar PV. However, focusing on locations with good complementarity between wind and solar resources might offer better opportunities for producing low-cost low-emission e-fuels than sites with only high-quality wind or solar resource.

Wind and solar resources can be considered complementary at a given location when they smooth each other's variation in electricity generation. In addition, complementarity should be considered across multiple timescales. An example of a short duration complementarity is a situation where intense solar radiation during the day is supplemented by strong winds during the night (see Mauritania in Figure 4.2). Similarly, an example of a long duration complementarity is a situation where solar radiation is mostly received during the summer months while wind resource is on a higher level during the darker winter months (see Finland in Figure 4.2). While complementarity over short durations can depend on the geography and topology of a given site, seasonal complementarity is strongly dependent on climatic conditions.

Figure 4.2 Hourly generation patterns for wind and solar in Mauritania (left) and monthly capacity factors for Finland (right)



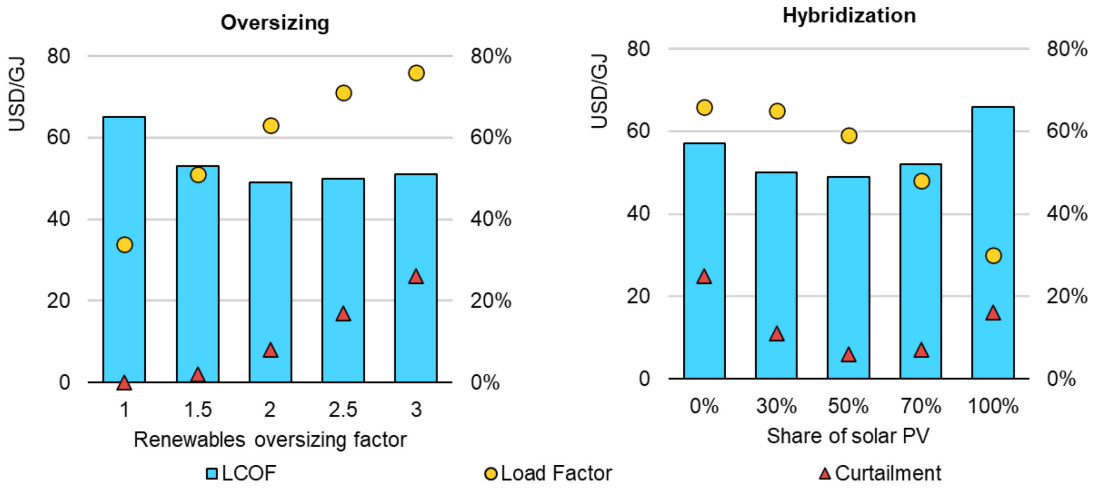
Note: The Mauritania example is based on a 1 000 MW hybrid power plant with a 40% capacity share of solar PV and a 60% share of onshore wind. Weather data from Renewables.ninja.

Equally important to identifying a suitable production site is to optimally develop its wind and solar resources by dimensioning different components of the e-fuels plant through oversizing and hybridization.

Oversizing is an optimisation approach where the combined installed capacity of wind and solar PV is dimensioned larger than the installed electrolysis capacity. Oversizing can increase the load factor of an e-fuels plant beyond the capacity factor of the electricity source as it allows electrolysers to run on high load even during times of lower generation from renewables. An economically optimal amount of oversizing is site specific and depends on the relative costs of plant components. At high electrolyser prices there is a strong economic incentive to increase the load factor of the e-fuel process, even if it results in curtailing part of the electricity during peak generation.

Already relatively small amounts of oversizing can lead to significant improvements in load factor. However, as the amount of oversizing is further increased, the benefits start to level off while the need to curtail starts to increase exponentially. In the example illustrated in the Figure 4.3 (left panel), the production cost is minimised by applying a renewables oversizing factor of about two. At this level, the annual capacity factor of an e-fuels plant reaches 62% solely based on variable renewable energy without any need for intermediate buffer storage.

Figure 4.3 The impact of oversizing and hybridization on the levelised cost of low-emission e-kerosene



Note: Oversizing factor is defined as the installed power capacity divided by electrolyser capacity. The example features an e-kerosene plant based in US Midwest with a 18% capacity factor for solar PV and 44% for onshore wind. In the left panel the share of solar PV is 40%, in the right panel the oversizing factor is 2. All assumptions are for 2030. Financial: WACC 5%, economic life 25 years. Performance: electrolyser 69% lower heating value (LHV), H_2-to-syncrude 57% (LHV), transport fuel mass yield from a FT jet fuel refinery 85%, FT synthesis minimum load 30%, electricity consumption of compression and refining 540 kWh/t. CAPEX: solar PV USD 690/kW, wind onshore USD 1 160/kW, electrolyser USD 800/kW_e, H_2 storage USD 400/kg, RWGS reactor + FT synthesis + refinery USD 1 200/kW_e. OPEX: onshore wind USD 10/MWh (today and 2030), solar PV USD 10/MWh (today), USD 5/MWh (2030), electrolysis 1.5%/yr of CAPEX, synthesis 3%/yr of CAPEX. Consumables: water USD 2/m^3, CO_2 feedstock USD 30/t. Weather data from Renewables.ninja.

Hybridization is a complementary optimisation approach to oversizing, used to find an economically optimal capacity mix of wind and solar PV generation for an e-fuels production plant. While hybridization does not contribute to higher capacity factor, it can be used to minimise curtailments for a given amount of oversizing. While oversizing depends on the relative costs of plant components, an economically optimal amount of hybridization is site specific. In the example illustrated above, the production cost is minimised at 40-50% share of solar PV in the capacity mix. At this level the annual curtailments are only 6% and significantly less than in a situation where power supply would be based solely on solar PV (18%) or wind (23%).

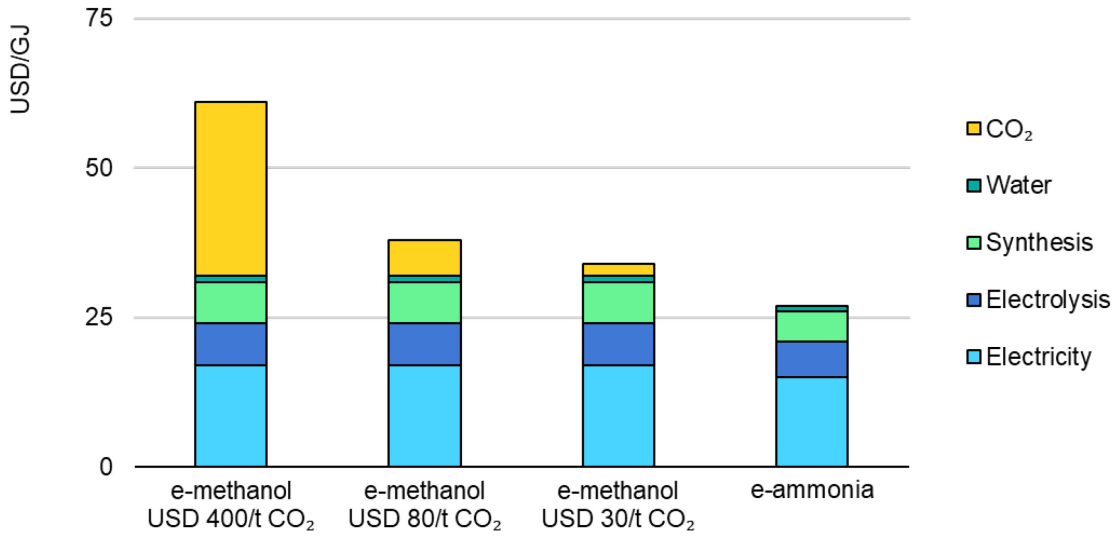
Cost of CO_2 feedstock

With the exception of ammonia, e-fuels need to source carbon in the form of CO_2 for their production. The cost of capturing CO_2 feedstock is largely determined by its initial concentration. From high-concentration sources like fermentation processes, carbon dioxide is available at a nearly 100% pure stream that only requires drying and compression before it can be utilised. Under such conditions, CO_2 can be captured cheaply at around USD 20-30/t CO_2. E-fuel plants can also source CO_2 feedstock from biomass combustion plants. However, the

concentration of CO_2 is much lower in flue gases (10-20 vol%) compared to fermentation processes, increasing capture costs to around USD 60-80/t CO_2.

If biogenic point sources are not available for utilisation at the production site, e-fuel plants could source CO_2 feedstock from the atmosphere with DAC. A wide range of cost estimates are available for DAC-based CO_2 capture, reflecting lack of data and experience from large-scale plants. However, a recent expert solicitation suggests for 2030 an average capture cost interval of USD 400-670/t CO_2.

Figure 4.4 Levelised cost of e-ammonia and e-methanol at different capture cost for CO_2 feedstock



Notes: CO_2 capture costs USD 30/t CO_2 from high-concentration sources, USD 80/t CO_2 from flue gases, USD 400/t CO_2 from direct air capture. All other assumptions are for 2030. Financial: WACC 5%, economic life 25 years. Performance (all in LHV): electrolyser 69%, H_2-to-ammonia 88%, H_2-to-methanol 80%, ammonia and methanol synthesis minimum load 30%, electricity consumption of compression and ASU for ammonia plant 500 kWh/t, electricity consumption of compression and distillation for methanol plant 1 100 kWh/t. CAPEX: solar PV USD 690/kW, wind onshore USD 1 160/kW, electrolyser USD 800/kW_e, H_2 storage USD 400/kg, ASU + ammonia synthesis loop USD 700/kW_e, methanol synthesis loop + distillation USD 700/kW_e. OPEX: onshore wind USD 10/MWh (today and 2030), solar PV USD 10/MWh (today), USD 5/MWh (2030), electrolysis 1.5%/yr of CAPEX, synthesis 3%/yr of CAPEX. Consumables: water USD 2/m^3, CO_2 feedstock USD 30/t. No value assumed for by-product heat.

The cost of CO_2 feedstock plays an important role in the cost of low-emission e-fuels, and especially in the relative competitiveness between e-ammonia and e-methanol. When e-methanol production can be based on a high-concentration CO_2 source, it is around 25% more expensive to produce than e-ammonia. However, post-combustion capture from biogenic flue gases increases the cost difference to 40%. Finally, if CO_2 would need to be sourced directly from air, it would make low-emission e-methanol more than twice as expensive to produce as e-ammonia.

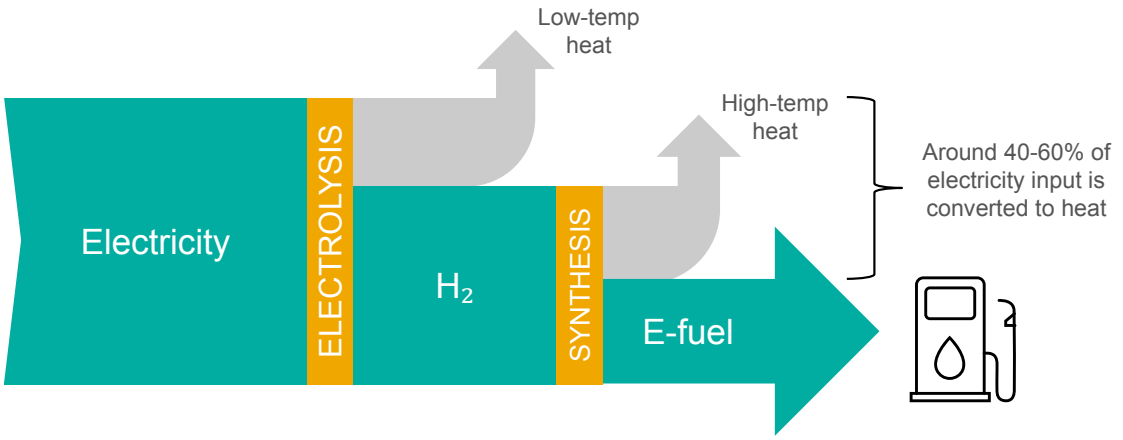
The need to source CO_2 for carbon-containing low-emission e-fuels from biogenic point sources will also limit the scale of production. Large corn ethanol plants generate around 1 Mt of by-product CO_2 annually, enough feedstock for around 1 GW_e scale e-fuels plant. However, large-scale biomethane plants are much smaller in comparison, producing less than 5% of the CO_2 volume of a large ethanol plant, significantly restricting the scale of e-fuels production (to around 50 MW_e). However, several fermentation and biomethane plants could be connected with a common pipeline infrastructure that would allow production of e-fuels at a much larger scale from biogenic CO_2.

In contrast to point sources, DAC plants could provide CO_2 at a scale that is constrained only by the amount of available land for building the capture units. With DAC, e-fuel plants can be also sited independently from point sources, only based on the quality of renewable resources and availability of land for large-scale project development.

Heat integration

Large-scale commercial electrolysers operate today at efficiencies of 65-70% on a lower heating value (LHV) basis while the downstream synthesis step needed for the e-fuels process is 65-85% (LHV) efficient depending on the end product. As a result, the overall thermal efficiency from electricity to fuels ranges from 40-60%.

Figure 4.5 Schematic energy balance of an e-fuels process



Conversion losses from e-fuels production are released in the form of heat and can be utilised for various purposes. From electrolysis, by-product heat can be recovered at around 70-85°C, suitable for use in drying and space heating purposes.

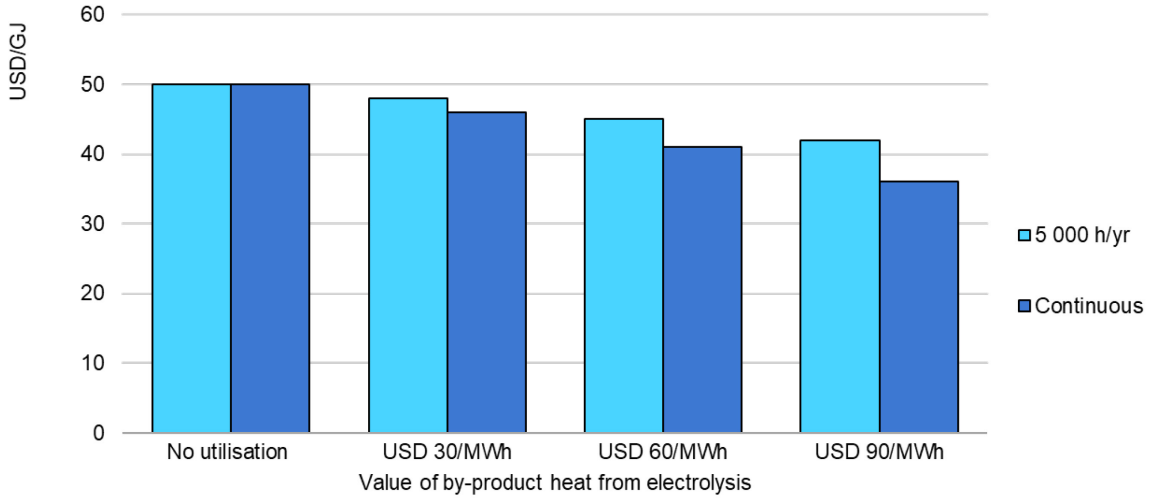
By-product heat from the synthesis step is released at significantly higher 200-300°C temperature level and can be used to produce steam for various purposes.

If by-product heat from electrolysis can be fully monetised, it could provide a significant additional low-emission revenue stream. At a USD 60/MWh value for by-product heat, the levelised cost of e-fuels would be reduced by around USD 10/GJ.

Heat released by large-scale production of e-fuels may be difficult to monetise entirely, as local heat demand may not match the scale of heat generation nor the variable operating patterns of the e-fuels plant. However, hot water storage facilities are available at a relatively low cost and are used commercially in district heating networks. By contrast, low temperature heat cannot be economically transferred for very long distances, so e-fuel plants should be located relatively near the heat demand.

Space heating demand for buildings is seasonal and limited to 2 500-5 500 hours per year depending on the region. Industrial heat demand, however, is generally more evenly spread across the year, offering significant potential for by-product heat utilisation.

Figure 4.6 Levelised cost of e-kerosene by value of electrolyser's by-product heat and duration of demand



Note: Electrolyser 69% (LHV), heat derived at 70-85°C temperature. Heat output 38 MJ/kg H_2.

While heavy industries typically require high temperatures, a quarter of industrial heat demand is needed at a temperature level below 100°C. Such processes include drying, washing, pickling, staining, tempering and many others, with typical applications in sub-sectors such as paper, food and beverages, textiles or wood industries. Heat recovered from electrolysis can also be upgraded with heat

pumps or used for preheating higher temperature industrial processes. Opportunities to valorise recovered heat through industrial processes depends on the possibility to operate them flexibly, or to invest in heat storage to buffer the variability of heat generation from the e-fuel plant.

High-temperature heat from the synthesis can be utilised also to cover e-fuel plant's own heat requirements. For example, in methanol production heat can be used to drive distillation units that separate water from raw methanol to meet methanol quality standards. Another possibility is to supply heat for the CO_2 capture units or steam to high-temperature electrolysers.

In addition to heat, high purity oxygen is also produced in large quantities as a co-product to hydrogen in electrolysis. Oxygen is used in many industrial uses, such as in the medical, food, metal and pulp sectors, and part of this could be captured by selling by-product oxygen from e-fuel plants, although the market is small compared to the amount of oxygen that would be released as a side effect of a large-scale production of e-fuels.

Innovation

Although the production of low-emission e-fuels can be based largely on commercial components, there exists still considerable potential to reduce costs through innovation. Areas for improvement cover topics from efficiency improvements to new synthesis pathways and to deeper integration with biofuels production.

Electrolyser efficiency

The largest efficiency losses in the e-fuel process occur during electrolysis where around 35% of the electrical energy is lost to low-temperature heat. Electrolyser efficiency is closely dependent on system design and optimisation goals. Alkaline systems that were deployed in the fertiliser and chlorine industries since decades ago were already optimised for high efficiency under continuous operation. However, efficiency improvements have continued since, focusing especially on lower cost systems using high current densities, on achieving higher efficiency across the load curve, and on minimising voltage degradation over time. Continuous improvements have the potential to increase average electrical efficiencies[7] of low-temperature electrolysers on average from 65% to 69% by 2030.

[7] Electrolyser's electrical efficiency is the chemical energy content of the produced hydrogen (based on lower heating value), divided by the electrical energy input of the electrolyser. For SOEC electrolysers electrical efficiency does not include the energy for steam generation.

In parallel with continuous improvements of alkaline and PEM electrolysers, a scale up of high-temperature solid oxide (SOEC) technologies would enable a step change in electrolyser efficiency. SOEC electrolysers can achieve electrical efficiencies around 90% (LHV), but they operate at about 850°C, which means that feedstock water needs to be supplied in the form of steam. High efficiency of SOEC electrolysers is partly based on the assumption that electricity is not needed to produce steam, but instead it is available for the electrolysis from external sources. Using by-product heat from the fuel synthesis to generate steam for the electrolysers would therefore provide obvious benefits to boost overall system efficiency, with first projects being announced. Especially the large amount of by-product heat output made available from the FT synthesis would provide significant opportunities for thermal integration with SOEC electrolysers.

Preparation of syngas from CO_2 for FT synthesis

The FT reaction requires carbon monoxide (CO) as reactant instead of CO_2. Therefore, in e-fuel applications a conversion step from CO_2 to CO is needed before the conventional FT synthesis. This can be achieved by catalysing water-gas shift (WGS) reaction in reverse. Several alternative process configurations can be envisioned for the preparation of syngas from CO_2 for FT, depending on how the reactor would be heated and how it would be integrated with the overall process. An alternative approach also exists, as syngas could be prepared directly in a high-temperature co-electrolysis of CO_2 and H_2. This would eliminate the need of a separate reverse-WGS step.

New pathways to e-kerosene

The methanol-to-gasoline (MTG) process was developed in the 1970s as a complementary route to Fischer-Tropsch for producing synthetic fuels. Both processes enable the production of liquid hydrocarbons from carbonaceous feedstocks that can be used as drop-in replacements for conventional petroleum fuels. Later in the 1980s a spin-off process was developed for producing light olefins from methanol (MTO).

In contrast to the FT process that produces hydrocarbons at a wide carbon number range, gasoline synthesis is very selective, producing primarily a finished gasoline blend stock and a by-product stream resembling liquefied petroleum gas (LPG). A direct route to synthetic gasoline that avoids the separate methanol production step, called the TIGAS process, has also been developed.

There is renewed interest towards producing synthetic hydrocarbons from methanol, especially jet fuel. Given the prior experience acquired from the methanol and gasoline/olefin technologies, a new route to e-kerosene utilising

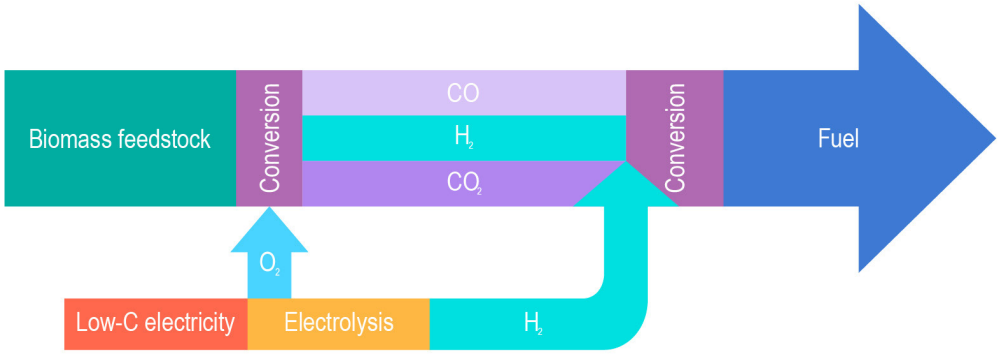
methanol as an intermediate could emerge quickly and first demonstrations are already being announced.

Integration with biomass gasification

Clear synergies exist between the biofuel and e-fuel routes, most obviously via the utilisation of biogenic CO_2 as a feedstock for low-emission e-fuels. However, opportunities exist also for a deeper integration, especially through combining the e-fuels route with the production of synthetic biofuels to a hybrid "e-biofuels" process.

The production of synthetic biofuels involves gasification of lignocellulosic biomass to produce synthesis gas that is further converted to fuels by a catalytic synthesis. The CO_2 that is formed during gasification needs to be removed from the process as there is not enough hydrogen in the system to convert it into fuel. However, if the process is supplemented with an external hydrogen source, this carbon can be converted to fuel instead of being removed. Such an e-biofuels approach can significantly increase the fuel yield and therefore the carbon efficiency of the biofuel process. With a fully integrated process, the amount of fuels that can be produced from a given amount of biomass can be more than doubled.

Figure 4.7 Schematic illustration of an integrated e-biofuels process combining elements from biomass gasification and e-fuels pathways



Notes: The first conversion involves biomass gasification and clean-up of the produced syngas with catalytic reforming. The second conversion involves fuel synthesis. Oxygen needs of the gasification and reforming step can be supplied from the by-product oxygen of the electrolysis.
Source: Hannula, I. (2016), Hydrogen enhancement potential of synthetic biofuels manufacture in the European context: A techno-economic assessment, *Energy*, Vol. 101, pp. 380-389, https://doi.org/10.1016/j.energy.2016.03.119.

In addition to an improved yield, cost benefits can also be identified. By-product oxygen from electrolysis can be used to supply process' oxygen requirements, avoiding the need to invest in a cryogenic air separation unit. By-product heat from electrolysis can be used for drying the biomass residues before gasification. Cost savings can be achieved also by omitting the need to invest in a CO_2 removal unit. In addition, the electrolyser unit could be operated flexibly alongside the biofuels plant, depending on the cost of low-emission electricity.

Chapter 5. Deployment analysis

If low-emission e-fuels are to make a meaningful contribution to reducing emissions from transport, a rapid scale up is needed during this decade. This chapter assesses the implications in terms of needed cost reductions and infrastructure investments of an assumed ambitious goal of achieving a 10% share of e-fuels in aviation and shipping by 2030.

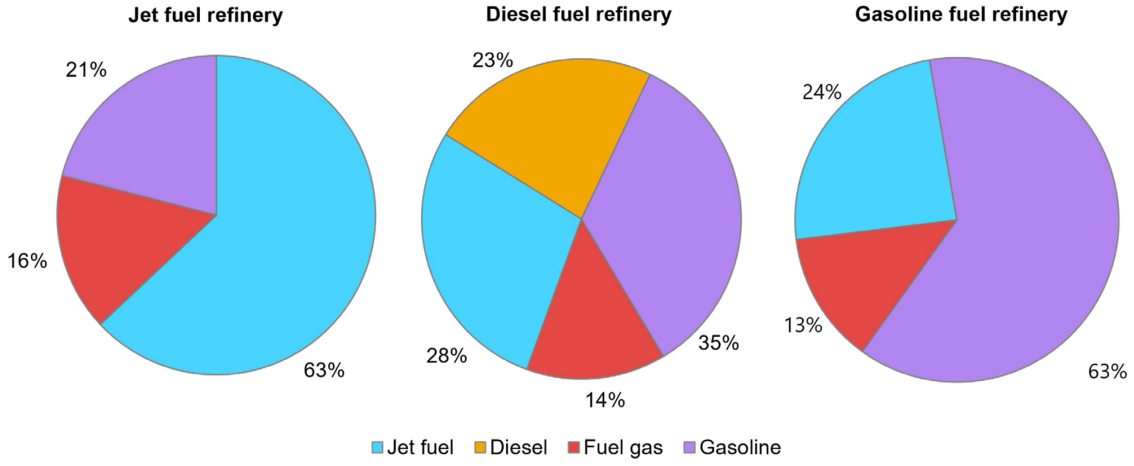
10% e-fuels for aviation

In 2022, aviation accounted for 2% of global energy-related CO_2 emissions, having grown faster in recent decades than rail, road or shipping. As international travel demand recovers following the Covid-19 pandemic, aviation emissions in 2022 reached almost 800 Mt CO_2, about 80% of the pre-pandemic level. Based on current policies, aviation fuel demand would reach 15 EJ (7 500 kb/d) by 2030. Achieving 10% share of e-fuels would therefore require 1.5 EJ (750 kb/d) of e-kerosene, which can be produced via the Fischer-Tropsch (FT) route.

The FT process was first discovered in the 1920s and was initially used to derive liquid fuels from coal. Today natural gas has largely replaced coal as a preferred feedstock for new plants, owing to its higher hydrogen content, better efficiency, and fewer impurities, although China has recently seen a resurgence of coal-to-liquids plants.

The Fischer-Tropsch process involves reacting synthesis gas over a catalyst to produce synthetic crude oil (syncrude) in a reactor operating at around 200°C and 20-30 bar. Of the most common catalyst metals for the FT process (iron, cobalt, nickel and ruthenium), iron and cobalt are available today for industrial application. Syncrude – like conventional crude oil – needs to be refined to obtain usable transport fuels. Several different FT refinery designs have been proposed to maximise the production of either aviation fuel, high cetane diesel or synthetic motorgasoline. However, none of these fuels can be produced with perfect selectivity. From a refinery that is optimised for jet fuel production, around 75% selectivity to on-specification kerosene can be achieved, the remaining 25% of transport fuel components being in the form of synthetic gasoline. This means that from 1.5 EJ e-kerosene supply in 2030, around 0.5 EJ of e-gasoline would be produced as a by-product.

Figure 5.1 Selected Fischer-Tropsch product distributions to on-specification jet fuel, diesel and gasoline by refinery design



Note: With FT refinery designs, a combined transport fuel mass yield of 85% can be achieved with fuel gas (mostly light hydrocarbons such as methane and ethane) being the main non-transport fuel component.

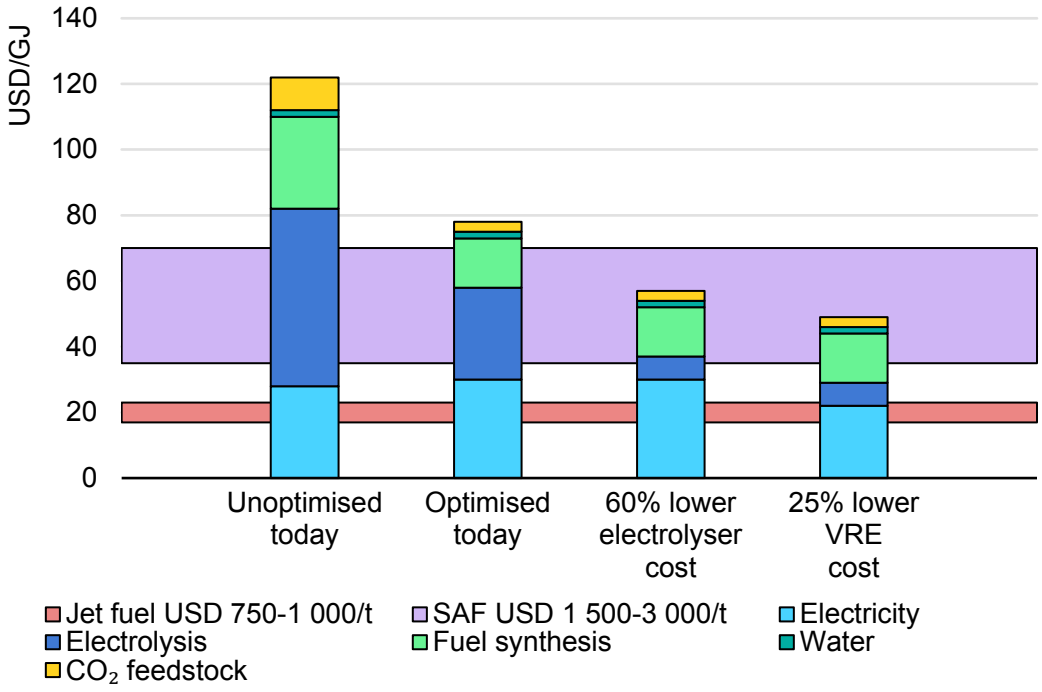
Source: IEA based on Fischer-Tropsch Refining, © University of Pretoria.

Refinery designs illustrated in Figure 5.1 aim to maximise overall transport yield (e.g. combined amount of jet fuel and gasoline). These limits could be surpassed in a refinery by forcing the product distribution further towards a single product. Even a 100% jet fuel refinery would be possible if all non-jet fuel products would be continuously recycled and converted back to syngas. However, this would lead to lower overall efficiency and require much more refining (increasing capital and operating costs) compared to a design where by-product gasoline is allowed.

Cost impact

The current high cost of low-emission e-kerosene is a key barrier for its deployment. An optimised large-scale plant, located on a site with high-quality solar PV and wind resources with complementary profiles, and having access to low-cost biogenic CO_2 feedstock, could produce e-kerosene at a cost of USD 80/GJ (USD 3 500/t), around 4-5 times the price of conventional jet fuel today (USD 750-1 000/t). With a 60% reduction in the price of electrolysers by 2030, the cost of e-kerosene could be reduced to USD 60/GJ. Assuming further a 25% reduction in the price of renewable electricity, the levelised cost of e-kerosene could be reduced to USD 50/GJ (USD 2 150/t) by 2030.

Figure 5.2 Levelised cost of e-kerosene by potential cost reduction measure



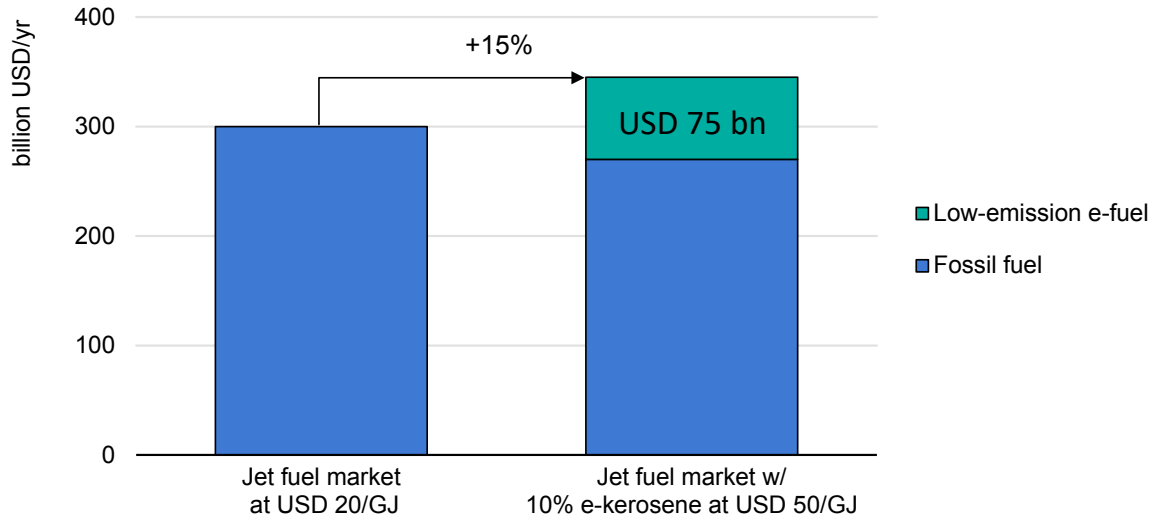
Notes: The example features an e-kerosene plant based in US Midwest with 18% capacity factor for solar PV and 44% for onshore wind. Financial: WACC 5%, economic life 25 years. Performance (all in LHV): electrolyser 65% (today), 69% (2030); H_2-to-syncrude 57%, transport fuel mass yield from FT jet fuel refinery 85%, FT synthesis minimum load 30%, electricity consumption of compression and refining 540 kWh/t. CAPEX: solar PV USD 1 120/kW (today), USD 690/kW (2030), wind onshore USD 1220/kW (today), USD 1 160/kW (2030), electrolyser USD 2 000/kW_e (today), USD 800/kW_e (2030); H_2 storage USD 400/kg, RWGS + FT synthesis + refinery USD 1 200/kW_e. OPEX: onshore wind USD 10/MWh (today and 2030), solar PV USD 10/MWh (today), USD 5/MWh (2030), electrolysis 1.5%/yr of CAPEX, synthesis 3%/yr of CAPEX. Consumables: water USD 2/m^3, CO_2 feedstock USD 30/t. Value of e-gasoline by-product assumed equal to e-kerosene. No value assumed for by-product heat. Weather data from Renewables.ninja.

Even at USD 50/GJ, e-kerosene would still remain 2-3 times more expensive than conventional jet fuel today, although it would start to be able to compete with current biomass-based SAF prices (USD 1 500-3 000/t). Despite the high cost of low-emission e-kerosene, its total impact on the aviation sector would be moderated by the small 10% share. Assuming a USD 20/GJ price for fossil jet fuel, a 10% e-kerosene blend would increase the overall fuel cost of the aviation sector by USD 75 billion, or by 15%.

The impact to consumers would depend on how the cost increase would be distributed. If costs would be passed equally to all customers, around 5% increase in ticket prices could be expected, considering that fuel price usually represents 25-30% of total flight costs. Recent experiences suggest that consumer demand for air travel is resilient to higher prices. For major OECD economies, jet fuel price elasticities are about -0.02/-0.03 (a 1% price increase will lead to a 0.02% reduction in airline jet fuel demand). For emerging markets, price elasticities tend to be somewhat higher, typically -0.04/-0.05.

Airlines, rather than allocate these extra costs pro rata, may also decide to skew their pass-through to more expensive customer segments, such as business class. Here travellers tend to give priority to the overall high-end travel experience and correspondingly putting a smaller weight on price. This results in a demand elasticity that is lower than for cheaper booking classes, so that raising fares here will have a relatively minor impact on airline revenues.

Figure 5.3 Impact of 10% share of e-fuel in the aviation markets



This low elasticity occurs for a number of reasons. Firstly, risk management through price hedging in the derivatives market, while not universal, is very common among airlines. This dampens the impact of oil price volatility on their profit and loss statements, thereby rendering their fuel purchases less price sensitive. Secondly, the residual price risk that (if not absorbed) is passed on to end customers, is unlikely to have a large impact on travel demand. This is because jet fuel differs fundamentally from other transport fuels such as gasoline and diesel, where consumers are confronted continuously with market pump prices. Conversely, consumer exposure to jet fuel prices is partial, indirect and opaque, resulting in a low-price elasticity. As a rough estimate, a 5% overall increase in ticket prices as calculated above would reduce travel demand by about 0.5-0.8%.[8]

[8] This is a simplification: price elasticities differ according to type of travel (higher for leisure vs business), distance (higher for short haul vs long haul) and region (higher for developing nations vs developed countries). Also, global trends with regard

Rather than price, income is more important as a driver of the demand for air travel, as this is largely determined by the spending capacity of its consumers. This is especially true in emerging market countries, where air travel is perceived as a luxury good, an income/wealth elasticity effect will dominate the impact of price changes.

Distribution and end use

Jet fuel demand is fairly evenly spread between world regions, but at a local level its use is typically extremely concentrated. By 2030, about 40% of consumption is expected to take place in the Asia Pacific region, about 25% in North America and slightly less than 20% in Europe. Europe and the United States account for a substantial share of future e-kerosene projects and it should be feasible, subject to blending constraints, to place a large share of the slated 10% of global demand into these markets.

Large aviation hubs serve as major foci for demand, resulting in comparably simple distribution networks for fuel suppliers. This is something that oil refiners currently benefit from and connections to these sites will be important for producers of e-kerosene in the future. Based on the distribution of relevant projects, similar opportunities may exist, especially in Western Europe. Furthermore, the use of a book-and-claim system, where the site of consumption could be better aligned to regions with lower cost of e-kerosene production, would help to optimise this geographical distribution.

Depending on how blending of existing and e-kerosene fuel will be managed, this might imply additional requirements on storage and handling capabilities for distributors. However, in part these would be dependent on the way in which novel fuels were used and certified, and for larger hubs this is unlikely to form a major obstacle.

Blending e-fuels into existing fuel pools requires minimising the risks of incompatibility between the relevant fuel molecules but also ensuring that the new compositions are compatible with the overall fuel and emissions specifications for a product. Similarly, energy density, low emissions (CO_2, particulates, nitrogen oxides [NO_x], etc.), miscibility, stability, volatility, cold properties, lubricity, fluidity and handling properties are all important considerations.

The new fuels must also be compatible with existing engines (no degradation in performance or safety) as well as adapted to future engine designs. This

to geopolitics and health are paramount – the reopening of economies from pandemic-related lockdowns saw a massive release of pent-up travel demand, with passengers looking to fly whatever the cost.

generally requires extensive bench testing and initial blending in low volumes (a few percent and up to 10%). The latter is favoured in any case by the limited availability of the fuels today.

In the case of e-kerosene, questions around compatibility and blending can be addressed by adherence to ASTM standards (D7566 Annex A1 and Annex A5 or D1655). Blending with at least 50% conventional jet fuel is required to meet these rules. Particular concerns exist around the way synthetic kerosene interacts with seals within aircraft engines. If the aromatic content of the fuel is too low, this can result in a density below minimum requirements and seal shrinkage. Resulting seal failures in the engine can cause fuel to leak damaging the system. Using at least 50% conventional fuel ensures sufficient aromatic content (at least 8%) to maintain elastomer compatibility.

If e-fuel properties and characteristics are comparable with the related conventional fossil-derived fuels, an e-fuel or e-fuel blend can be deemed equivalent to the conventional fuel and is referred to as a drop-in fuel. On this basis, it could be seamlessly integrated into the fuel delivery infrastructure without the need for separate tracking or regulatory approval; in other words, the fuel would be fully fungible. This requires a rigorous evaluation process for candidate fuel and producers.

Product specifications can change by region and by season. For e-fuels replacing gasoline, their volatility must increase in cold weather and decrease in hot temperatures, in the same way as for their fossil equivalents. It must also decrease in zones with a high risk of ozone formation. Producers would need to bring the octane rating for e-gasoline, which might otherwise be relatively paraffinic, up to the levels of their fossil counterparts. For e-fuels replacing diesel, cloud point of the fuels must be compatible with the seasonal climate changes (lower in winter than summer) while the cloud point for e-kerosene must meet the international standards.

Uptake of e-gasoline by-product

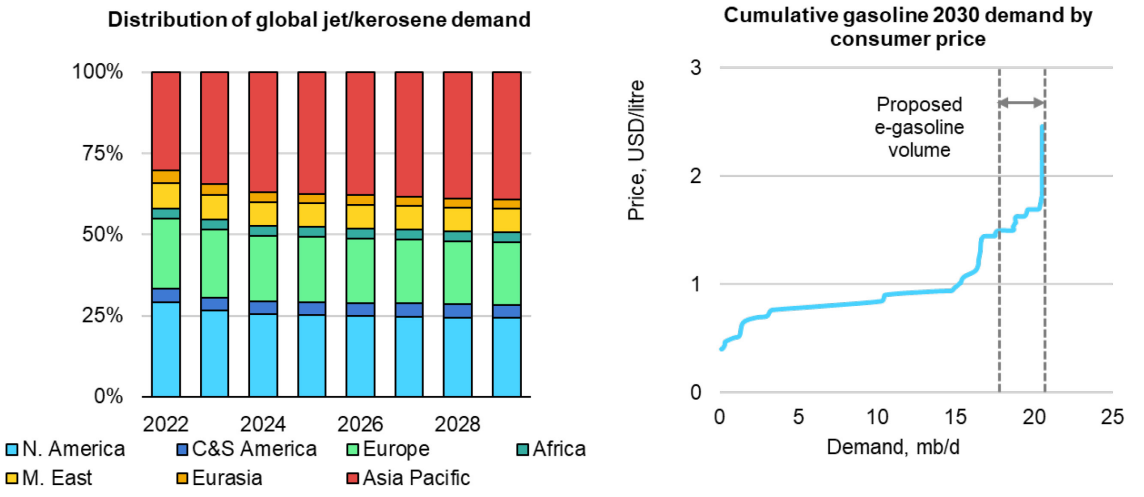
The production of 10% share of e-kerosene in aviation by 2030 creates the related need of marketing and distributing annually 0.5 EJ (roughly 250 kb/d) of e-gasoline co-product. While a large quantity of fuel, it represents only 1% of global gasoline consumption (48 EJ, 24.5 mb/d in 2030). In comparison, the total contribution of bioethanol to the gasoline pool is expected to reach 2.6 EJ in 2030, meaning that e-gasoline's contribution would be about 20% of this volume.

Given the important role of e-gasoline as a by-product of e-kerosene, its average value has a significant impact on the overall economics of the FT process. However, this could be analogous to the treatment of biofuels, especially biodiesel and renewable diesel. In these cases, greenhouse gas targets and blending

mandates will play an important role in price discovery. Similarly, exemptions on taxes and duties would help to condition overall uptake. Existing policies for the use of e-fuels are heavily concentrated in OECD countries, and these are also often the locations with the highest gasoline pump prices.

While OECD gasoline demand will have entered a structural decline by 2030, these economies will still account for 47% of global consumption, meaning that it should be possible to absorb the relatively small volumes of e-gasoline under discussion. Target countries for e-gasoline could be those with the highest projected pump prices in 2030. For this purpose, global gasoline demand has been ranked according to the expected 2030 price paid by drivers in each country. These retail price forecasts have been created using both current forward pricing in the wholesale gasoline market, and the historical relationship between these wholesale prices and a given country's pump prices. Starting with a hypothetical maximum e-gasoline uptake of 10% of total demand and the highest cost countries, the 0.5 EJ of e-gasoline could be accommodated primarily within European and Japanese markets. Additional uptake from other regions, especially North America, would ease this further. A high-quality gasoline adapted to the aviation fuels market (avgas) would also allow the fuel to be sold at a premium.

Figure 5.4 Jet fuel demand and end-user gasoline price distribution



E-gasoline is likely to benefit from the portfolio of market instruments, infrastructure and incentives that exist for biofuels, especially with respect to bio- and renewable diesel. However, in those markets where these are formulated in terms similar to emissions targets, and apply on a company level, this is likely to create competition between the various alternative fuels. Price discovery for the biofuels and e-fuels might therefore become closely related, with relative prices

influenced by respective carbon intensity ratings. This highlights the importance of a globally-accepted framework for evaluating life-cycle emissions of e-fuels.

10% e-fuels for shipping

In 2022, international shipping accounted for about 2% of global energy-related CO_2 emissions. Historically, oil products have constituted over 99% of total energy demand for international shipping, with LNG and biofuels only meeting a marginal share. Based on current policies, total marine fuel demand is projected to reach 13 EJ (5.5 mb/d) by 2030. To produce a 10% share of e-fuels in the marine sector, an estimated 1.3 EJ (70 Mt/yr) of either e-ammonia or e-methanol would be needed. This is 3.5 times the current global traded volume of ammonia or two times the traded volume of methanol. Unlike with e-kerosene, no other fuels are obtained as a by-product.

Ammonia can be produced via the Haber-Bosch ammonia synthesis by reacting a hydrogen-nitrogen mixture over an iron catalyst at 400-500°C temperature and high operating pressure above 100 bar. The world's first ammonia plant was commissioned already in 1913 and modern plants still retain the same basic configuration. Nitrogen needed for the synthesis is acquired directly from air where it is available at high (78 vol%) concentration. For the e-ammonia process, this can be achieved using a cryogenic air separation unit (ASU).

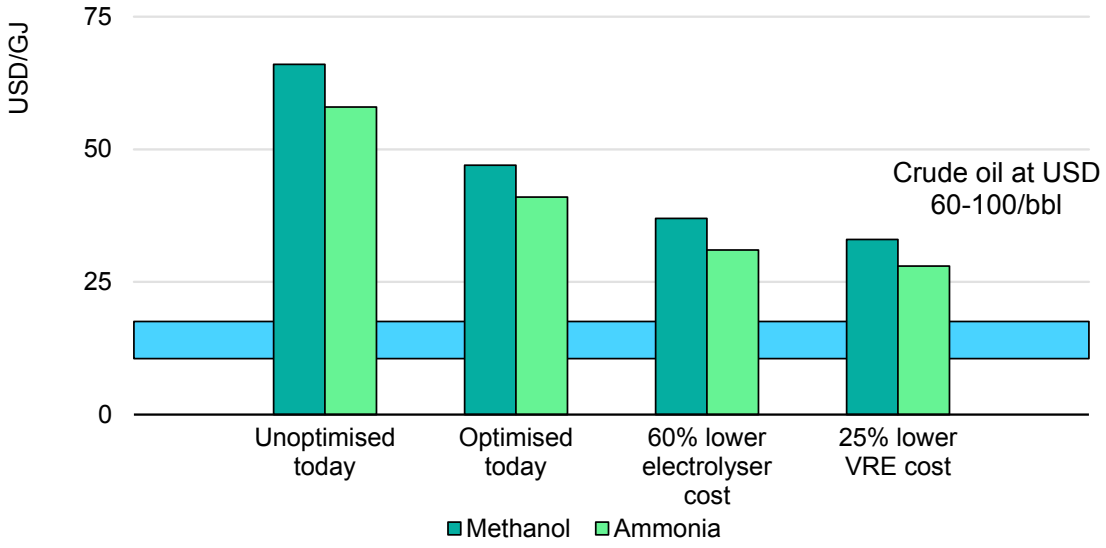
Methanol was first produced from synthesis gas in 1923, benefitting from the engineering know-how acquired from the prior development of ammonia synthesis technology. Today, industrial-scale production is based on reacting synthesis gas over copper-based catalyst at 250-280°C and 60-80 bar using syngas produced mainly from natural gas. Methanol can be produced with modern catalysts at over 99.9% selectivity. Unlike in the conventional methanol process that uses carbon monoxide (CO) as a carbon source, the e-methanol process is based on directly hydrogenating CO_2 to methanol. Optimised processes for this application are already offered commercially. The produced raw methanol contains water that is formed as a by-product of CO_2 conversion, and which needs to be largely removed by distillation to meet methanol quality standards. The e-methanol route from CO_2 results in much higher level of water formation that needs to be considered in the process design.

Cost impact

While cheaper to produce than low-emission e-kerosene, low-emission e-ammonia and e-methanol are both high-cost fuels today. An optimised large-scale plant, located on a site with high-quality renewable resources and low-cost biogenic CO_2 (only for e-methanol), could produce low-emission e-methanol today at a cost of USD 47/GJ and low-emission e-ammonia at USD 40/GJ. However,

with anticipated reductions in the price of electrolysers and renewable electricity, the levelised cost of low-emission e-methanol could reach USD 35/GJ and of e-ammonia USD 30/GJ by 2030. Reaching this cost level would make low-emission e-ammonia and e-methanol cost comparable with the higher end of fossil methanol and ammonia prices over the 2010-2020 period as a chemical commodity, and open a door for their use as a low-emission fuels for shipping.

Figure 5.5 Levelised cost of e-ammonia and e-methanol by potential cost reduction measure



Notes: The example features e-ammonia and e-methanol plants based in US Midwest with 18% capacity factor for solar PV and 44% for onshore wind. Performance (all in LHV): Electrolyser 65% (today), 69% (2030); H_2-to-ammonia 88%, H_2-to-methanol 80%, ammonia and methanol synthesis minimum load 30%, electricity consumption of compression and ASU for ammonia plant 500 kWh/t, electricity consumption of compression and distillation for methanol plant 1 100 kWh/t. CAPEX: solar PV USD 1 120/kW (today), USD 690/kW (2030), wind onshore USD 1 220/kW (today), USD 1 160/kW (2030), electrolyser USD 2 000/kW_e (today), USD 800/kW_e (2030); H_2 storage USD 400/kg, ASU + ammonia synthesis loop USD 700/kW_e, methanol synthesis loop + distillation USD 700/kW_e. OPEX: onshore wind USD 10/MWh (today and 2030), solar PV USD 10/MWh (today), USD 5/MWh (2030), electrolysis 1.5%/yr of CAPEX, synthesis 3%/yr of CAPEX. Consumables: water USD 2/m^3, CO_2 feedstock USD 30/t. No value assumed for by-product heat. Weather data from Renewables.ninja.

Unlike in aviation where e-fuels offer a drop-in solution to decarbonisation in the form of kerosene, achieving 10% share of e-fuels in the marine sector by 2030 would not only require an accelerated deployment of e-fuels, but also – as ammonia and methanol are alternative fuels – significant investments in distribution, bunkering, and vessels (either conversions or new builds) to enable their use.

The marine sector combines various types and sizes of vessels with different average journey lengths. Today, containerships represent around 25% of the total energy consumption of the sector, oil/gas/chemical tankers about 25%, bulk carriers over 20%, passenger/fishing/service boats 15% and other merchant ships less than 15%.

Among large ocean-going vessel types, containerships are potential candidates for early low-emission e-fuel adoption. Their typical voyage lasts for several weeks, making them especially hard to electrify. They also transport the most valuable type of cargo, so an increase shipping costs has the lowest impact on the value of the transported goods. However, in order to use ammonia or methanol, 2-stroke-cycle internal combustion engines (ICE) that are commonly used in large ocean-going vessels need to be modified. Methanol engines are already available and are slightly more expensive than engines running on heavy fuel oil (HFO). Ammonia engines are currently in the final stages of development and large 2-stroke engines are expected to become commercially available in 2025. They are estimated to be around 30% more expensive than conventional engines.

On-ship storage tanks also need to be modified to accommodate alternative fuels. Methanol requires 2.5 times the volume of marine gasoil (MGO) for the same energy content. For ammonia, the tanks need to be resistant to corrosion and over three times larger than for MGO, taking into account the need for cryogenic equipment to keep the temperature below -33°C. The need for larger tanks also has an indirect impact on costs through reduced space available for cargo.

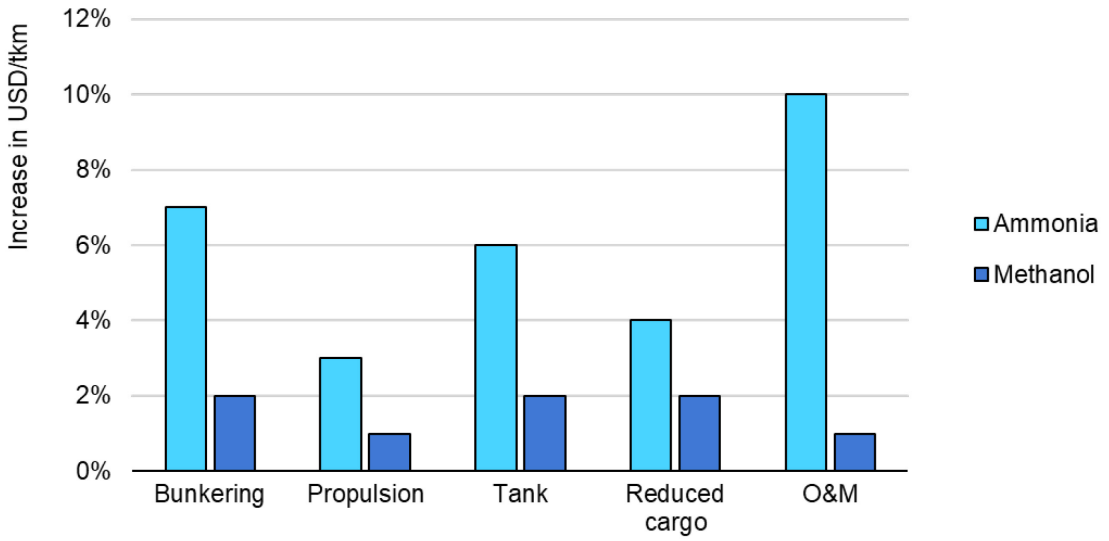
As far as safety is concerned, methanol is highly flammable and toxic, and specific features should be included in the design of the ship, such as location, inert gas blanketing and venting of the tanks, spill containment, vapour detection and firefighting systems. These are currently covered in the IMO's "Interim Guidelines for the Safety of Ships Using Methyl/Ethyl Alcohol as Fuel" (MSC.1/Circ.1621).

Ammonia is less flammable than methanol, but toxic at a much lower concentration. This puts more pressure on the safety design features of the ship, including location of the tanks, double piping, leak detectors, and dedicated ventilation systems. For the same reasons, a skilled crew is also needed, leading to increased operating costs. The IGF code[9] regulating ships using low-flash-point fuels does not currently provide the necessary specific requirements to cover ammonia as a fuel. In addition, the IGC code[10] governing ships carrying liquefied gases in bulk currently prohibits the use of ammonia (toxic cargo) as a fuel. Both codes are in the process of being revised by the IMO and could enter into force in the coming years.

In addition, bunkering infrastructure needs to be developed to supply the new fuels. The same safety precautions that are needed for ammonia handling make it also more costly to bunker.

[9] International Code for Safety of Ships Using Gases or Other Low-flashpoint Fuels.
[10] International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk.

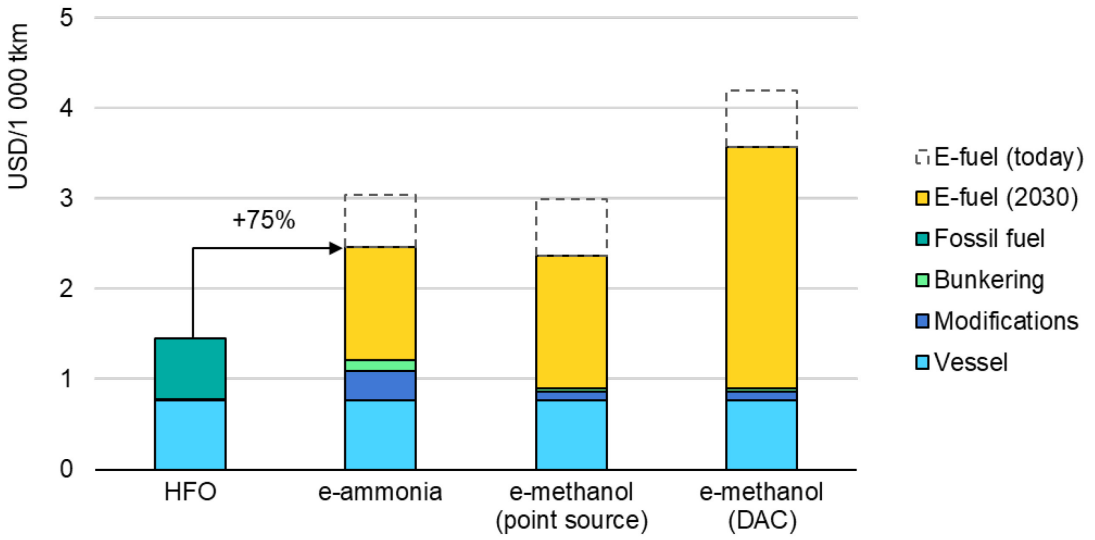
Figure 5.6 Estimated cost increases for ammonia and methanol containerships relative to conventional vessels operating on heavy fuel oil



Notes: 9 600 TEU containership, with a 58 MW engine, travelling at 16 knots, 100 000 nautical miles/yr.

Although e-ammonia is cheaper to produce than e-methanol, the vessel-related costs are higher for ammonia for all categories. To assess the overall impact of e-fuels on containerships, they should be evaluated on a total cost of ownership (TCO) basis. When accounting for the required vessel modifications, increased bunkering costs and the higher cost of e-fuels compared to HFO, the use of low-emission e-fuels in containerships would result in a 75% increase in total shipping costs per unit of activity (tonne kilometres) in 2030 (Figure 5.7). On a TCO basis the increase compared to HFO-fuelled containership is very similar for ammonia and methanol – the higher production cost of methanol being largely outweighed by the higher vessel-related costs of ammonia. However, this assumes that low-emission e-methanol can be produced from low-cost biogenic CO_2 point sources. If methanol production would rely instead on CO_2 captured from flue gases of biomass combustion plants or direct air capture, the overall cost of e-methanol would be clearly higher, almost tripling in the case of DAC compared to the conventional HFO-fuelled containership.

Figure 5.7 The total cost of ownership of a containership vessel by fuel



Notes: Modifications refer to the additional CAPEX and OPEX of the containership compared to the HFO reference. Port charges and handling fees are excluded. Assumptions: 9 600 TEU containership, with a 58 MW engine, travelling at 16 knots, 100 000 nautical miles/yr; Heavy fuel oil USD 15/GJ, levelised cost of ammonia USD 40/GJ (optimised today) USD 30/GJ (2030), levelised cost of methanol USD 47/GJ (optimised today) USD 35/GJ (2030, point source) USD 62/GJ (2030, DAC).

Despite the high increase in the total cost of ownership, the overall impact on shipping would be moderated by the high value of the transported goods. In total, around 165 million standardised containers, or a twenty-foot equivalent unit (TEU), are delivered annually. The ability to pass the costs along the value chain would depend on the terms of the shipping contracts, and on the existence of split incentives. If the added costs from low-emission e-ammonia (both fuel and infrastructure) would be fully allocated to customers (like the members of the Zero Emission Maritime Buyers Alliance), it would increase, on average, the shipping cost of one TEU by about USD 250. This increase can be compared to the typical container freight rate of USD 800-1 000/TEU according to UNCTAD, which includes not only the shipping costs themselves but also port charges and handling fees. The average value of goods transported in one container, which is typically between USD 30 000-60 000/TEU. In other words, a USD 250/TEU increase would represent less than 1% of the value of transported goods. For example, this would add less than one cent to the cost of an avocado or an iPhone and around USD 1.50 to a 2m x 1m solar panel module.

Vessel construction or conversion needs

In order to absorb the 10% share (1.3 EJ) of e-fuels in the marine sector, around 50% of the current containership fleet would need to be converted. This would represent around 12 million TEU of shipping capacity to be newly constructed or

retrofitted. Methanol ships are already commercially available, representing an estimated 0.8 million TEUs in current orderbooks.

The investment needed to convert an HFO ship to ammonia is roughly double the investment of converting it to methanol. As the cost of retrofitting needs to be amortized during the remaining the life of a vessel, only relatively new containerships would be suitable candidates for retrofitting. For ammonia conversions, the vessel would preferably be less than five years old (currently representing around 5 million TEU) while methanol conversions could include ships up to ten years old (currently around 12 million TEU). Considering that half of the eligible ships could be retrofitted, the remaining capacity needed to be newly built would be 9.5 million TEU in the case of ammonia and 6 million TEU in the case of methanol. Reaching the needed e-fuel-based transport capacity in the remaining six years up to 2030, would require constructing on average 1.6 million TEU/yr of new ships with ammonia, or 1 million TEU/yr of new ships with methanol. This would be slightly higher than the average construction speed of 1.2 million TEU/yr over the past decade, but less than the record 2.3 million TEU/yr planned for 2023.

In terms of investments, the conversion of the 12 million TEU of shipping capacity to operate on e-fuels would be around USD 75 billion for ammonia and USD 30 billion for methanol of additional spending compared to a HFO fleet (irrespective of the share of retrofits versus new ships). This would represent less than a 5% share of the cumulative shipbuilding market over the period of 2023-2030.

Ship bunkering infrastructure

In addition to containerships, specific storage and bunkering infrastructure would need to be developed to supply alternative fuels to the ships. Most of the demonstration projects today consist in refuelling ships that dock next to the ship to be refuelled to ensure maximum flexibility. Special considerations are needed for ammonia due to its toxicity when ports are located near a population centre. The incremental investment for bunkering infrastructures is expected to be in the order of USD 30 billion for ammonia and USD 10 billion for methanol.

While hundreds of ports provide maritime bunkering services, current activity is concentrated in a relatively small number of global hubs, such as Singapore, Rotterdam, Fujairah and Panama. Each of these hubs benefits from being strategically located at the heart of the world's key shipping lanes, rendering them natural ports of call for passing ship traffic. Singapore is the world's largest bunkering centre by far, thanks to its position at the southern tip of the Malay Peninsula. The Straits of Malacca, the world's busiest shipping lane and the shortest route between South Asia and East Asia, sees more than 100 000 vessel

transits per year. Singapore's bunkering volumes of 900 kb/d in 2022 were about four times as large as its nearest rival, Rotterdam. Amid a deep market for maritime logistic services with hundreds of competing suppliers, bunker fuels account for three-quarters of the city state's total oil demand.

Rotterdam, Europe's largest port, is the second largest bunkering hub, supplying about 200 kb/d to vessels (this increases to around 350 kb/d when considered for the entire Amsterdam Rotterdam Antwerp (ARA) port-industrial region). Recent years have seen Rotterdam consolidate its status, partly by making progress in supplying alternative fuels such as LNG, biofuels, and methanol. The Dutch port has established itself as the world's chief bunkering hub for biofuels, while ship-to-ship bunkering of methanol has already taken place several times. Singapore's first methanol bunkering operations were conducted in 2023.

Fujairah and Panama round off the list of principal bunkering centres, each supplying around 180 kb/d in bunker sales. Fujairah's location near the Strait of Hormuz (the world's most important oil transit point, used to ship 20 mb/d) makes it heavily dependent on oil tanker traffic. Higher, rerouted Russian trade flows to Asia have been counterbalanced by lower shipments from Saudi Arabia and other OPEC members in the wake of production cuts. Conversely, the Panama Canal is used mostly by containerships, with US containers representing about 70% of the waterway's traffic.

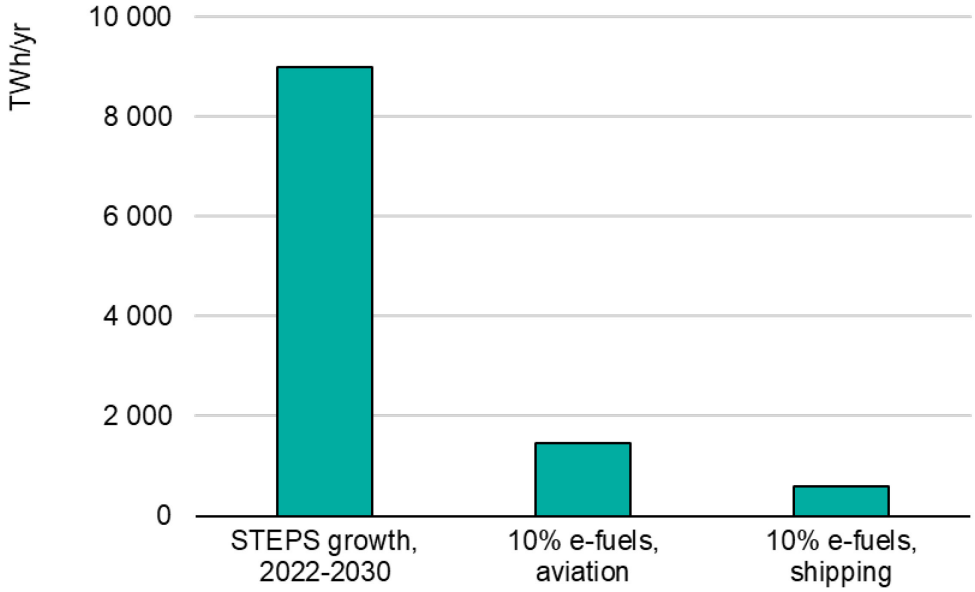
While no threat to Singapore, a number of other Asian ports such as Hong Kong and Busan, Korea operate as smaller regional centres. Among these, China's Zhoushan has in recent years emerged as Asia's fastest growing hub. Leveraging off its drive for economic self-sufficiency, Beijing has promoted Zhoushan as the country's premier bunkering hub through the establishment of a free trade zone and a range of tax incentives. Post Ukraine-invasion, surging shipments of cheap Russian crude have also boosted Zhoushan's bunkering activity, with total volumes now comparable to those at Fujairah and Panama.

Chapter 6. Resource requirements

Low-emission electricity

Electricity generation from low-emission sources is growing rapidly, driven by record expansion in solar PV and wind. Global renewable capacity additions are set to reach more than 440 GW in 2023. Together with nuclear and hydropower, low-emission electricity generation will grow by around 9 000 TWh between 2022 and 2030 in the Stated Policies Scenario (STEPS).

Figure 6.1 Growth of low-emission electricity generation in the STEPS (2022-2030) and electricity needs for achieving a 10% share of low-emission e-fuels in 2030 by transport sector



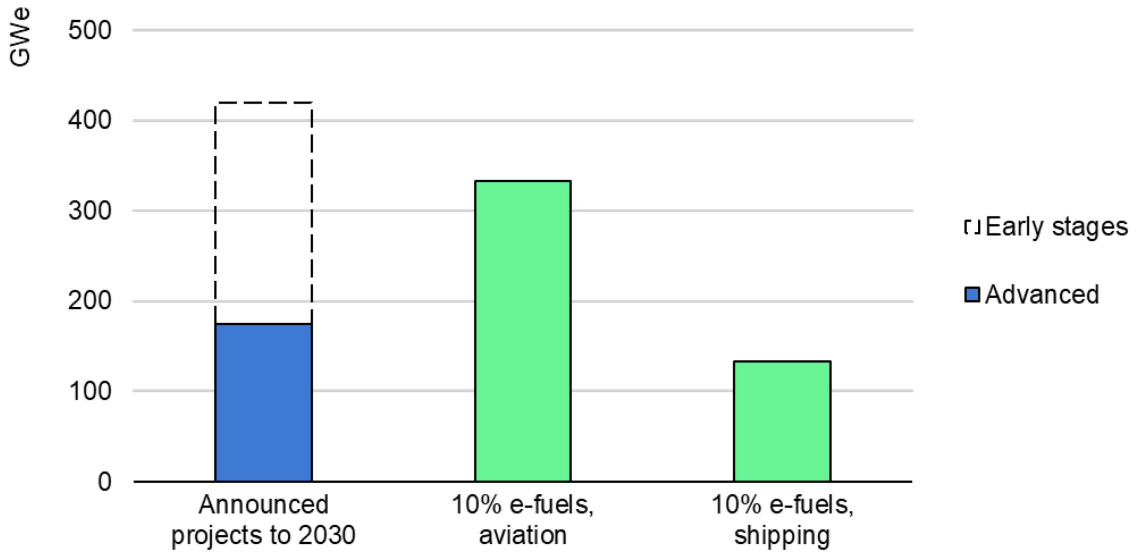
The amount of low-emission electricity generation needed to produce a 10% share of aviation fuels from e-kerosene is 1 500 TWh, with additional 600 TWh needed for a 10% share in shipping by 2030. The combined requirement of low-emission electricity is 2 100 TWh, which is equivalent to 23% of the global growth of low-emission electricity between 2022 and 2030 in the STEPS.

Electrolyser capacity

Based on announced projects in the IEA Hydrogen Projects Database, global installed electrolyser capacity could reach 175 GW by 2030. The capacity in 2030 increases to 420 GW when projects at early stages of development are also taken into consideration.

By the end of 2022, the available manufacturing capacity publicised by electrolyser manufacturers reached as high as 14 GW/yr, half of which was in China. However, based on company announcements, global electrolyser manufacturing capacity could reach 155 GW/yr by 2030, with one-quarter located in China, one-fifth each in the United States and Europe, and 6% in India.

Figure 6.2 Announced electrolyser projects to 2030 and electrolyser capacity needs for achieving a 10% share of low-emission e-fuels in 2030 by transport sector



Note: E-fuels for shipping assumed as e-ammonia. Average annual electrolyser load factor 50%.

The required electrolyser capacity needed to produce a 10% share of aviation fuel from e-kerosene is 330 GW_e, equivalent to 80% of global announced electrolyser projects to 2030. Due to higher efficiency of ammonia or methanol production and slightly lower fuel demand, electrolyser capacity required to meet 10% production of e-ammonia in marine transport would be 130 GW_e (150 GW_e for e-methanol) equal to roughly 30% of announced electrolyser projects. However, the required electrolyser capacity is strongly dependent on their annual average operational hours, being lower with higher load factors.

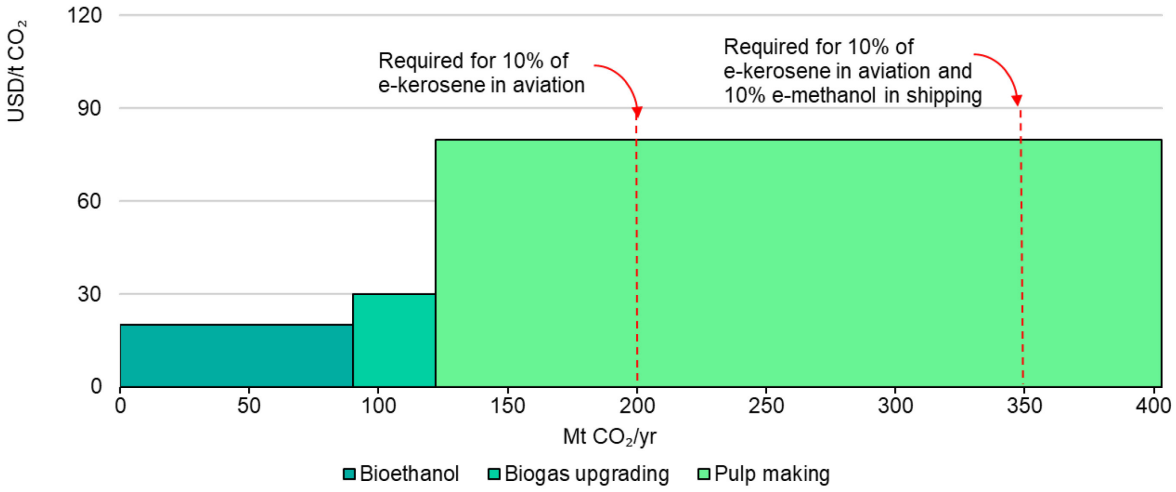
CO_2 feedstock

As discussed, the production of e-kerosene and e-methanol requires carbon in the form of CO_2. Around 2.5 Mt of biogenic CO_2 is currently being captured annually around the world, more than 90% of it from bioethanol plants. Around half of the captured gas is used, mainly in the food and beverage industry and for enhanced oil recovery, while the other half is stored underground. Biogenic CO_2 capture plants are concentrated in the United States, though some smaller-scale plants operate in Europe and Japan.

Bolstered by country-level net zero announcements and low-emission fuel strategies, the project pipeline for biogenic CO_2 capture has grown in recent years. Close to 40 Mt CO_2 could be captured in 2030, with around 65% from bioethanol and biodiesel plants and 35% from heat and power plants, according to publicly announced projects.

CO_2 utilisation would also open up opportunities for sites where underground storage of CO_2 would not be possible due to geology. For example, most ethanol plants in the United States are in the Midwest, where geology is not conducive to storage and pipelines are needed to move captured CO_2 to areas where it can be stored underground, such as in North Dakota. Currently around 6 000 km of CO_2 pipeline is being planned in the United States.

Figure 6.3 The cost and availability of selected biogenic CO_2 point sources and CO_2 needs for achieving a 10% share of low-emission e-fuels in 2030 by transport sector



Notes: 120 000 million litres of bioethanol production (2030), 24 bcm of biomethane production (2030), 150 Mt of chemical pulp production (today).

Under current policies, around 90 Mt of concentrated CO_2 could be available globally from bioethanol plants in 2030. In addition, 30 Mt would be available from plants upgrading biogas to biomethane, increasing the potential availability of low-cost biogenic CO_2 feedstock to 120 Mt by 2030. However, the amount of biomethane increases strongly in the APS and Net Zero Emissions by 2050 Scenario (NZE Scenario). As a result of this growth, 90 Mt of CO_2 could be available by 2030 from biomethane production in the ASP, and this would further expand to 160 Mt CO_2 by 2030 in the NZE Scenario.

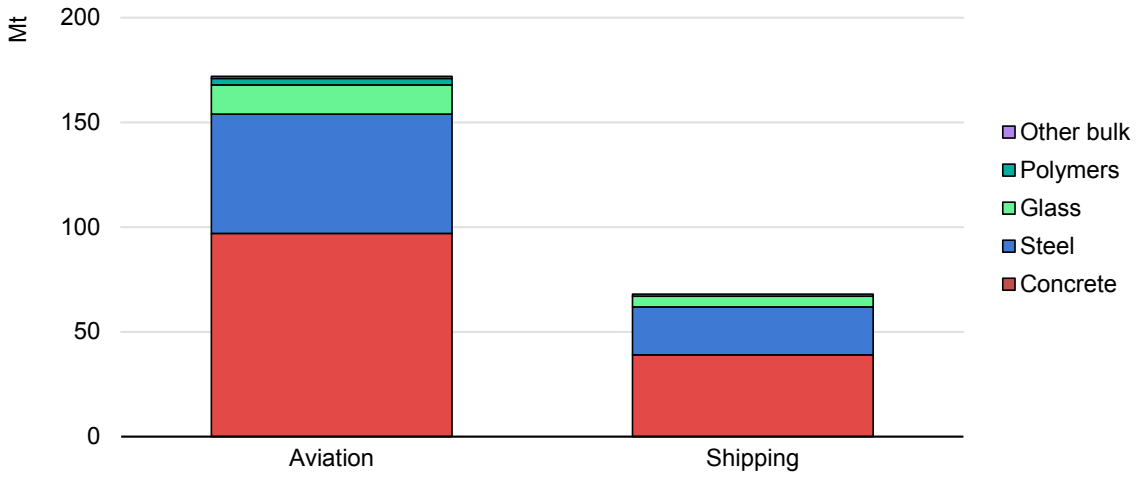
Around 200 Mt CO_2 feedstock would be needed to produce the 10% share of e-kerosene to aviation, and further 150 Mt CO_2 to produce 10% of methanol to marine transport, pushing the combined demand for CO_2 feedstock to 350 Mt. It would not be possible to supply this amount of CO_2 from low-cost biogenic sources alone, but it could be supplemented from kraft pulp mills where large amounts of biogenic CO_2 are being released from the combustion of black liquor and bark and could be captured from flue gases. If marine fuel demand was supplied from low-emission e-ammonia, it would not add to CO_2 demand, releasing more low-cost biogenic CO_2 feedstocks available for low-emission e-kerosene production.

In addition to biomass-based sources, virtually endless supply of CO_2 would be available from the atmosphere at significantly higher cost. However, DAC currently has low technology readiness level, with only 17 DAC plants in operation. The plants are also very small today, with the largest operating plant having a nominal capture capacity of just 4 000 t CO_2/yr. Global DAC capture capacity amounts today to around 8 000 t CO_2/yr.

Bulk materials and critical minerals

Successful deployment of clean energy technologies requires an adequate supply of bulk materials and critical minerals. Since different e-fuel plants are built largely from the same components, they have the same overall bulk material distribution. Concrete represents 60% of the total, followed by steel at 30%. Ammonia, as the most efficient e-fuel production route, requires around 850 t of bulk materials per megawatt of electrolyser capacity. For FT fuels, the bulk materials requirement is 50% higher at 1 300 t/MW_e. Power generation accounts for 90% of overall bulk material requirements. Optimising the economics of e-fuel plants through oversizing of renewables capacity makes a significant contribution to bulk material requirements.

Figure 6.4 Bulk materials needs for achieving a 10% share of low-emission e-fuels in 2030 by transport sector



Notes: Solar PV/wind capacity shares 50%/50%, average renewables oversizing factor of 1.5, electrolyser type: alkaline. Ammonia assumed as the low-emission e-fuel for shipping.

Sources: IEA (2023), Energy Technology Perspectives 2023, IEA (2022), World Energy Outlook 2022.

Total bulk material requirements for achieving a 10% share of low-emission e-fuels in aviation is 170 Mt of which concrete is responsible for 100 Mt and steel 60 Mt. In shipping, bulk material needs are around 60% lower, mostly driven by higher efficiency of ammonia conversion. The total needs are 70 Mt of which concrete is responsible for 40 Mt and steel 20 Mt.

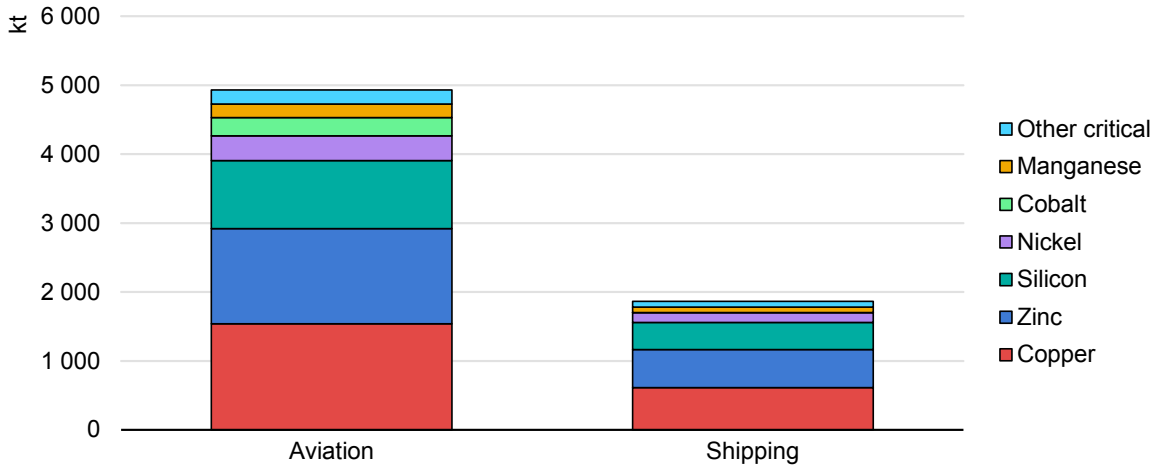
In addition to bulk materials, also critical minerals are needed for e-fuels production. The amount and type of minerals depends on the choice of electrolyser and synthesis technology. The two dominant types of electrolysers, alkaline and proton exchange membrane, have very different mineral requirements; solid oxide electrolysers present fewer mineral concerns, but are less developed.

Alkaline electrolysers have the highest minerals intensity, with current designs requiring more than one tonne per MW of nickel. Reductions in nickel demand for alkaline electrolysers are expected, but nickel is not expected to be eliminated from future designs. Today's state-of-the-art designs use around 800 kg per MW. Nickel is also important for batteries, and if nickel prices rise strongly due to challenges in the battery supply chain, electrolyser costs would be affected. In addition to nickel, 1 MW of alkaline electrolyser could today require around 100 kg of zirconium, half a tonne of aluminium and more than 10 tonnes of steel, along with smaller amounts of cobalt and copper catalysts. PEM electrolysers have significantly lower minerals intensity. PEM catalysts currently use around 0.3 kg

of platinum and 0.7 kg of iridium per MW. SOECs are currently being tested at smaller scales, and have higher efficiencies and low material costs.

Some further differences are introduced by the syntheses that all rely on distinct catalyst metals. Cobalt and iron are used today as catalyst metals for Fischer-Tropsch synthesis. Ammonia synthesis relies on iron catalysts whereas methanol synthesis is catalysed by copper. Additional, albeit small, catalyst demand would come from the reverse water-gas shift (RWGS) reactor that is needed with CO_2-based FT designs.

Figure 6.5 Critical minerals needs for achieving a 10% share of low-emission e-fuels in 2030 by transport sector



Notes: Solar PV/wind capacity shares 50%/50%, average renewables oversizing factor of 1.5, electrolyser type: alkaline. Ammonia assumed as the low-emission e-fuel for shipping.

Sources: IEA (2023), Energy Technology Perspectives 2023, IEA (2022), World Energy Outlook 2022.

Similarly to bulk materials, the need for critical materials is driven by electricity generation, where copper, zinc and silicon dominate. The only critical material that is associated with fuel production and stands out from the overall demand is nickel used in alkaline electrolysers. In total, the critical materials intensity varies from around 20-40 t/MW_e of electrolyser capacity, depending on differences in overall efficiency for fuels production.

Total critical minerals requirement for achieving 10% share of low-emission e-fuels in aviation is 5 000 kilotonnes (kt), of which copper is responsible for 1 500 kt, zinc 1 400 kt and silicon 1 000 kt. In shipping bulk material needs for achieving 10% of e-fuels are around 2 000 kt, of which copper is responsible for 600 kt, zinc 550 kt and silicon 400 kt.

In total, achieving a 10% share of low-emission e-fuels by 2030 in both aviation and shipping would be equivalent to around 20% of the bulk material and critical minerals requirements associated with the expected growth in solar PV and wind capacity between 2022 and 2030 in the STEPS.

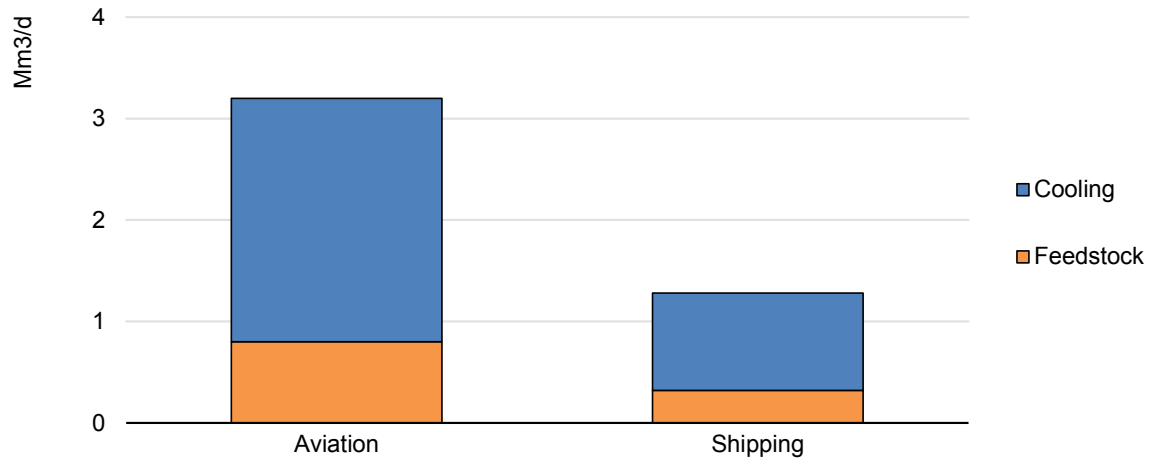
Water requirements

In addition to electricity and CO_2, the production of e-fuels also requires considerable amounts of water. Around 10 litres (L) of water is needed to produce 1 kg of hydrogen through electrolysis. In addition to serving as a feedstock, water might also be needed for cooling the electrolysers. Water requirements depend on the cooling system. Air cooling does not consume any water offering flexibility in site selection. However, a large surface area for heat exchangers and fans that move considerable amounts of air is needed. Also, efficiency is low, especially in hot and arid climates.

Evaporative cooling systems discharge heat through controlled evaporation in a cooling tower. Given the high amount of energy required to evaporate water, a relatively small volume of water is needed. However, water that is used for evaporative cooling cannot be returned to its source because it is lost as vapour in the process. Net water consumption can vary between 30-80 L/kg H_2 depending on the design of the cooling system and climatic conditions.

Once-through cooling uses liquid water that can be returned to its source after use. Heat from electrolysis is transferred to the water, increasing its temperature by about 10°C. Relatively large volumes of water are needed, between 1 500-3 000 L/kg H_2, which is possible only when electrolysers are located close to an abundant water source. Aside from filtering out foreign materials, no treatment of the raw water is needed for cooling purposes. However, regular maintenance is required to prevent corrosion, scaling and fouling in the cooling system.

Figure 6.6 Water needs for achieving a 10% share of low-emission e-fuels in 2030 by transport sector



Notes: Specific water requirements 10 L/kg H_2 for electrolyser feedstock, 30 L/kg H_2 for evaporative cooling.

In terms of water quality, electrolysers require ultrapure water, which needs additional deionisation to reach the conductivity range of 0.1 to 1 µSv/cm. Water used for cooling does not need to be as pure as electrolyser feedwater, but it must be treated for use in evaporative cooling systems to minimise corrosion and prevent fouling in the system.

Ability to supply water for electrolytic hydrogen production varies significantly depending on geographic and climatic conditions. Potential production sites with favourable solar resources are often in arid regions, meaning that limited surface and groundwater resources are likely to be claimed already, largely for agricultural and drinking water uses. Interest towards seawater desalination for hydrogen production in water-stressed areas has thus been increasing.

With increasing capacity and technological learning, the cost of desalination has dropped significantly to around USD 1/m^3. However, local costs vary according to numerous factors such as technology, plant size and feedwater salinity, as well as energy prices and environmental regulations. Even so, the cost of desalinated water has only a small impact on hydrogen production costs. Given that roughly 40 litres of water are needed to produce one kilogramme of hydrogen, the cost impact of desalinated water is only around USD 0.04/kg H_2, or just few percent.

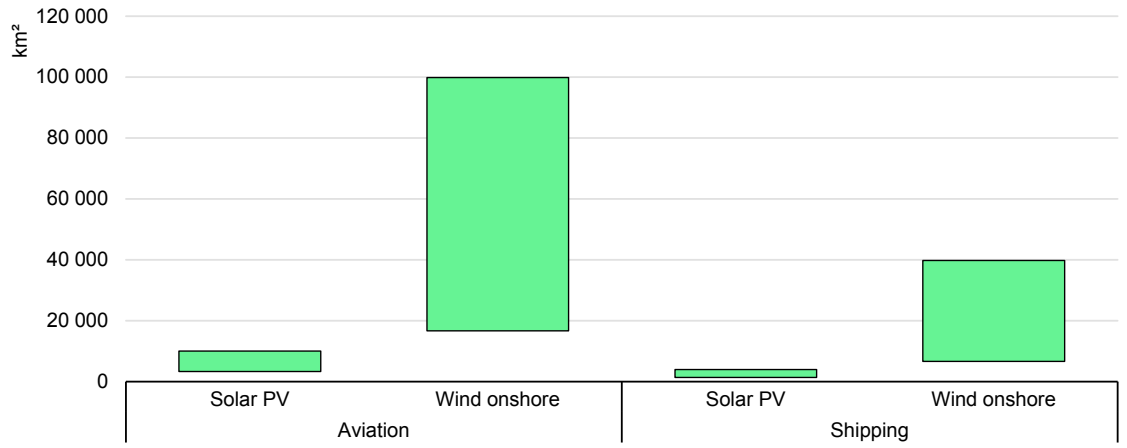
Current state-of-the-art desalination plants enable large-scale production of renewable hydrogen. An electrolyser plant that produces 1 Mt H_2/yr consumes 40-90 Mm^3 of desalinated water, requiring a minimum desalination capacity of 110 000 m^3/d. This is still an average operating condition for desalination plants in countries such as Kuwait, Israel and South Korea, and well below the capacity of the Jebel Ali Desalination Plant in the United Arab Emirates, which is the world's

largest seawater desalination plant with a capacity of 2 Mm^3/d. Overall water requirements for producing a 10% share of e-kerosene for aviation in 2030 is around 3-4 Mm^3/d, while 10% share of e-fuels in shipping would require 1-2 Mm^3/d. When combined, this would be equivalent to around 5% of current global installed desalination capacity that is just over 100 Mm^3/d.

Land requirements

While electrolysers can have a large footprint, most of the land area requirements would be associated with electricity production. Compared to solar PV, wind projects require more land, partly because the vast majority of utility-scale PV takes the form of solar panel arrays, where panels can be placed close to one another. By contrast, wind turbines need a certain amount of space around them to optimise their performance. In this sense. wind turbines do not fully occupy land and it can be co-used for agriculture, etc. The same is true for solar PV that can also coexist with various agricultural practices. However, space required for large projects can be in short supply in densely populated areas. Area requirements also depend on a number of factors, including turbine design and the shape and geography of the production site.

Figure 6.7 Total land needs for achieving a 10% share of low-emission e-fuels in 2030 by transport sector



Source: IEA (2023), Net Zero Roadmap: A Global Pathway to Keep the 1.5 °C Goal in Reach.

Supplying 10% share of e-kerosene to aviation by 2030 would require – assuming 50/50 capacity allocation between solar PV and wind – between 20 000 km^2 and 100 000 km^2 of land. Supplying similar share of marine fuels from e-ammonia would require additional 10 000 km^2 to 40 000 km^2. The total required land area would therefore between 30 000 km^2 and 140 000 km^2. At the lower end, this would correspond the size of Belgium and on the higher end to that of Greece.

Expected lead times

Achieving a 10% share of e-fuels in aviation and shipping by 2030 would require an extremely rapid scale up, but this would not be fully without a precedent. Solar PV and wind were still in their infancy in the 2000s, as were electric vehicles and batteries in the 2010s, but all these technologies have grown into vast manufacturing operations today. At the same time, countries around the world are stepping up efforts to expand clean energy and technology supply chains with the overlapping aims of advancing net zero transitions, strengthening energy security and competing in the new global energy economy. In this context, new technologies may evolve quickly if enough demand materialises.

Although most of the needed components to build low-emission e-fuel projects are mature and available today, fully integrated e-fuel production plants are at the prototype or demonstration stages, and not yet commercially available at scale. They need to be first demonstrated in real operating conditions, probably requiring several "first-of-a-kind" facilities at different sizes or in different regions before they can be deployed successfully at commercial scale. In parallel, fully fledged supply chains would need to be established and expanded progressively. Permitting is also likely to take more time for plants that make use of novel technologies. Additionally, engineering expertise can become a major bottleneck for speedy expansion.

Project experience in bioethanol and biopower plants equipped with CCUS suggests that project lead times on the capture side can range from 1.5-6.5 years, or on average 3.5 years. However, lead times depend on the application and destination of the CO_2. The only two plants involving storage that are in operation today – both bioethanol plants in the United States – took around seven years to complete (including the construction of transport and storage infrastructure). By contrast, projects involving the use of captured CO_2 were completed in less than four years. Given that current facilities are first- or second-of-a-kind, lead times will most likely shorten as deployment increases. In the United States, the lead time for retrofitting the second bioethanol facility with CCUS was one year shorter than for the first.

There are several historical examples of the rapid deployment of new technologies, notably modular and mass-manufactured technologies, which suggest that the rapid rates of deployment of e-fuels could be achievable in a similar way. For technologies and projects with inherently longer lead times, such as mining projects and nuclear power plants, there are also historic examples suggesting industry could sustain fast growth rates. For example, iron ore mining grew in the 2000s at a 10% annual rate, an expansion which was mainly driven by surging demand in China and a tenfold increase in iron ore prices between 2000 and 2010. However, for this to happen producers need a fundamental cost advantage and clear financial incentive to lower lead times and encourage investment and innovation as commercial deployment begins.

Chapter 7. Policy considerations

The development of low-emission e-fuels is at a pivotal juncture. They are recognised for their potential to decarbonise long-haul transportation, particularly for aviation and marine applications, and there are more than 200 e-fuel projects under development globally. However, in the medium-term, low-emission e-fuels are expected to remain much more expensive than fossil fuels and will compete with other low-emission options like biofuels.

To achieve an accelerated deployment of low-emission e-fuels by 2030, robust policies are needed, especially to stimulate demand for new projects. In addition, policies should also facilitate innovation, trade and infrastructure development including in emerging economies. If implemented effectively, they could render low-emission e-fuels an affordable decarbonisation option for aviation and shipping by 2030. They would also contribute to the diversification of decarbonisation options available for transport. Required policy approaches are well known and, in many cases, already underway. While a detailed description of policies and a roadmap for their implementation is beyond the scope of the current report, a set of main policy priority areas is listed below:

Strengthen transport GHG reduction targets and regulations to be consistent with a net zero pathway by mid-century. Global transport emission reduction efforts are currently not aligned with a net zero trajectory by 2050. Enhancing domestic and international transport GHG reduction targets could stimulate a market for low-emission e-fuels, particularly in aviation and maritime sectors where low-emission fuel use remains minimal today.

Provide support to stimulate sizeable and predictable low-emission fuel demand. Demand-side policies are crucial for realising the current low-emission e-fuel project pipeline and for establishing long-term demand. Initial steps should include integrating e-fuels into blending mandates, renewable content requirements, low-emission fuel standards, and other regulations or incentives that encourage low-emission fuels for aviation and shipping. Dedicated targets, like ReFuelEU's aviation sub-targets, are critical for securing a market for initial projects. As production scales up and costs become competitive, policies should evolve to performance-based, competitive models to maintain cost-effectiveness and to encourage innovation.

Stimulate demand creation for all applications of low-emission electrolytic hydrogen to accelerate cost reduction of electrolysers. Achieving lower electrolyser CAPEX is a key component for enabling large-scale deployment of e-fuels by 2030. Electrolyser manufacturers have announced plans for further

expansion, aiming to reach more than 150 GW/yr of manufacturing capacity by 2030, but only 8% of this capacity has reached FID. Realising manufacturers' ambitious plans will depend on solid demand for electrolysers, which today is highly uncertain. All policies that stimulate the deployment of electrolysers, and consequently their cost reduction, will also drive the cost of e-fuels lower. Governments must take the lead and implement policies that encourage private sector activity, combining support measures with regulations (such as quotas or mandates) to prompt the use of electrolysers particularly in existing hydrogen applications.

Continue to develop international standards, protocols and pathways for fuel quality, safety and life-cycle GHG emissions, and strive for mutual recognition. Internationally agreed certification schemes and robust standards are vital, given the potential of e-fuels in international aviation and shipping as well as for trade. Collaboration and alignment, as seen in initiatives from the International Maritime Organization and CORSIA, are crucial, along with continued efforts in regional programmes such as the EU's Renewable Energy Directive.

Address specific challenges and foster investment in emerging market and developing economies. Given that they account for half of the current aviation and marine fuel demand and 80% of the growth to 2030, emerging and developing countries are pivotal for the large-scale deployment of low-emission e-fuels. Yet, many of these countries face important specific challenges, including higher cost of finance, limited access to technology and lack of local skills. De-risking investment and transferring policy and technological insights from advanced economies to emerging and developing countries is essential, considering their significant production and usage potential.

Initiate early planning and accelerate investment in the necessary infrastructure. An accelerated scale up of low-emission e-fuels in shipping requires significant investments in transport, storage and distribution infrastructure, as well as end-use equipment. Given that the completion of such infrastructure usually takes more than three years, the planning and construction would need to begin in the next few years for them to be operational by 2030.

Assess and exploit potential synergies with biofuels deployment. By-product CO_2 from fermentation processes and from biomethane plants are among the cheapest sources of CO_2 feedstock for e-fuels production. However, biofuel plants are not always situated in locations with the best wind and solar PV resources. Development of low-emission e-fuels should look for synergies with biofuels production and CO_2 infrastructure. This further highlights the potential synergies between e-fuels, biofuels and CCUS, which will be the subject of a joint cross-initiative Future Fuels Accelerator Programme under the Clean Energy Ministerial in 2024.

Foster innovation and support RD&D. Low-emission e-fuels support policies should include R&D fostering advanced process integration and developing high-efficiency components. Low efficiency can be addressed to some extent by scaling up high-efficiency, high-temperature electrolyser technologies. Components that still have a low technical readiness level today like reverse water-gas shift reactors need to be demonstrated at scale. New synthesis routes from CO_2 to liquid hydrocarbons should also be explored in addition to the well-known Fischer-Tropsch route.

Annex

Abbreviations and acronyms

ASTM	American Society for Testing and Materials
AEM	anion exchange membrane
ASU	air separation unit
CAGR	compound annual growth rate
CAPEX	capital expenditure
CO	carbon monoxide
CO_2	carbon dioxide
CCUS	carbon capture, utilisation and storage
DAC	direct air capture
EV	electric vehicle
FID	final investment decision
FT	Fischer-Tropsch
GHG	greenhouse gas
H_2	hydrogen
HDV	heavy-duty vehicle
HFO	heavy fuel oil
ICAO	International Civil Aviation Organization
IMO	International Maritime Organization
LCOE	levelised cost of energy
LDV	light-duty vehicle
LHV	lower heating value
LNG	liquified natural gas
MGO	marine gasoil
MSW	municipal solid waste
MTG	methanol-to-gasoline
MTO	methanol-to-olefins
Ni	nickel
N_2	nitrogen
NOx	nitrogen oxides
PEM	proton exchange membrane
PM	particulate matter
PPA	power purchase agreement
PV	photovoltaic
Ru	ruthenium
RWGS	reverse water-gas shift
SAF	sustainable aviation fuels
SOEC	solid oxide electrolyser cell
TCO	total cost of ownership

TEU	twenty-foot equivalent unit
USD	US dollar
WACC	weighted average cost of capital
WGS	water-gas shift

Units of measure

bbl	barrel
b/d	barrels per day
EJ	exajoule
g CO_2	gramme of carbon dioxide
g CO_2/kWh	gramme of carbon dioxide per kilowatt hour
GJ	gigajoule
GW	gigawatt
GW_e	gigawatt electrical
GWh	gigawatt hour
kb/d	thousand barrels per day
km^2	square kilometre
kt	kilotonnes
kW	kilowatt
kW_e	kilowatt electrical
mb/d	million barrels per day
MJ	megajoule
Mm^3	million cubic metres
µSv	microsievert
Mt	million tonnes
MW	megawatt
MW_e	megawatt electrical
MWh	megawatt hour
pkm	passenger kilometres
t CO_2	tonne of carbon dioxide
t CO_2/yr	tonnes of carbon dioxide per year
tkm	tonne kilometres
TWh	terawatt hour

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