International Transport Forum

Managing Competing Sectoral Demands for Energy Resources

Transitioning to Sustainable Transport

Case-Specific Policy Analysis

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The International Transport Forum

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International Transport Forum
2 rue André Pascal
F-75775 Paris Cedex 16
contact@itf-oecd.org
www.itf-oecd.org

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Abbreviations and acronyms

BEV	Battery electric vehicle
CAGR	Compound annual growth rate
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CCU	Carbon capture and utilisation
CO_2	Carbon dioxide
DAC	Direct air capture
DACS	Direct air capture and storage
DACCS	Direct air capture with carbon sequestration
DACCU	Direct air capture with carbon utilisation
EJ	Exajoule
EUR	Euro
EV	Electric vehicle
FCEV	Fuel cell electric vehicle
FID	Final investment decision
GHG	Greenhouse gas
GW	Gigawatt
HGV	Heavy goods vehicle
HVO	Hydrotreated vegetable oil
ICE	Internal combustion engine
ICEV	Internal combustion engine vehicle
IEA	International Energy Agency
ITF	International Transport Forum
LCOE	Levelised cost of electricity
LCOH	Levelised cost of hydrogen
LCV	Light commercial vehicle
MAC	Marginal abatement costs
MJ	Megajoule
MSW	Municipal solid waste
NZE	Net zero emissions

OPEX	Operating expenditure
PtL	Power-to-liquid
PV	Photovoltaics
RE	Renewable electricity
RFNBO	Renewable fuels of non-biological origin
SAF	Sustainable aviation fuel
SMR	Small modular reactors
SUV	Sport utility vehicle
TCO	Total cost of ownership
USD	United States Dollar

Executive summary

Key messages

- Allocate scarce energy resources using a cross-sectoral merit order
- Pre-emptively minimise resource scarcity by promoting efficiency and prioritising uses
- Prioritise direct electrification, avoid hydrogen and e-fuel technologies for road and rail transport
- Prioritise sustainable bioenergy complemented with e-fuels for hard-to-abate transport modes such as long-distance aviation and maritime shipping

What we found

Decarbonising the economy requires key energy and non-energy resources such as low-carbon electricity, low-carbon hydrogen, sustainable bioenergy and sustainably produced synthetic fuels including carbon capture technologies sequestering CO_2. Many of these resources need to be scaled up at unprecedented speeds to meet climate goals, which is challenging. As production gradually increases, energy resources will be relatively scarce; therefore, they should be used efficiently and prioritised in sectors where they will have the greatest emissions savings in the long term.

Different sectors of the economy will compete for the same limited energy resources as they seek to decarbonise. The same energy resources can have a different impact on decarbonisation and associated costs when applied in different sectors or transport modes, and some might have limited alternatives for decarbonisation. Existing sector or mode-specific regulatory structures mean energy resources may not be optimally allocated for effective emissions savings. For example, blending mandates for biofuels in road transport, which has more efficient and cost-competitive solutions to decarbonise, reduce the availability of feedstock for long-distance aviation or high-temperature heat applications in industry, which has few decarbonisation alternatives. Such a misallocation risks hampering decarbonisation and increasing the costs of meeting climate targets. Governments should develop a cross-sectoral regulatory framework for energy resources following a "merit order" principle to manage such scarcity and guide markets to better allocate scarce resources.

Direct electrification of end-use applications, such as road transport or residential heating, helps to decarbonise the economy across sectors in the cheapest and most energy-efficient way, thus contributing to COP28's goal of doubling energy efficiency. The availability of cheap, low-carbon electricity is a key pillar in the transition to sustainable economies and fewer constraints than other energy resources. The deployment rate of renewable electricity is nearly on track to meet the demand compatible with climate targets in net-zero scenarios if record-breaking growth rates from recent years can be maintained over the coming years. Conversely, low-carbon hydrogen and e-fuel production is lagging behind the levels needed to reach any net-zero scenario.

Using hydrogen in the road transport sector is suboptimal since electrification is available and almost always more energy-efficient and cost-competitive. Other sectors, such as chemicals and primary steelmaking, are a higher priority for low-carbon hydrogen, as they cannot fully decarbonise with direct electrification. Therefore, they are also likely to have a higher willingness to pay for low-carbon hydrogen in a regulated environment. Promoting low-carbon hydrogen use in industrial sectors with resilient demand for hydrogen and limited cost-effective alternatives is likely a cheaper and more robust way to scale up low-carbon hydrogen production and minimise the risk of stranded assets.

Sustainable bioenergy feedstocks from non-food crops play an important role in decarbonising the economy but are inherently limited in supply. They can meaningfully contribute to decarbonising hard-to-abate sectors, such as long-distance aviation, maritime shipping or some industry applications, such as providing high-temperature heat. However, they are not available in sufficient quantity to decarbonise the entire transport sector. They should, ideally, only be prioritised for transport modes with few cost-effective alternative technologies such as aviation. However, this also needs to be balanced with equity concerns and regional differences since biofuels can help emerging economies to decarbonise and aviation demand is dominated by the relatively wealthy.

Producing e-fuels using renewable electricity can contribute to decarbonising shipping and aviation demand in the long term. However, their production is still low in technology readiness and energy intensive, principally due to the need to make electrolytic hydrogen. Carbon-based e-fuels also require a sustainable carbon source for their production to limit CO_2 additions to the atmosphere. Capturing CO_2 at scale remains costly and needs further development. Betting on e-fuels to decarbonise road transport risks delaying the necessary transition to direct electrification, which is more energy-efficient and cost-competitive and will tie up resources needed for hard-to-abate modes. While research, development and scale-up on e-fuels are necessary, it is clear they should only be targeted towards sectors that have no cheaper or more efficient option to decarbonise in the long term.

Aligning government energy policies with such a cross-sectoral merit order principle is essential to optimally use scarce energy resources globally in order to maximise emissions savings and reach climate targets in a more cost-efficient way.

What we recommend

Prioritise scarce resources with a merit order to maximise emissions savings

Current decarbonisation policies are often sector-specific and lack a holistic approach. This can cause sectors to compete for the same limited energy resources, such as biofuels and hydrogen. Sub-optimal resource allocation can deteriorate their emission-saving potential. Governments should use a cross-sectoral prioritisation, or “merit order”, to develop regulations and guide markets to optimally allocate scarce energy resources, based on sectors’ critical needs and where alternative cost-competitive decarbonisation options are limited. The merit order should be based on market fundamentals, using resources where they have the biggest environmental impact at the lowest additional cost and where alternatives are limited, while guided by social equity and fairness considerations.

Prioritise the use of biofuels and e-fuels for sectors with limited alternatives to decarbonisation

Applying a merit order can help to highlight that the use of biofuels in the road transport sector is lower in priority than using them in decarbonising the hard-to-abate sectors. Sustainable biofuels and e-fuels are particularly useful to decarbonise sectors where direct electrification and other technologies are not possible, such as long-distance aviation and maritime shipping, but they are likely limited in their availability at scale. The use of e-fuels in road transport is particularly low priority given their energy inefficiency, the limited availability of sustainable carbon feedstock and the inherent higher costs compared with direct electrification. Current commercially mature biofuel pathways mostly rely on food crops. Sustainable biofuel supply needs to be ramped up significantly, through adaptation of existing commercially mature pathways to using sustainable feedstock and expanding pathways such as with alcohol-to-jet or biomass gasification/Fischer–Tropsch fuels, which are not commercially available so far. Shifting blending mandates for biofuels from road transport to long-distance aviation is important to streamline scarce supplies to sectors with few alternatives for decarbonisation. Specific mandates for these alternative fuels are most effective in hard-to-decarbonise modes with resilient demand, where they are unlikely to be outcompeted by more cost-competitive solutions, such as direct electrification for road and rail.

Prioritise the electrification of end uses to promote energy efficiency where possible

Direct electrification of end-use applications increases energy efficiency, which is particularly important if energy resources are scarce. Electrification should be prioritised in all sectors across the economy where it is the most cost competitive. Low-carbon electricity supplies are set to be less constrained than other energy resources, such as hydrogen and biofuels. Since most economies have access to some cost-competitive renewable electricity supply, electrification can also help increase energy security.

Avoid mandating the use of hydrogen in road transport and favour sectors with more resilient demand

Hydrogen risks to see limited adoption in road transport modes since it is likely to be outcompeted by direct electrification, which is more efficient and cheaper. Governments should consider public spending on hydrogen-related assets for road transport with great care to avoid stranded assets. If governments mandate the use of hydrogen in road transport, they risk locking in an uncompetitive technology in the long term, which will require continuous public financial support. Scarce, low-carbon hydrogen is likely to be more effectively used in industrial sectors with limited alternatives to abate greenhouse gas (GHG) emissions or replace existing fossil hydrogen in applications such as fertiliser production. Mandates to stimulate low-carbon supply and demand growth are better suited for these sectors.

Avoid scarcity of key energy resources by unlocking supply and limiting demand

Economy-wide decarbonisation requires the vast availability of low-carbon electricity and fuels. Most emission savings are contingent on the carbon intensity of the electricity mix, making the rapid deployment of low-carbon electricity generation, such as solar photovoltaics (PV) and wind, of utmost importance. Governments must retain and expand their efforts in deploying low-carbon technologies to meet climate targets. Using low-carbon resources more efficiently, including moving to sustainable transport modes, is an important complementary measure to reduce scarcity. Efficient resource use also enables a greater number of people to benefit from them and promotes a just transition.

Introduction

Over 100 countries, responsible for 80% of global greenhouse gas (GHG) emissions, have committed to net-zero targets through laws or pledges. Decarbonising the entire economy requires several key energy resources, including low-carbon electricity, hydrogen produced from low-carbon sources, bioenergy and carbon capture technologies sequestering CO_2 to produce synthetic fuels. These resources need to be deployed at unprecedented speed to meet climate targets. Such a quick deployment is challenging, and several bottlenecks have already been encountered. Consequently, it will take time to gradually scale up supply of these essential energy resources. During this period of gradual scale-up, it is particularly important that these energy resources are used frugally to maximise collective societal benefits and minimise risks. This will require resource prioritisation towards end uses which will likely experience resilient demand and in sectors where there is long-term potential to reduce greenhouse gas emissions (GHG) globally.

These key energy resources are needed in multiple sectors of the economy to reach their respective climate targets. The transport sector's need for low-carbon energy must compete with other sectors such as industry and buildings, all racing to decarbonise using the same limited supply of low-carbon energy resources. Different transport modes may also compete for the same energy resources, such as biofuels. Bottlenecks in the supply of low-carbon energy to decarbonise energy for existing uses will be exacerbated in the future with increasing demand for key energy resources.

Mismatches in supply and demand could result in price hikes or delays, slowing down the decarbonisation process for transport and beyond. Additionally, countries and regions with varying access to resources and purchasing power face different challenges, further complicating the global transition.

In principle, competition for energy resources between sectors can be beneficial. Allowing market forces to decide which technologies or energy resources are used in each sector can help to minimise costs. However, not all new low-carbon resources can be used interchangeably, and some will have greater benefits if used in a specific sector or application.

For example, many sectors see biofuels as playing an important role in decarbonisation due to their compatibility with existing technologies and relative affordability compared to some alternatives. Biomethane could be used with relative ease in a range of sectors where fossil natural gas is already used, including the industry, energy or transport sectors. Similarly, liquid biofuels could be used in the transport sector for various transport modes, including road transport, rail, aviation or shipping, with minor adaptations to existing engine technologies. However, the long-term availability of sustainable bioenergy feedstocks is limited, particularly those based on waste streams or agricultural residues. The short-term availability of many of these energy resources is even more constrained as their production gradually scales up using new or modified production facilities required to process different, more sustainable types of feedstocks of biological origin. The existing use of biofuels mainly uses primary, biogenic feedstock from food crops. This constrained availability means there must be a prioritisation of their use, particularly towards sectors with fewer cost-effective alternatives. Long-distance aviation or hard-to-abate applications in industry arguably have a greater need for biofuels since, unlike road transport, electrification is not an option.

Current market conditions and regulatory structures may not be set up to allocate resources to the sector requiring them most for decarbonisation. For example, tax exemptions and mandates for biofuels in the road sector may result in a higher willingness to pay for these resources that could otherwise be used in harder-to-decarbonise sectors such as aviation. The tax exemption on fuels used for international aviation and shipping and the general taxation of road fuel further increases the cost gap of biofuels for use in different transport modes. Therefore, governments have an important role to play in guiding the market in better allocating limited energy resources.

Government policy is essential in stimulating the early market deployment of the new technologies needed to decarbonise by overcoming the market risks that prevent private-sector action. However, government policies aiming to promote one sector's decarbonisation in isolation could impact other sectors if there is competition for the same resources. Blending mandates for fuels in one sector may deprive other sectors with fewer or no alternatives for essential resources.

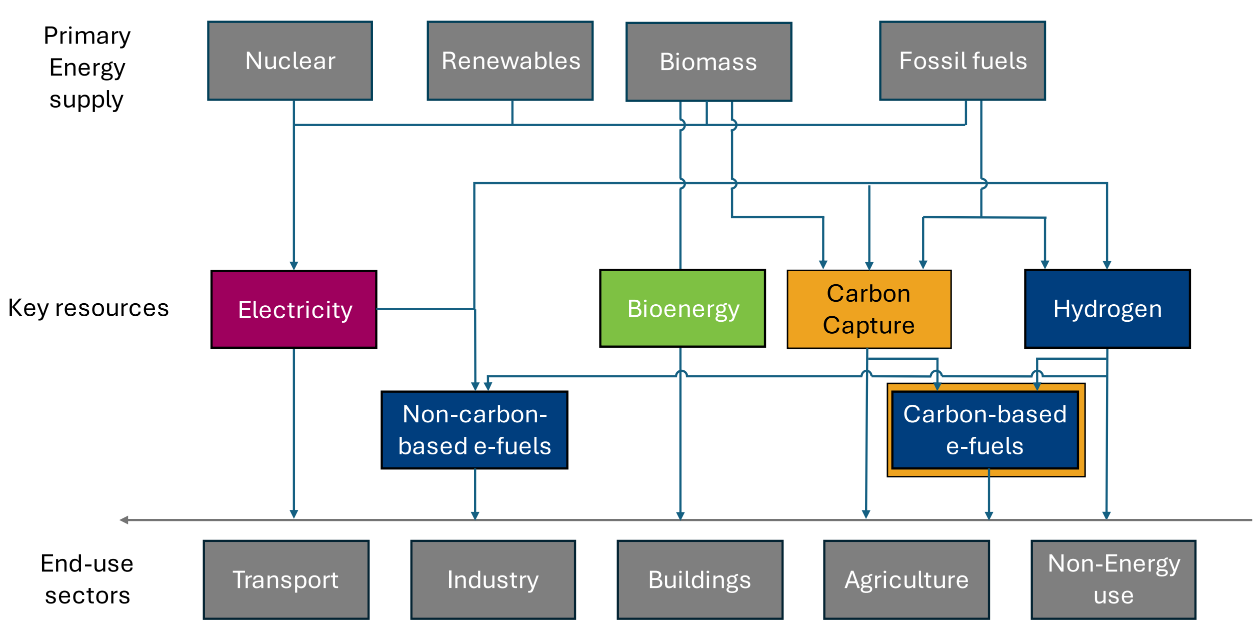
This report explores the possibility that applying and clearly communicating a merit order for prioritising the use of energy resources can help guide government interventions. The next chapter will introduce key energy resources and highlight their importance for economy-wide decarbonisation. Comparing their supply and future demand indicates that there is a potential scarcity if governments want to meet climate targets. The final chapter introduces different merit order principles on how resources could be prioritised. The report concludes with a proposed merit order of resource allocation for the transport sector with selected examples from other sectors, taking into account indicators such as marginal abatement costs, the effectiveness of GHG savings per energy unit and non-techno-economic considerations, such as regional specificities and equity aspects.

Key energy resources for a low-carbon economy

Decarbonising all sectors of the economy requires several key energy resources, which need to be scaled up at unprecedented speed. The concurrent need for these resources by multiple sectors along with inefficient use can lead to scarcity if supply lags behind demand. This could lead to negative consequences for decarbonisation efforts if the demand from all sectors cannot be met, technically or economically. The following sections will identify the four resources most relevant to economy-wide decarbonisation and highlight the challenges related to scaling them up to match the demands required to meet ambitious climate targets.

The four key energy resources examined are renewable electricity, low-carbon hydrogen, bioenergy (including biomass, biogases and bioliquids) and carbon capture technologies used to produce synthetic fuels or offset unavoidable emissions. The key resources identified in this report are not exclusively primary energy carriers, but elementary resources that are already used in today's economy and require decarbonisation, or resources that will be needed for a low-carbon economy. Figure 1 shows how these energy resources can be produced from primary energy sources and how they are used in various end-use sectors. While most of these key resources rely on low-carbon electricity to be produced (with the exemption of bioenergy), there can be other barriers to availability. For example, unlimited availability of low-carbon electricity does not imply that hydrogen or synthetic fuels will be equally abundant since there are additional inputs necessary, such as the availability of carbon feedstock or required technologies at scale, such as production facilities. Therefore, this report refers to a key energy resource as the product of various inputs and aims to identify the most critical input or feedstock that might hinder supply of this resource.

Figure 1. Key resources for a low-carbon economy



Other resources critical to decarbonisation include battery materials, energy storage capacities and grid infrastructure. By focusing on the aforementioned four principal energy resources, this report hopes to demonstrate the need for a merit order for their use, which could be adapted to include a greater number of resources.

Renewable electricity

Renewable electricity (RE) production capacity is one of the pillars of a decarbonised economy. It is needed as an input to several derived energy resources and to provide essential services to society. Fully decarbonising the economy will require significant amounts of low-carbon electricity in short timescales. Low-carbon electricity can be produced with various pathways, ranging from hydropower, nuclear, and fossil energy with carbon capture and storage (CCS) as well as wind and solar photovoltaics (PV). However, these production pathways vary considerably in cost and ability to be deployed quickly at scale. The levelised cost of electricity (LCOE) for new nuclear power generation was over five times more expensive than solar PV or onshore wind power generation in 2023, with natural gas using CCS three times more expensive[1] (BloombergNEF, 2023). Small Modular Reactors (SMR) are under development with commercialisation still in the relatively early stages (OECD/NEA, 2023), making SMRs unlikely to provide sufficient low-carbon electricity in the short timescales needed. The LCOE of hydropower varies significantly with the size of the plant and by region (through expensive access to capital) but stands at around USD 60 per megawatt hour (MWh) on a globally weighted average. Since the economically viable hydropower potential is nearly fully exploited in Europe (European Commission, 2021), future additions will likely be restricted to other regions in the world, such as Africa, where around 90% of the potential has not yet been developed (IRENA, 2015).

Solar PV and wind power generation have experienced a historic decline in costs in recent years, of 82% over ten years for utility-scale PV systems (NREL, 2021). They are now the cheapest source of low-carbon electricity. Low technical complexity and modularity may well lead to further cost reductions (Wilson et al., 2020), making solar PVs and wind power the most likely technologies to play a crucial role in the energy systems of a decarbonised economy.

Renewable electricity already accounted for 30% of global electricity consumed in 2023 (IEA, 2023g). According to the IEA's Net Zero Emission (IEA NZE) scenario, which reaches goals of limiting global warming to 1.5°C above historical averages, global electricity demand will increase from around 29 petawatt hours (PWh) in 2022 to 77 PWh in 2050 (IEA, 2023g). Key drivers of this growth include increases in population and economic development, but also new forms of demand, arising from technologies like electric vehicles (EVs), heat pumps, electrolytic hydrogen and e-fuels. In this scenario, approximately 90% of electricity production must be renewable by 2050, with wind and solar power accounting for 70% of electricity production. To achieve such ambitious 2050 targets, solar PV production needs to increase fivefold and wind power threefold by 2030 from today's levels (see Table 1), requiring a compound annual growth rate (CAGR) of 26% and 16%, respectively. By 2050, a 20-fold increase in solar PV and a 10-fold increase in wind power will be needed, compared to today's level, with a CAGR of 12% and 9%, respectively, between today and 2050. The high growth rates in deploying new renewable electricity generation capacity in the years to 2030 are critical to achieving the targets.

However, the huge demand required from the global economy is counterbalanced by the record-breaking deployment of renewable electricity in recent years. Over the last two decades, the installed capacity for solar PV and wind has increased by a factor of 10 and 3.5, respectively, with a CAGR of 28% and 14% (IEA, 2024d; see Table 1). The growth rates required to attain 2030 net-zero targets are similar to exponential growth rates from the last decade globally (RMI, 2024). While there may be regional differences in the deployment rate of renewable energy sources, several energy modelling scenarios suggest that linear capacity additions over the next years could be sufficient to meet EU 2040 targets for climate neutrality pathways (ECEMF, 2023).

Maintaining record-breaking growth rates from the last years over the next decade could enable meeting global targets, however, challenges such as public acceptance or financing in less developed countries could hinder the possibility of meeting them. Due to these challenges, it is crucial not only to maintain or further develop policy support, but also to ensure that systemic inefficiencies in the use of renewable electricity are avoided.

Table 1. Global renewable electricity production with past and required growth rates.

RE source	Annual production (2023)	Annual production target in 2030	Historic CAGR (from 2010–2023)	Required CAGR for 2030 target
Solar PV	1 600 TWh	8 000 TWh	28%	26%
Wind power	2 100 TWh	7 000 TWh	14%	16%

Note: RE = Renewable electricity. CAGR = compound annual growth rates. Production required to meet IEA NZE targets.

Source: Based on data from the Renewable Energy Capacity Tracker (IEA, 2024d) and RMI The Cleantech Revolution (RMI, 2024).

Other challenges arise when countries achieve a very high share of variable renewable electricity sources like solar PV or wind. Since they are inherently fluctuating, their integration into the electricity grid requires flexible solutions (IEA, 2024c). Key examples of these solutions include demand response and storage capacities. In road transport, they can be enabled by EVs and vehicle-to-grid technologies, which can help limit the need for grid reinforcement and accelerate the integration of large shares of renewable energy supplies (IEA, 2024d).

Hydrogen

Hydrogen is already widely used in various industries, such as for fertilisers and chemicals, with consumption at 97 million tonnes (Mt) in 2023 (IEA, 2024b). Hydrogen is difficult to replace in many processes, including in the production of fertilisers and other chemical products. To align these same products with the requirements of a net-zero transition, hydrogen production must be decarbonised. This will be particularly challenging on the path to a sustainable economy within reasonable timescales, since 99.3% of current hydrogen production is still fossil-based (IEA, 2024b).

Low-carbon hydrogen can also play a role in decarbonising other sectors that would struggle to be directly electrified. The production of primary steel is a key example, as it could use low-carbon hydrogen to replace coal as a reducing agent (IEA, 2020a). Other examples include the use of low-carbon hydrogen as an energy carrier and as a low-carbon feedstock in fuel making (e.g. in hydrogenation units and for synthetic fuels).

Low-carbon hydrogen can be produced via the electrolysis of water using low-carbon electricity (“green hydrogen”) or from fossil fuels such as natural gas through conventional steam reforming with the consequent carbon capture and storage (CCS) of the emitted CO_2 (“blue hydrogen”). Both technological pathways have distinct challenges. The costs and net-GHG balance of blue hydrogen strongly depends on the capture rates of CO_2 and fugitive methane, carbon pricing, natural gas prices and legislation on methane leakage. Recent studies have shown that the window for the cost-competitiveness of blue hydrogen may have already closed in some combinations (Ueckerdt et al., 2024) and will narrow even further with the decreasing cost of electrolyser systems.

The current supply of green hydrogen is almost non-existent (1 Mt) and would need to increase to 65 Mt according to the IEA’s NZE. Although announced projects have surged recently, actual project implementation with final investment decisions (FID) remains one of the biggest challenges. Only 4% of recently announced projects (by capacity) have obtained FID, with projects in early stages of development having lower chances of success (IEA, 2024b). In previous years, success rates have proven challenging. For example, only 3% of project announcements for 2022 were completed on time, with 76% delayed and 21% never realised (Odenweller and Ueckerdt, 2024). This shows that achieving sufficient supply of low-carbon hydrogen remains challenging, and a gap between announcements and realisation persists.

Recently, there has been increasing interest in the potential of naturally occurring geologic hydrogen, commonly referred to as ‘white’ hydrogen. Once considered very scarce, the development of new sensing equipment is generating increased interest in this resource (RystadEnergy, 2024). White hydrogen could theoretically offer a relatively low cost of extraction (around USD 1/kg) with low greenhouse gas emissions intensity. However, its transportation and distribution share the same challenges as conventional hydrogen, and therefore make its subsequent use close to the discovery site likely. While significant uncertainty still exists in the scale of the available resource, one recent analysis estimated an available supply of 2 EJ by 2050 (Wood MacKenzie, 2024). This equates to roughly one-eighth of the expected hydrogen demand in the IEA NZE scenario and suggests white hydrogen is currently expected to remain relatively niche and far from the basis for a long-term national industrial strategy.

The average projected demand for hydrogen varies throughout the literature, as does the scope of application of hydrogen as a decarbonisation solution (Jackson, 2024; Moore, 2024). Conservative projections focus on replacement of existing uses with low-carbon hydrogen and demand concentrated in industrial clusters (Liebreich, 2020). Some can even see a contraction of hydrogen use in the economy (Barnard, 2023). If this is the case while decarbonisation progresses, the growing share of energy from direct electrification might reduce the demand for hydrogen. This shift is driven by fewer products relying on hydrogen as a feedstock (e.g. road fuels) and through end-use efficiency improvements of hydrogen-based products (e.g. precision agriculture, fertiliser use without productivity losses). More optimistic energy-related projections on hydrogen demand developments foresee an increase in hydrogen use with decarbonisation, as they tend not to factor in the same dynamism in demand reductions from existing non-energy uses (in particular fertilisers). Projections pointing towards a growth in hydrogen use in the economy also foresee a growth of more hydrogen-intensive end-use applications (as in the case of ammonia becoming a replacement for shipping fuels of fossil origin) and the possibility to have a relevant role for long-duration energy storage – where hydrogen competes with other technologies, from heat pumps to compressed and liquid air (Schmidt et al., 2019; The Royal Society, 2023).

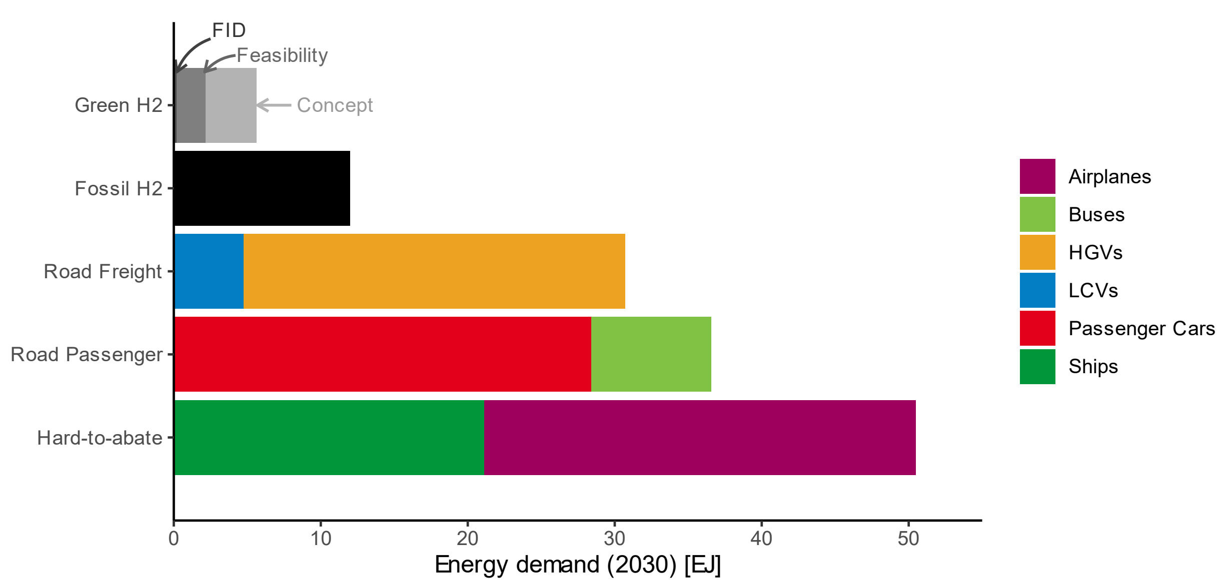
Consequently, projections around the key components needed for low-carbon hydrogen production also vary. Electrolyser capacity, necessary for green hydrogen production from low-carbon electricity, ranges from below 100 GW to more than 1000 GW, with a median of around 350 GW in 2030 (Odenweller and Ueckerdt, 2024).

Expectations for future hydrogen demand have been recently revised downwards by several organisations. This took place as more economic alternatives, such as direct electrification (e.g. heat pumps for residential heating or electric vehicles for road transport, or pumped hydro for long-duration energy storage), have gathered a growing consensus regarding their cost competitiveness. For example, Bloomberg New Energy Finance (BNEF) reduced projections for low-carbon hydrogen demand to 390 Mt in its 2024 net-zero scenario, down from 502 Mt in its previous assessment (Martin, 2024). In IEA NZE scenarios, the required electrolyser manufacturing capacity decreased from approximately 850 GW in 2021 to around 550 GW in 2023 as the hydrogen share in the residential and transport sector was revised downwards (Odenweller and Ueckerdt, 2024).

Figure 2 shows the projected green H_2 supply in 2030 by project status (projects that are operational or have reached final investment decision, projects at feasibility planning stage, and early-stage project still at concept level). Figure 2 also shows the remaining expected demand for fossil hydrogen in 2030 from existing uses from the IEA NZE scenario (which already includes a net reduction from today's levels).

Finally, Figure 2 shows the hypothetical hydrogen energy demand if all of the transport sector used hydrogen fuels in 2030. It should be noted that this is not a forecast of actual hydrogen use but a hypothetical demand for hydrogen in transport, assuming that all modes use hydrogen or hydrogen-based fuels (aviation using synthetic kerosene and shipping using ammonia). The methodology is further detailed in Annex A.

Figure 2. Supply of fossil and green H_2 versus hypothetical demand in 2030



Note: HA = High Ambition; FID = Final Investment Decision; LCV = Light Commercial Vehicles; HGVs = Heavy Goods Vehicles; Green H_2 refers to electrolytic hydrogen. Hydrogen demand is expressed in final energy and transport technology efficiencies are detailed in Annex A. The hydrogen projects that have obtained FID are less than 10% than those for feasibility and this too small to be displayed.

Sources: Fossil H_2 demand from IEA NZE 2030 (IEA, 2023c). Green hydrogen availability by project status from IEA (2024b) and Odenweller and Ueckerdt (2024). Transport energy demand adapted the high ambition scenario ITF's Transport Outlook 2025 (ITF, forthcoming) hypothetically assuming all road vehicles used hydrogen fuel cells, all airplanes used synthetic SAF and all ships used ammonia.

Figure 2 clearly shows that projected green hydrogen supply lags behind the potential hydrogen demand in transport by several orders of magnitude. Projects that are currently operational or have already obtained FID for 2030 are negligible. The optimistic scenario for low-carbon hydrogen supply in 2030, assuming that all projects will be realised, would replace less than 50% of the expected fossil H_2 demand in 2030. If this supply is, instead, allocated to the transport sector, it could only provide a small share of hard-to-abate transport needs, such as aviation or shipping. This highlights the need for prioritisation of the use of scarce low-carbon hydrogen resources.

The costs for green hydrogen currently remain a major hurdle. The levelised cost of green hydrogen (LCOH) remains high for many projects and the cost of electrolyser systems cannot be expected to follow the same decline as that, for example, of solar PV (Ramboll, 2023). Therefore, the cost gap is expected to persist for at least a decade (Ueckerdt et al., 2024). The full end use costs of hydrogen are also impacted by costs of downstream production, including storage, distribution and refuelling. Such costs vary by sector and application. While these costs may only add 50% to the production costs in cases where hydrogen is used in stationary applications (e.g. ammonia production, or other industrial uses), they can add up to 200% to the production costs in transport applications such as heavy-duty road freight (Shafiee and Schrag, 2024).

The European Hydrogen Bank recently conducted its first pilot auction for green hydrogen in April 2024, with winning bids ranging between EUR 0.37 and EUR 0.48/kg of H_2 (Hydrogen Europe, 2024). This was significantly lower than the ceiling price of the auction of EUR 4.5/kg of H_2, which is approximately the cost difference between hydrogen from fossil fuels and its green counterpart for the most cost-competitive projects. As a result, most of the cost difference between the bidding price and actual production costs are mostly covered by the end consumer[2], which implies their high willingness to pay in the European context (FSR, 2024). A second bidding round is expected at the end of 2024. Both bids will support a total volume of 0.7 Mt of H_2 by 2030, which is only a fraction of the 10 Mt H_2 target for 2030 based on the EU's 2020 Hydrogen Strategy.

In conclusion, the current supply of green hydrogen is low and bringing hydrogen projects to fruition remains challenging with a limited number of projects reaching FID, lagging behind the demand needed for net-zero pathways. Achieving all planned projects by 2030 would require USD 1-1.5 trillion in investment. However, only USD 300 billion has been announced globally so far. Governments are undertaking remarkable policy efforts with direct or indirect subsidies, such as through the Hydrogen Bank in the European Union or through the Inflation Reduction Act in the United States. Despite these efforts, low-carbon hydrogen will remain scarce and expensive for at least the next decade, which will require the prioritisation of this resource to sectors and applications where it can be best used.

Bioenergy

Modern and sustainable bioenergy can play an important role in achieving net-zero goals. Biomass derivatives in liquid or gaseous forms, such as biofuels or biogas are versatile and can be employed in multiple sectors using existing infrastructure (e.g. gas turbines and transmission/distribution in the power sector or internal combustion engines in road transport). The use of existing infrastructure helps to make biofuel use relatively cheap.

Today's global use of bioenergy is 67 exajoules (EJ), with the majority currently used as traditional solid biomass for heating and cooking in emerging economies along with modern solid bioenergy in the power and industrial sectors. Only around 5 EJ are used as gaseous or liquid biofuels (Table 2). Liquid biofuels are currently mostly blended with fossil fuels for use in the road transport sector. Conversely, the vast majority of biogases are used to provide electricity and heat in buildings and industry with an insignificant share being used in transport. Only 30% of biogases are currently converted to biomethane, of which one-fifth is then used in the transport sector (IEA, 2023d).

Table 2. Global bioenergy supply, 2022

	Total supply (2022) [EJ]	Share of advanced feedstock
Total bioenergy	67	45%
Liquid bioenergy	4	12%
Gaseous bioenergy	1.6	–

Source: IEA (2023a)

Conventional biofuels are made from food crops such as corn, sugar cane and vegetable oils, whereas advanced (or second-generation) biofuels use non-food feedstocks such as agricultural/forestry residues, non-food crops or organic/industrial waste streams. Advanced biofuels also have lower lifecycle GHG emissions, e.g. from reduced land-use impacts compared to conventional biofuels (ITF, 2021b) and are therefore more sustainable. However, expanding bioenergy supply faces constraints and potential trade-offs with sustainable development goals, particularly in avoiding local conflicts over land use, such as for food production and biodiversity conservation. Only 12% of current biofuels are advanced biofuels, with the remainder based on feedstock that could be used for food production (IEA (2023a)). A significant increase of biofuel supply from today's level could result in competition between food and fuels (WRI, 2015) and impact food markets (IISDI, 2012).

Estimates from literature, including meta-studies reviewing multiple papers, international organisations and integrated assessments (see list in Annex A), indicate that the maximum available supply of bioenergy will vary from 60-313 EJ in 2050. There is no standardised methodology in the literature to estimate the technical potential. Most recent studies only refer to advanced bioenergy, excluding deforestation or biomass used for essential needs, such as food, feed or fibre (Creutzig et al., 2015). All values from the literature used in this report refer to advanced (or secondary) bioenergy, which also includes and prioritises the use of advanced bioenergy for essential needs.

It is of utmost importance from an environmental and social sustainability perspective that these guidelines for the use of bioenergy are also adhered to in the future. Food and energy crops should not be substantially increased if this could lead to deforestation and biodiversity loss in large monocultures. It is important to maximise the use of residual products, while also ensuring that soils are not completely stripped of crop residues, which play a crucial role in maintaining soil health (Cherubini et al., 2018). The literature refers to this balance as a "sustainable collection rate" for agricultural residues. Based on those paradigms, the technical potential is mostly restricted to advanced bioenergy. Some global legislation promoting the use of biofuels in transport, such as ICAO's CORSIA scheme, have requirements on the carbon intensity of the fuels rather than strict definitions of the pathways used. Should food-based feedstocks be used to make biofuels, strict environmental and social governance criteria should be met to avoid unintended consequences.

These values comprise the total primary biomass available for all sectors. The share of liquid or gaseous biofuels used in road transport has historically accounted for a relatively small fraction of the total, at close to 10%, or 8EJ. The remainder includes modern solid bioenergy, biomass lost in the conversion to biofuels and traditional uses of solid biomass, which is used in emerging markets and developing economies for heating and cooking).

While literature values on total sustainable available supply vary significantly, the share of gaseous and liquid biofuels in the primary bioenergy supply are relatively constant (10–15% and 10–20% of the total, respectively) (IEA (2023a), IRENA (2023)).

Bio-methane can offer significant reductions in GHG emissions compared with fossil fuels, if produced from sustainable feedstocks (Noussan et al. 2024, IRENA, 2018). Producing biomethane from manure or municipal solid waste generally offers the lowest carbon intensities of around 5 gCO_2/MJ, while corn feedstocks can be above 20 gCO_2/MJ. Additional differences depend on the carbon intensity of the electricity mix used.

However, biogases can also be used in a range of sectors, some of which have few technological alternatives for decarbonisation, such as for producing high-temperature heat or to decarbonise existing gas demand for residential heating during the transition to heat pumps. The IEA NZE scenario includes ambitious levels of adoption of biogases at 6–7 EJ globally by 2030, but current forecasts are for just one-third of this level by 2028 (IEA, 2023d). The IEA NZE scenario sees biogas use reach 15 EJ by 2050 (of which 10 EJ are biomethane), with the vast majority used as a substitute for existing natural gas use, particularly in the power sector and for industrial heat purposes with no significant use in the transport sector, since this other sectors can make better use of existing infrastructure compared to the transport sector.

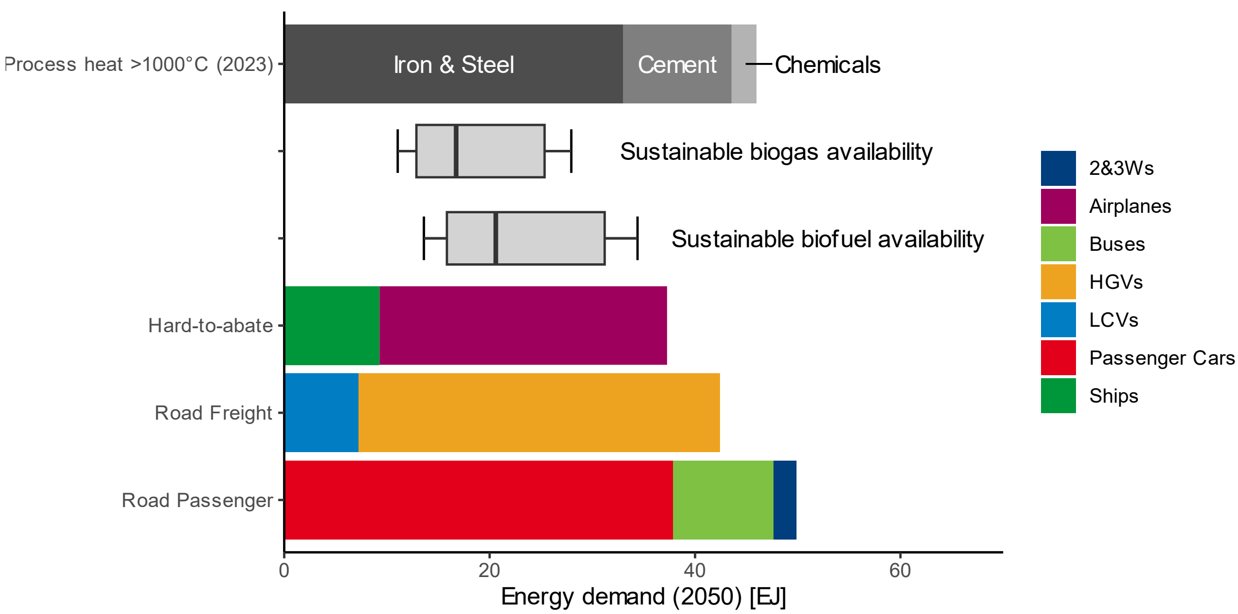
Significantly deploying new gas infrastructure in the transport sector has the risk of extending the use of fossil methane rather than displacing it – with the risk of locking in fossil fuel demand (TE, 2022). In 2021, biomethane accounted for only 20% of the energy consumption of CNG/LNG vehicles, with the remainder being conventional fossil fuels (IEA, 2023d).

Figure 3 shows the hypothetical bioenergy demand for the entire transport sector in 2050, based on transport demand from the ITF Transport Outlook 2025 ITF (forthcoming), if all vehicles used biofuels and biomethane. This is then compared with the potential sustainable biofuel and biogas supply in 2050 based on the sources cited above (listed in Annex A), assuming average shares for gaseous and liquid bioenergy. This comparison shows potential transport energy demand is higher than the optimistic potential supply of biofuel and biogas globally. The supply of sustainable biofuels is even likely to be insufficient to decarbonise the shipping and aviation sectors by 2050.

The figure also compares the sustainable biogas supply by 2050 with current energy demand for high-temperature process heat (>1000°C) from the three largest industrial applications (iron & steel, cement and chemicals). High-temperature heat for industrial applications is currently provided by burning fossil fuels, such as coal or natural gas. While there are alternative solutions on the horizon, high-temperature heat could be provided by biogas, where no competitive alternatives exist (FCA, 2024a). Since many of today’s applications use natural gas and the related gas infrastructure, biogases will be a likely use-case to decarbonise remaining high-temperature applications, compared to applications in the transport sector, where infrastructure would need to be deployed first.

Figure 3 compares bioenergy demand taking a global approach. However, on a regionally disaggregated level, the pool of available feedstocks may differ, particularly if the above-mentioned sustainability paradigms are considered. Europe accounts for almost half of currently available biogas production (approximately 0.7 EJ in 2021) (IEA, 2023d) and recent RePowerEU ambitiously targets to scale up European biomethane production to 1.33 EJ (35 bcm) by 2030 (European Commission, 2022).

Figure 3. Supply of sustainable biofuel and biogases versus hypothetical demand in 2050



Note: Current energy demand from process heat only refers to energy-related emission from process heat (above 1000 °C) from the three biggest industrial applications (cement, iron & steel and chemicals). Data and methodology is specified in the Annex A. It is assumed that 16% and 13% of the total available sustainable bioenergy is available in liquid and gaseous form respectively (see references listed in Annex A). Transport energy demand is taken from the 2025 ITF Transport Outlook's high ambition scenario (ITF, forthcoming) assuming all vehicles used biofuels. 2&3Ws= two and three wheeled light duty vehicles, LCVs= light commercial vehicles, HGVs= heavy goods vehicles, EJ= exajoules.

Sources: Based on IEA (2023a), IRENA (2023), (FCA, 2022), ITF (forthcoming).

Some biofuels come with the high risk that indirect land-use change can result in more carbon emissions than savings, compared to conventional fossil fuels (European Commission, 2019). Nearly all feedstock from used cooking oils or animal fat is used to produce biodiesel (ICCT, 2024). However, within the European Union, some producers have been mislabelling unused vegetable oil as used cooking oil to qualify for policy subsidies (European Commission, 2020). A recent ICCT study on the sustainability of feedstock for ReFuelEU found that it is crucial to broaden investment beyond the near-term focus on processing waste fats and oils, into other sustainable feedstock supplies (including municipal solid waste, agricultural waste and forest residues) to meet the requirements of the ReFuelEU aviation regulation (ICCT, 2024). The same analysis also warns that supplies of municipal solid waste, may decrease with the EU's Waste Framework Directive defining targets for recycling or if used cooking oils are restricted to domestic production for improved governance.

In the European Union, sustainable feedstock is sufficient to meet ReFuelEU's targets for bio-SAF in 2035, in part because waste animal fats and cooking oils can be used as input to existing hydrotreated esters and fatty acid (HEFA) production plants, currently the only commercially available technology pathway. Meeting 2050 targets will be more challenging since this includes wide deployment of technology pathways, e.g. the Fischer–Tropsch process, that can use sustainable feedstock, such as agricultural residues, but is currently not available at a commercial scale.

While it is clear that biofuels will be part of the low-carbon energy mix for transport, the combination of sustainability-related challenges and risks of fraudulent traceability may trigger policy developments that further restrict availability. For example, the EU introduced a cap on the supply of used cooking oil at 3% of aviation fuels and 1.7% of all transport fuels. This consideration underscores that sustainably sourced biofuels will only be able to cover a portion of transport energy demand by 2050. They should, therefore, be prioritised for applications or sectors particularly in need.

Synthetic fuels and carbon capture technologies

Synthetic fuels, or electro-fuels (e-fuels) are produced using electricity as the primary energy source. There are various different types of e-fuels and they include e-ammonia, or carbon-based synthetic fuels such as e-methanol, e-kerosene, e-gasoline and e-methane. All e-fuels contain hydrogen as a main energy vector and carbon-based fuels use an additional carbonaceous source, such as CO_2. Even though the main component of these fuels is hydrogen, e-fuels are treated as a resource in their own right, since they are subject to other challenges in scaling up or in their long-term sustainability potential.

Most carbon-based fuels are blended fuels which can be used in existing technologies with minor modifications to the engine or fuel delivery system. These fuels are of critical importance for the decarbonisation of transport modes that require energy-dense fuels, such as maritime shipping and aviation, where electrification is not possible over long distances. E-ammonia and e-methanol are among the low-carbon fuels being considered for shipping, while e-kerosene produced via the Fischer-Tropsch process is the most likely low-carbon alternative to conventional jet fuel (ITF, 2023b). The production of e-fuels is highly energy intensive, mainly due to its need for electrolytic hydrogen. The potential for GHG emission savings strongly depends on the carbon intensity of the electricity mix and the carbon source. Different carbon capture technologies and their potential to be sustainable will be further discussed in the second part of this chapter.

The current production of these synthetic fuels is limited to demonstrator projects and there are many challenges related to scaling up supply, since technology is still in the relatively early stages of readiness. There have not yet been any FIDs for projects at the gigawatt scale. The largest project announced for 2040 is led by Sasol South Africa with a capacity of around 30 megawatts, however, the carbon source is not clear, raising questions on its carbon-saving potential (PIK, 2023). Announcements concerning the production of synthetic fuels by 2030 add up to around 20 Mt of H_2-equivalent, the majority being ammonia. Only the projects with 1.8 Mt H_2-equivalent are Fischer–Tropsch fuels that could be used to replace fossil kerosene, which translates into 1.6% of the global jet fuel demand for 2023. However, only 7% of these projects have obtained FID (IEA, 2024b).

There is currently very little demand for e-fuels and due to high costs this will be limited to areas of the world where its use will be mandatory in the near future. The EU's PtL jet fuel mandate under ReFuelEU requires increasing shares of synthetic fuels in aviation, growing from 1.2% in 2030 to 35% in 2050. The mandates include substantial penalties for non-achievement, up to twice the price of kerosene. There are no other regions outside the European Union with binding mandates on the use of synthetic fuel for aviation.

Currently, the costs of synthetic kerosene are between seven and twenty times higher than their fossil counterparts (IEA, 2024b; IRENA, 2024). Economies of scale have the potential to reduce costs but will be more expensive than fossil Jet A fuel in the long term. However, the impact on ticket prices remains relatively moderate with an 8% cost increase by 2030 including fuel blending mandates of 1.2%, according to ReFuelEU (IEA, 2024b).

E-fuels are a key resource in the decarbonisation of the economy, with particularly high potential in hard-to-abate sectors such as maritime shipping and aviation. However, current supply levels are negligible compared to demand from scenarios compatible with climate targets. For example, even if all global projects announced for 2035 were completed, they would only be able to meet 10% of the 2019 demand in Germany in sectors where the switch is unavoidable, such as international shipping, aviation and chemical feedstocks (PIK, 2023).

Carbon capture technologies

Carbon capture technologies are essential for producing low-emission fuels for high-energy applications such as aviation and shipping that require carbon as a feedstock. These technologies vary as to the carbon source (i.e. atmosphere or industrial flue gases) and its destination (i.e. used or permanently stored). Carbon capture technologies are also essential for capturing unavoidable process emissions (e.g. in cement production) in a net-zero economy, ultimately reducing atmospheric CO_2 levels. An increasing number of global net-zero scenarios rely on carbon capture and e-fuel technologies (IEA, 2023c, 2023e; IPCC, 2022), as well as emission forecasts from hard-to-abate sectors, such as aviation, shipping and industry. Various possible pathways exist to capture carbon, yet they differ significantly in their degree of circularity. Carbon can be recaptured from biogenic sources (e.g. combustion from biogases), from industrial point sources (e.g. fossil power generation or cement production) or from the atmosphere.

Since (re)capturing CO_2 is very energy intensive the potential for emissions savings also strongly depends on the carbon intensity of the energy mix used. Consequently, the emission savings potential of any subsequently produced e-fuel is subject to the origin of the carbon feedstock and what would happen to it in the absence of the carbon capture process. For example, biogenic sources, such as gases released during fermentation (e.g. from the production of ethanol) result in lower life-cycle emissions, thanks to atmospheric sourcing of the carbon contained in the biomass. Conversely, carbon capture and utilisation (CCU) from fossil fuels, from combustion or process emissions – including from steelmaking and cement production – can reduce life-cycle emissions of up to 50% at best, for example, if a unit of carbon is used twice before ultimately being emitted into the atmosphere.[3], [4]

Direct air capture (DAC) is an alternative technological approach to biogenic pathways and carbon capture from point sources. Based on atmospheric CO_2 removal at ambient atmospheric concentrations, DAC relies on a chemical adsorbent to separate CO_2 from other atmospheric gases (McQueen et al., 2021). These absorbents selectively bind to CO_2 and strip it off, using heat, changes in pressure (or both) or electrochemical swings, after which the concentrated CO_2 can be recovered and the adsorbent reused. DAC can play into global climate policy in two main ways.

- DACCU – DAC with Carbon Utilisation. In this approach, DAC is used to capture carbon from the atmosphere and use it as a feedstock for the synthesis of carbon-containing e-fuels. These include e-methanol, e-kerosene, e-diesel and e-methane. Fuel production also typically requires a source of hydrogen (Concawe, 2023; FFV, 2021). If both hydrogen production and DAC processes use low-carbon energy, these fuels can have low life-cycle emissions.

- DACCS – DAC with Carbon Sequestration. In this approach, carbon captured from the air is permanently sequestered, most commonly via injection of CO_2 into geologic storage sites, where it converts to stable non-gaseous forms (ICEF, 2018).[5] This approach is often referred to as "net removal" because it reduces atmospheric concentrations of CO_2. This second approach may also serve the purpose to offset emissions from another activity.[6]

Due to the low concentration of CO_2 in the atmosphere, all DAC-based technologies need to process extremely large masses of air: 1.6 tonnes of air for every kilogramme of CO_2 captured, or over 2 400 m^3 of air per m^3 of CO_2 captured, excluding losses from selective CO_2 removal of the chemical absorbent. To put this into perspective with the respective fuel: over 4 tonnes or 3 000 m^3 of air at standard ambient pressure and temperature would be needed to produce one litre of diesel or offset the emissions via DACCS[7]. This would compare to a one-metre diameter fan operating for one hour, under typical operating conditions. See Annex A for more details and assumptions.

Table 3 compares a fossil fuel benchmark – based on production and combustion of petroleum fuels – and other e-fuel production pathways with the three roles of DAC in the climate policy portfolio: reducing atmospheric concentrations of CO_2 via DACCS (essentially creating a negative GHG emission rate) and providing key inputs for the synthesis of liquid or gaseous fuels.[8] The table shows that both DACCS compensating emissions from fossil fuel production (used here as a reference for DAC plus CO_2 sequestration technologies) and DAC followed by e-fuel synthesis are energy intensive processes, requiring almost twice (for DACCS with offsets) or more than twice (for DAC to e-fuels) the amount of primary energy contained in the fuel to be completed.[9]

Table 3. Energy intensity and GHG emission potential from different applications of DAC and other competing options, with a focus on solutions with high life-cycle GHG emission abatement capacity

	GHG emissions (g CO_2/MJ)	CO_2 saved (% of benchmark)	Total primary energy needs (MJ/MJfuel)	Fossil energy needs (MJ/MJfuel)	Primary heat needs (MJ/MJfuel)	Primary electricity needs (MJ/MJfuel)	Total primary energy needs (MJ/kg CO_2 saved)	Fossil energy needs (MJ/kg CO_2 saved)	Primary heat needs (MJ/kg CO_2 saved)	Primary electricity needs (MJ/kg CO_2 saved)
Fossil fuel benchmark	89		1.2	1.2	0.0	0.0				
DACCS							8.6	0.0	7.4	1.2
Fossil fuel benchmark + DACCS (no upstream abatement)	27	70%	1.8	1.2	0.5	0.1	25.3	16.8	7.4	1.2
Fossil fuel benchmark + DACCS (with upstream abatement)	9	90%	1.9	1.2	0.6	0.1	26.9	16.8	8.7	1.4
Fossil fuel (e-refining) + DACCS	9	90%	1.8	1.0	0.5	0.3	25.3	13.9	7.4	4.0
E-H_2 (production only)	5	94%	1.4	0.0	0.0	1.4	16.1	0.0	0.0	16.1
E-H_2 (with storage, transport and distrbution losses)	6	93%	1.6	0.0	0.0	1.6	19.3	0.0	0.0	19.3
E-ammonia	5	94%	1.7	0.0	0.0	1.7	20.1	0.0	0.0	20.1
DAC to e-fuel (methane)	9	90%	2.1	0.0	0.2	1.9	26.3	0.0	2.2	24.1
DAC to e-fuel (methanol)	7	92%	2.2	0.0	0.1	2.1	26.5	0.0	0.9	25.6
DAC to e-fuel (methanol to kerosene)	8	91%	2.3	0.0	0.1	2.2	28.6	0.0	1.2	27.4
DAC to e-fuel (FT to diesel or kerosene)	9	90%	2.7	0.0	0.3	2.4	34.1	0.0	4.1	30.0

Note: E-refining is assumed to rely on electricity for a fraction of energy needed for all upstream activities related to fuel production; electricity for e-refining is assumed to be zero carbon. Upstream abatement refers to the use of DACCS not only to offset direct emissions from fossil fuel combustion, but also emissions associated with their extraction and refining processes.

Sources: Concawe (2023) for all e-fuel options, supplemented by IEA (2020) for DACCS (average values between direct air capture with storage based on liquid and solid sorbents[10]), Bothe et al. (2021) for storage, transport and distribution losses for hydrogen and Deutz and Bardow (2021) for life cycle GHG savings from DACCS, assuming very high shares of very low-carbon electricity – consistently with Concawe (2023), for e-fuels. Energy needs per kg CO_2 for DAC in the DACCS for offset case are converted from CO_2 emission to energy requirements per MJ of fuel considering 3.1 kg CO_2 per kg of fuel and 43.3 MJ of fuel per kg.

Table 3 indicates that all processes reliant on DAC can be effective in mitigating life-cycle GHGs, as it is developed based on the condition that they rely strictly on low-carbon primary heat and primary electricity supply.[11] It also shows that electrolytic hydrogen production could be more energy efficient, even when counting for transport and distribution infrastructure, as long as the infrastructure can be effectively used,[12] and that life-cycle energy needs for hydrogen are closely followed by e-ammonia (one of the options currently considered as an alternative, low-carbon shipping fuel).

Table 3 also shows the differences in the energy mix required and in the extent to which each option relies on fossil energy. In this respect, it points out that:

- DACCS represents a direct route to net removal of CO_2 from the atmosphere which requires very large amounts of heat and limited amounts of primary electricity. Using DACCS to offset fossil emissions requires primary heat inputs several times greater than fossil energy to offset the emissions.
- DAC-based and other e-fuels can also lead to major life-cycle emissions abatement, but with very high requirements of low-carbon primary electricity, complemented by smaller but still sizable amounts of primary heat, although not requiring direct fossil energy inputs.[13]

The very large need for low-carbon (and low-cost) electricity required by e-fuels (especially as hydrocarbons) represents a constraint for the quantity of fuel that can be produced, due to the need for large amounts of generation capacity. This adds to the decarbonised electricity generation capacity necessary to simultaneously reduce the carbon intensity of electricity production and satisfy additional demand from energy-efficient heating and road transport applications, such as heat pumps and electric vehicles. It also adds to the challenge, shared by DACCS, of processing large volumes of air.

Further challenges arise from the greater GHG benefits and fossil fuel savings that could be gained by connecting the electricity generation capacity required for DAC to e-fuel options to the grid, reducing thermal generation, thanks to energy efficiency advantages that are not available if e-fuels displace petroleum fuels. As DAC and e-fuel systems improve their efficiency, and as electrical grids around the globe decarbonise, the relative benefits of using electricity to produce liquid fuels will grow[14]. This challenge, also shared by the production of electrolytic hydrogen (despite better energy efficiency than e-fuel production processes), needs to be addressed by specific policy requirements on temporal matching, additionality and deliverability.

Access to the low-carbon (and low-cost) primary heat (which can also be extracted with heat pumps, e.g. from geothermal or solar heat resources[15]) is also a crucial requirement for DACCS processes, even though they generally have lower electricity needs in comparison with DAC to e-fuels pathways.

The need to access low-carbon primary energies for DACCS, similarly to e-fuels (although not to the same scale), highlights a primary limiting factor to the continued reliance on fossil energy. DACCS structurally links residual emissions (and in the case of offsetting, far higher GHG emissions from fossil energy use) to vast amounts of primary energy resources (i.e. primary heat[16] and electricity), necessary to enable the atmospheric carbon removals. Given likely limitations on the rate of deployment for low-carbon electricity, and the much larger amounts of primary heat needed for offsetting cases, it is clear that the use of DAC to offset fossil fuel emissions will be limited, in comparison with DACCS, in its contribution to meeting medium-term GHG targets and the net removal of residual emissions arising from a shift to alternative, low-carbon fuels.

Additional limitations may arise for DACCS technologies (as well as industrial CCS), from technical, contractual and regulatory barriers, as these may restrict practical CO_2 storage potential. For example, in most CCS applications, the rate of CO_2 injection is limited by the rate at which supercritical CO_2 can diffuse into its surroundings. At present, due to the relatively low investment and activity on geological CO_2 storage, there is significant uncertainty regarding the sustainable rate at which CO_2 can be pumped underground and it could be that the maximum global injection rate may be restricted (E3G, 2023; Lane, Greig and Garnett 2021).

DAC technologies are in an early stage of adoption and currently have a very low supply of around 0.01 Mt CO_2/year (Ozkan et al., 2022) and a current global capture capacity equivalent to about 0.1% of energy-related emissions (Bloomberg UK, 2024). While there are significant future supply announcements (65 Mt CO_2/year) that almost align with IEA NZE scenarios for 2030, few projects have reached FID status. The future demand for DAC remains uncertain, as costs are currently still high (Bloomberg UK, 2024; Trinomics, 2023) and their development will depend on technological progress, with greater chances for cost reductions with a supporting research and deployment policy framework, adding additional constraints to the availability of carbon-based e-fuels.

A merit order to manage resource scarcity

The previous chapter showed that key resources required to decarbonise the economy will be relatively scarce in a transition compatible with climate targets as their supply scales up. To manage scarcity, governments should help to increase supply, promote energy efficiency and other aspects of circularity to decrease demand, but this may not be sufficient within the necessary timeframe.

In general, market conditions and competition for energy resources between sectors can help minimise costs. Current regulatory structures may not be set up to allocate resources to the sector requiring them most for decarbonisation, since not all new low-carbon technologies and resources can be used interchangeably, and some have a greater benefit if used in a specific sector. In many cases, energy resources are not optimally allocated to ensure the best climate outcomes because negative externalities are not priced in. Allocation is driven by economic value, favouring individual market actors or sectors with greater purchasing power rather than those with the most critical needs for decarbonisation.

Government policies are important to help overcome market failures and better allocate resources. Policies and regulations, including carbon pricing and fuel taxation, can help to “price-in” negative externalities and support essential new technologies.

However, government policies can also create distortions that negatively impact the optimal allocation of resources. Decarbonisation policies are often designed for individual sectors or applications and lack a cross-sectoral perspective. Taxes in the road transport sector are generally far higher than in the aviation and shipping sectors. Road transport policies are often decided nationally, compared with aviation and shipping, which require further international agreements. Similarly, policies such as biofuel blending mandates are often sector-, or region-specific (e.g. for road transport) and thereby lack a holistic approach to decarbonising all sectors of the economy.

To guide governments in making regulatory decisions and to give clarity to the market, governments should communicate and enact regulations based on a merit order: a method for ranking and allocating scarce resources based on sectoral prioritisation to ensure better outcomes with limited resources. Ideally, this should be done in co-ordination with other countries to best allocate resources internationally.

An overarching, cross-sectoral merit order for resource use at the government level would facilitate better alignment of policies from different sectors. Its implementation can tip the market by indicating a preferred technological solution while communicating to other sectors that they may require alternative technological solutions for decarbonisation if they are at risk of being priced out of the market. It provides transparent resource prioritisation for each application, which can create market certainty for companies and investors, accelerate the adoption of the most suited technologies and create synergies between sectors.

There are many different ways to use a merit order. The electricity market uses one of the most known ones, where a merit order principle is used to rank power production facilities based on their marginal costs of producing electricity to meet demand. Power plants with the lowest marginal costs, such as those with the lowest fuel expenses (e.g. solar PV, wind or hydropower), are prioritised by the market operator and given dispatch signals to supply electricity to the grid first. As demand increases, power plants with higher marginal costs are brought online to meet the additional demand. The merit order helps ensure that electricity is supplied in the most economically efficient way by using the cheapest available sources first.

A merit order to prioritise the use of scarce resources can depend on various factors, ranging from technological constraints to cost considerations and the long-term potential to be sustainable. The following sections introduce several metrics to inform such a merit order.

Different ways of prioritising energy resources

Some sectors of the economy have relatively few technological options for decarbonisation. Long-distance aviation needs to have an energy-dense fuel, for which alternative kerosene is the prime option in the short to medium term, given the low technology readiness of hydrogen planes and the significant time that would be needed to replace the aircraft fleet. Alternative low-carbon kerosene can be produced with advanced biofuels or synthetic fuels from atmospheric CO_2 and hydrogen (ITF, 2021b).

Similarly, decarbonising high-temperature heat processes in industry favours low-carbon liquid or gaseous fuels since electrification is not yet a viable and scalable option. Conversely, some sectors can use multiple technologies. For example, the technological mitigation options for heavy-duty road freight include direct electrification using batteries and/or electric road systems, hydrogen through fuel-cells or an internal combustion engine, or advanced biofuels and synthetic fuels. However, not all these solutions may be equally well suited to decarbonising this sector.

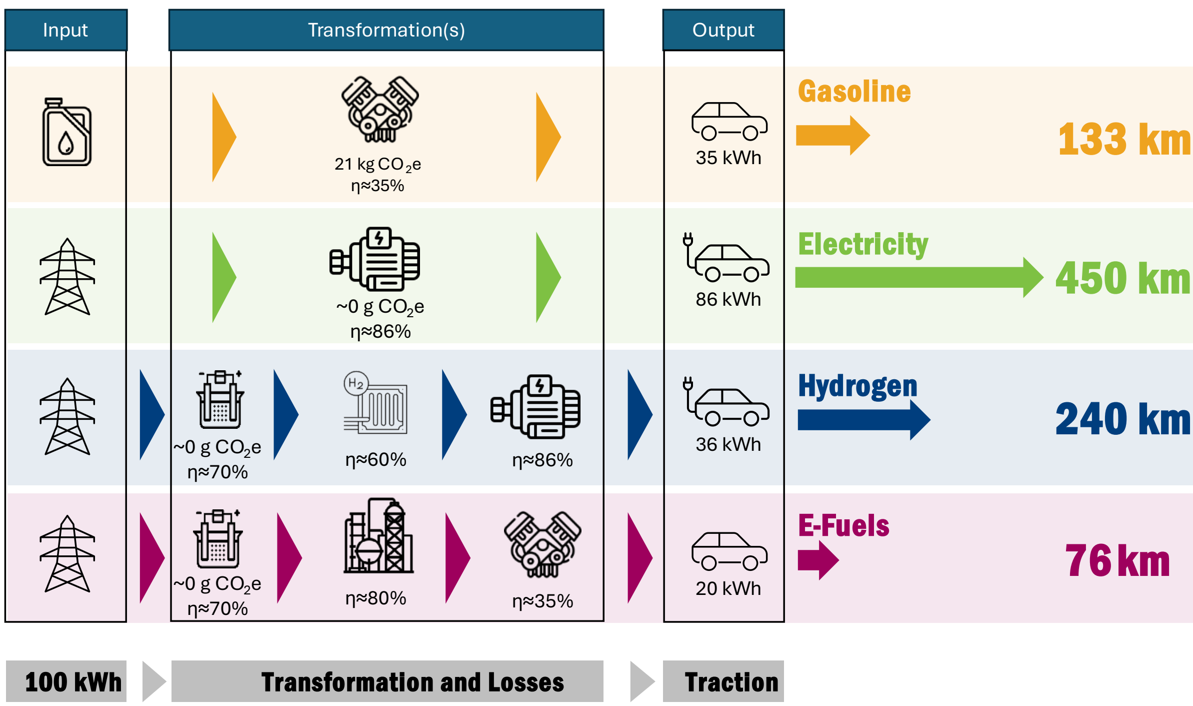
Scarce energy resources should be prioritised for sectors in which there is no alternative technology to decarbonise. These technological limitations should be considered when developing a merit order. However, it is often unclear which sectors should be prioritised for the use of a limited energy resource based purely on technological compatibility. Should hydrogen be prioritised for making aviation fuels or for decarbonising steel? To further prioritise the use of energy resources, certain metrics can be used, including the GHG emissions savings per unit of energy, marginal abatement costs and the willingness to pay. The following sections will provide an overview of these metrics and how they can contribute to establishing a merit order.

GHG savings per unit of energy

One way to prioritise the use of scarce energy resources, such as renewable electricity and green hydrogen, is to maximise the GHG savings from their use. A kilowatt hour (kWh) of low-carbon electricity can be used in various sectors, transport modes and devices to replace fossil fuels. However, the GHG emissions savings differ significantly between different applications based on the energy efficiency of the process and the GHG emissions intensity of the avoided fuel.

Different energy technologies can also vary in their energy efficiencies, where each additional conversion process deteriorates the overall efficiency. If technology alternatives, e.g. vehicle powertrains such as FCEV, BEV or ICE using e-fuels were to replace the conventional gasoline internal combustion engine (ICE-G), their use could be prioritised according to a merit order, as energy efficiencies are directly correlated with the GHG emissions savings. Figure 4 shows the energy conversion steps for various vehicle powertrains with the same energy input of 100 kWh. The overall efficiencies strongly depend on the powertrain and can vary by more than a factor of five between direct electrification and e-fuels.

Figure 4. Conversion efficiencies for various engine technologies with the same amount of input energy.



Note: Energy efficiencies from (ITF, 2021a). ICE = Internal combustion engine; -G = gasoline; e-fuels = electro-(synthetic)fuels, assuming e-gasoline; BEV = Battery electric vehicle; FCEV = Fuel cell electric vehicle. Storage and distribution losses neglected for hydrogen pathways. Transmission and distribution losses for electrification pathways are neglected, engine efficiencies include AC/DC conversion losses from the battery. Heat demand for direct air capture (DAC) in hydrocarbon synthesis is entirely supplied by waste heat from integrated systems of electrolysis and hydrocarbon synthesis.

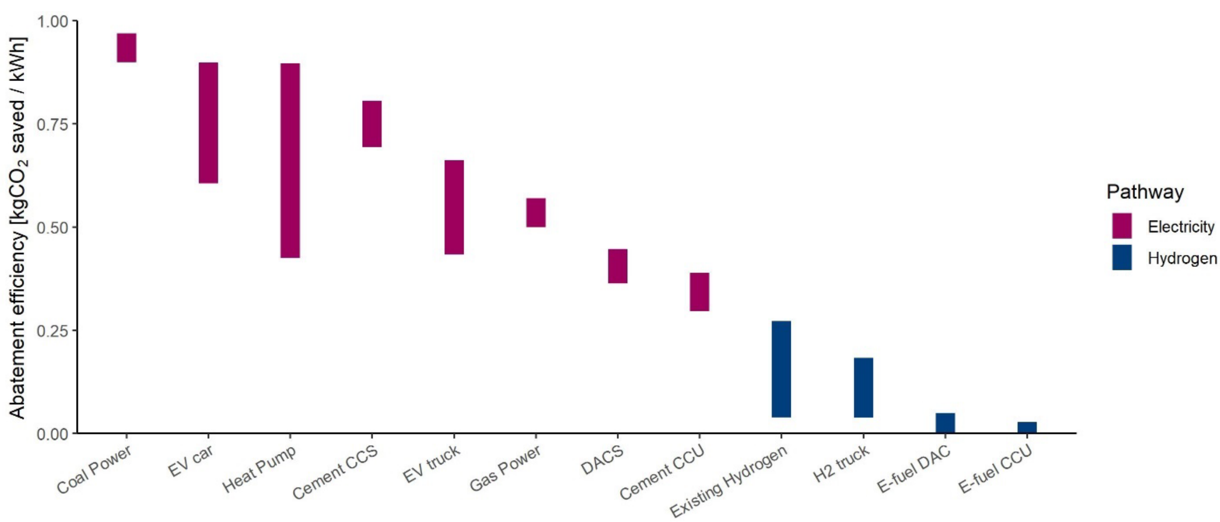
Figure 5 shows the GHG reduction from using renewable electricity in different end-use applications. One of the best uses for a kWh of renewable electricity is in replacing unabated coal use in power generation since it leads to significant emission savings. The carbon intensity of unabated coal electricity is approximately 1 kg CO_2/kWh, so replacing it directly with renewable electricity could save 1 kgCO_2 per kWh of renewable electricity used. Conversely, using renewable electricity to produce green hydrogen for use in power generation is a far less efficient use of energy due to the low conversion energy efficiency of hydrogen production. Producing hydrogen with an electrolyser leads to energy efficiency losses of 30–50%. The hydrogen then needs to be transported and compressed, which leads to further losses. This means it takes roughly two to three units of electrical energy to produce one unit of hydrogen energy.

Therefore, using hydrogen to replace coal-fired power generation would only save around 0.5 $kgCO_2/kWh$ of renewable electricity used.

In the mobility sector, there are various ways to use renewable energy resources to decarbonise transport. Electricity could be used to produce green hydrogen via electrolysis, which could then be used in a fuel cell in a vehicle. Alternatively, the electricity could be used to collect CO_2 using direct air capture (DAC) and combined with hydrogen to create a synthetic hydrocarbon efuel, which could then be used in a conventional internal combustion energy vehicle. A third option is to use renewable electricity directly to charge a battery electric vehicle (BEV). In general, the fewer the conversion processes, the greater the energy efficiency and thus, the greater the possible GHG emission savings. Electrolysers to produce green hydrogen, internal combustion engines and fuel cells are inefficient energy conversion processes, meaning more energy is required to achieve the same emissions benefit.

The direct electrification of end-use applications (e.g. residential heat pumps or electric vehicles) has relatively high GHG savings per kWh of electricity. Conversely, producing synthetic hydrocarbon renewable fuels of non-biogenic origin (RFNBO) for use in road transport is far less effective at saving GHG emissions due to the multiple energy inefficient conversion processes.

Figure 5. Prioritisation by GHG emissions savings per unit of energy



Note: CCS = Carbon Capture and Storage, CCU = Carbon Capture and Utilisation, DAC = Direct Air Capture, Coal/Gas power refers to the carbon savings from replacing one unit of coal/gas-fired electricity with renewable electricity. EV car/EV truck/H_2 truck refer to the direct carbon emission savings from replacing a conventional fossil fuel vehicle with the new technology powered by low-carbon electricity. Ranges refer to different electricity carbon intensities: Low = 30 g CO_2/kWh, High = 100 g CO_2/kWh, and additional technological uncertainties (see Annex A).

Low-carbon synthetic hydrocarbons are made with captured carbon. This can help to offset the CO_2 emissions when they are burnt. The carbon intensity of synthetic fuels depends on the emissions intensity of the electricity and the source of the carbon feedstock used. If low-carbon electricity is used to produce the green hydrogen and to source the CO_2 using DAC and waste heat, then the synthetic kerosene can also be low carbon since the carbon captured from the atmosphere offsets the emissions from burning the fuel. Alternatively, the carbon for synthetic fuels can be sourced from industrial capture units (CCU) in the chemical, cement or power generation sectors. Since much of the CO_2 produced by these industrial sectors comes from the burning of fossil fuels, reusing the waste CO_2 from these sectors will still lead to a net addition of CO_2 to the atmosphere. This means synthetic fuels produced using industrial carbon capture will be challenging to consider as low carbon, although they could offer some marginal benefits compared with the continued use of fossil kerosene (ITF, 2023b). Using an industrial source of carbon could potentially help to scale up synthetic hydrocarbon fuel production in the period until DAC is more widely available. However, it is not a given that synthetic e-fuel facilities located near industries using fossil fuels will be able to easily transition to biogenic or DAC carbon feedstocks in the future due to geographical constraints.

From an energy-efficiency perspective, recapturing industrial point source CO_2 emissions, such as process emissions from cement production, is relatively efficient (Figure 5). The levelised costs of cement CCU for the conventional carbonation process could be within the range of current selling prices (Strunge, 2021), despite the additional costs of storage. Since cement production will also rely on carbon capture in the long term and assets can therefore be used in the long term, the adoption of this technology is a high priority. Note that cement CCS assumes that 100% of the carbon credit remains with cement. The carbon abatement effectiveness halves if carbon credits are shared 50/50 with the downstream utilisation (Figure 5).

When renewable energy resources are scarce it makes sense to use the most efficient process where possible. Using this method of prioritisation, direct electrification of end uses is generally ranked highest in this merit order. Focussing on directly electrifying mobility rather than using hydrogen or e-fuels can contribute to managing the scarcity of renewable energy in the short term. In the long term, when renewable electricity is abundant, other more energy-intensive uses can be given greater consideration. This ranking would also suggest that electrolytic hydrogen should be prioritised for decarbonising existing hydrogen uses, where they can have greater GHG savings, rather than using them for producing efuels or hydrogen for the mobility sector where other alternatives, such as electrification exist. However, there are other factors to consider when using a merit order to prioritise the use of scarce energy resources. These include cost competitiveness, which is often compared using marginal abatement costs.

Marginal abatement costs

Marginal abatement costs (MACs) represent the cost associated with reducing a tonne of CO_2 emissions when replacing one technology or fuel with another. These costs differ between technologies and can change over time. MACs are calculated by dividing the differences in total cost of ownership and lifecycle GHG emissions of a new technology compared with that of the conventional fossil fuel alternative. For example, if a new technology costs USD 1 000 more than its fossil fuel alternative and can save 10 tonnes of CO_2 over its lifetime then its marginal abatement cost is USD 100/tonne CO_2. MACs can be negative when a low-carbon alternative is cheaper than its fossil fuel counterpart.

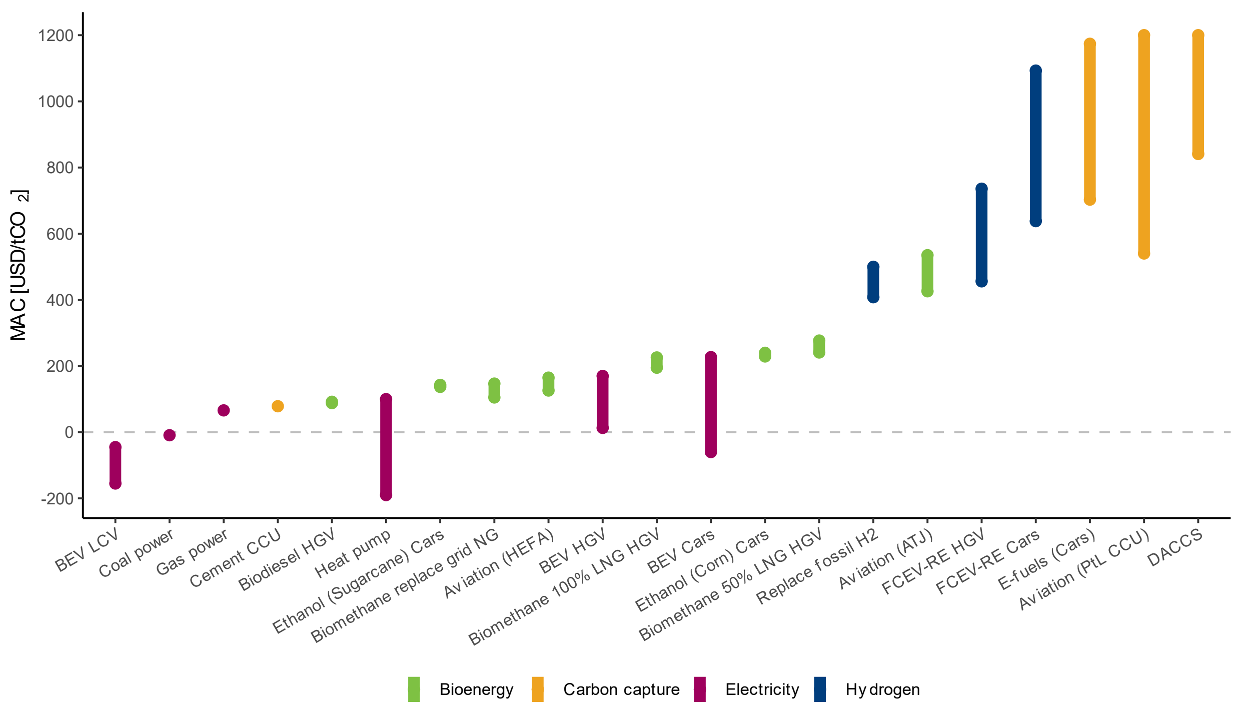
MACs are useful to compare the decarbonisation costs of different technologies. Figure 6 shows MACs for the different sectors and technologies (assuming global averages) today (approximately in 2024) and in the future (in 10 years time). Building new renewable electricity generation to substitute newly built coal or gas power generation are among the most cost-effective actions, with very low marginal abatement costs. Therefore, this should be one of the highest priorities since it is cheap and available today to decarbonise the global economy.

The MAC of heat pumps varies significantly with the electricity mix, their coefficient of performance and the technology that they are replacing. For example, the emission savings of replacing an oil-fired boiler is higher than replacing a boiler fired with natural gas, which results in a lower and potentially negative MAC.

Electric vehicles are roughly comparable with conventional vehicles on a total cost of ownership basis (their initial purchase cost remains higher, but lower operational costs can compensate; see Annex A).

Using the average global carbon intensity of electricity, electric vehicles can already save roughly 40% of the GHG emissions compared to their fossil counterpart over the lifetime (ITF, 2021a) with a small financial difference. This means their marginal abatement costs are relatively low. Light commercial vehicles have negative marginal abatement costs since they are already more cost-competitive on a lifetime basis than conventional vehicles (T&E, 2022), and their high annual mileage results in a relatively large lifetime GHG saving. The MACs for transport electrification options are estimated using average global grid carbon intensities over the lifetime of a vehicle purchased today and in a decade. This arguably makes the MACs relatively conservative compared with those of hydrogen and efuels (see below) which are assumed to be made only with renewable electricity.

Figure 6. Marginal abatement costs for various technologies across sectors



Note: See Annex A for methodology. BEV = Battery Electric Vehicle, LCV = Light commercial vehicle, HGV = Heavy goods vehicle, FCEV-RE = Fuel Cell Electric Vehicle using hydrogen produced with renewable electricity. CCS = Carbon capture and storage. CCU = Carbon capture and utilisation. LNG = Liquified natural gas. ATJ = Alcohol-to-jet. PtL = Power-to-liquid, HEFA = Hydrotreated esters and fatty acids. This figure examines the MACs to: substitute a diesel LCV with a BEV, substitute new-build coal power generation with renewables, substitute gasoline with sugarcane bioethanol, substitute new-build gas combined cycle power generation with renewables, capture and store cement process CO2 emissions, substitute a diesel HGV with a BEV, substitute HGV diesel with biodiesel, substitute domestic heating (oil, gas, direct electrification) with heat pumps, substitute fossil kerosene for aviation with HEFA, substitute grid natural gas for biomethane, substitute a gasoline car with a BEV, substitute a diesel HGV with an LNG HGV using 100% biomethane, substitute a diesel HGV with an LNG HGV using 50% biomethane/50% natural gas, substitute fossil steam methane reformation hydrogen with green hydrogen, substitute a diesel HGV with an FCEV using green hydrogen, substitute fossil kerosene for aviation with synthetic kerosene produced using carbon from industrial point sources (not DAC), capture atmospheric carbon using DAC.

Other technologies to decarbonise the road transport sector have comparable MACs today but will struggle to reduce over time in the same way that electrification technologies can. Sustainable biofuels from sugarcane ethanol have the potential for significant emissions savings compared with fossil fuels. Emission intensities are approximately 60% lower than those of gasoline (26 gCO_2/MJ direct (Cai et al.,

2022) + 10 gCO2/MJ indirect emissions (ICAO, 2024)). Ethanol produced using corn has emissions intensities only 35% better than fossil gasoline (52 gCO_2/MJ + 5.5 gCO_2/MJ of indirect land use change (Cai et al., 2022)). However, ethanol fuels currently cost 30% more than gasoline on an energy basis (US Department of Energy, 2024), meaning their marginal abatement costs are approximately USD 140/tCO_2 and USD 240/tCO_2 for sugarcane and corn ethanol respectively, with little scope for further reductions (IEA, 2023d). The MAC of ethanol for passenger cars is comparable to that of electric vehicles today (USD 230/tCO_2), but future expected reductions in BEV purchase costs will significantly reduce the MAC (Figure 6), although this varies by region based on the electricity cost and carbon intensity.

Biodiesel can help save emissions compared with conventional diesel fuel, when produced from sustainable feedstocks. Biodiesels produced using used cooking oil can have emissions intensities of 20 gCO_2/MJ with no indirect land use change emissions. However, these feedstocks are limited in availability. Conversely, using palm oils for biodiesels can have carbon intensities worse than fossil diesel. Fuels commonly used in Europe and the USA have carbon intensities roughly 60% better than fossil diesel (Cai et al., 2022, Prussi et al., 2020).

However, between 2019 and 2022, biodiesel was consistently more expensive than conventional diesel, costing 55% and 27% more in the United States and Europe, respectively (IEA, 2022). This means their marginal abatement costs are approximately USD 90/tCO_2. For heavy-duty trucks, electrification currently has a MAC roughly twice that of biodiesel, but has the potential to be cheaper than conventional diesel trucks in the near future, meaning in many applications, it could also be cheaper than biodiesel (ITF, 2022).

It is likely there will remain some particularly challenging use cases, such as very long-distance road freight or remote rail, where electrification is not feasible or will remain more expensive than biofuels. However, these challenging applications are likely to decrease over time with the maturing of vehicle technologies and improvements in battery energy densities (ITF, 2022).

Biomethane can be effective at reducing emissions from existing uses of natural gas. When it is injected into the gas distribution network to displace fossil gas, it could have a MAC of approximately USD 150/tCO_2 (assuming an average natural gas and biomethane costs of USD 6.5/MBtu and USD 14.4/MBtu, respectively (IEA, 2020b)). This is more expensive than using a heat pump (MAC of around USD 100/tCO_2 to replace gas-fired boilers and USD -190/tCO_2 to replace electric resistive heating), meaning that electrification is a cheaper way to decarbonise heat demand in the long-term, where it is technically feasible.

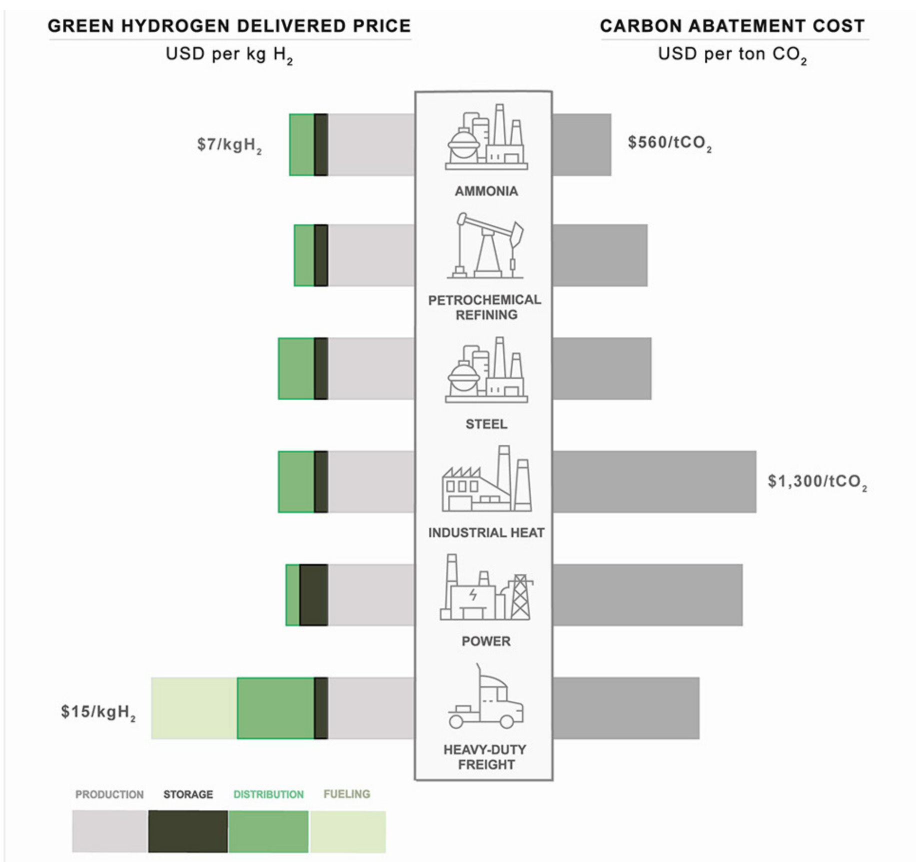
Biomethane could also be used to displace diesel in heavy goods vehicles. Using 100% biomethane in an LNG truck could have a MAC of around USD 225/tCO_2, which is higher than grid injection. Using a blend of biomethane with natural gas to power the truck would quickly further reduce the environmental benefits, thereby increasing the MAC. A 50/50% blend of fossil gas to biomethane would increase the MAC to USD 280/tCO_2. This means using biomethane to decarbonise road freight risks being relatively expensive compared with electrification if a share of fossil gas is used. Using biomethane to decarbonise existing uses of natural gas and focusing in the long term on particularly challenging applications where other technologies are not feasible or cannot compete, such as high-temperature heat or gas-turbine-based power generation for grid flexibility services, would be a more cost-effective decarbonisation pathway.

Hydrogen fuel cell electric vehicles, when using hydrogen made with renewable electricity (FCEV-RE), have far higher MACs ranging between USD 730/tCO_2 today to USD 450/tCO_2 in a decade (see Annex for methodology). If the hydrogen is produced with conventional steam methane reforming, which is the most common method used today, the MAC is over USD 1000/tCO_2. This pathway only offers meagre GHG savings compared with conventional fossil fuels and comes with a significant expense. Using green hydrogen produced with renewables (FCEV-RE) would have larger GHG emissions savings but still remains comparatively expensive. A full comparison of the total costs of ownership of different road freight technologies can be found in (ITF, 2022).

Figure 7 shows the MACs for different uses of green hydrogen. This shows that industrial uses of hydrogen, particularly in sectors with existing demands, have significantly lower MACs than in novel applications such as heavy-duty road freight, power or industrial heat. This is particularly due to differences in infrastructure costs for distribution and fuelling. Centralised, large sources of demand in industry have much lower hydrogen distribution costs than highly disaggregated and comparably small sources of demand in transportation, where hydrogen may have to be distributed over longer distances.

MACs can be useful to compare different abatement options across the economy and thereby help to guide government decisions about which sectors require the most financial support to decarbonise. The MACs of direct electrification of light road transport and residential space heating have low MACs. Other heavy industrial uses, such as chemical feedstocks or maritime shipping, become increasingly expensive to decarbonise using electrification alone and require alternatives such as biofuels or e-fuels.

Figure 7. Marginal carbon abatement costs for green hydrogen in different sectors



Source: Reproduced Shafiee and Schrag (2024)

MACs can be particularly useful for comparing the different sectoral uses of scarce resources. For example, waste cooking oils commonly used to make hydrotreated vegetable oil (HVO) fuels for heavy goods vehicles could, in many cases, also be used to make HEFA fuels for the aviation sector. Using these fuels today in the road freight sector is a relatively cost-competitive method for decarbonisation since it has a lower MAC compared with alternatives such as electrification. However, as BEV trucks become more cost-competitive, continuing to use HVO fuels for trucks risks restricting available supplies for HEFA fuels. Since the alternative SAF technologies to decarbonise aviation (such as power-to-liquid fuels) are considerably more expensive technologies, using HVO in trucks would lead to a net increase in global decarbonisation costs. Using ethanol as a substitute for gasoline in cars would have a similar outcome if it means there are insufficient fuels to make alcohol-to-jet fuels for the aviation sector.

MACs can help in identifying the lowest cost options to prioritise for cutting emissions, but this approach has limitations. A key challenge in comparing MACs is their inability to capture the interdependence of different sectors and technologies. The MACs shown in Figure 6 do not account for charging infrastructure costs, which are likely to be shared with other sectors in the case of transmission and distribution infrastructure. The cost of electric vehicle charging may also depend on the flexibility they can provide to the electricity grid, which could enable a larger share of cheap renewable electricity generation capacity (Liu et al., 2024) or directly compensate EV drivers for modifying their charging behaviour (Baringa, 2022). Decisions cannot be made in isolation; they require an integrated strategy that considers the interactions between different technologies and sectors.

Another key challenge with marginal abatement costs is their short-term nature. They offer a snapshot in time of the relative costs, which can be useful to prioritise cost-efficient reductions in GHG in the near term, but achieving long-term net-zero emissions requires an alternative approach. For example, marginally improving gasoline cars or hybridisation can be cost-effective in the short run but will not fully decarbonise the transport sector. Instead, a more significant technological shift is needed to technologies that can use 100% renewable energy. The focus should not just be on minimising costs for incremental reductions but on transformative changes needed to eliminate all emissions (World Bank, 2023).

Climate transitions should ideally aim to minimise the total costs of decarbonisation to society, which requires estimating how technologies and costs will evolve over time and the associated uncertainties. Technologies such as solar PV and wind power were once deemed too expensive but are now among the cheapest energy sources due to early investments, economies of scale and learning effects.

However, some uncertainties can also be ruled out if they only change marginally over time or don’t change relatively to another pathway. For example, this can be the case due to physical limitations such as low energy conversion efficiencies that cannot be overcome, or other technologies that are likely to always remain expensive due to the lack of a sufficiently large market to achieve economies of scale. Learning effects and economies of scale have historically been better for technologies that are relatively standardised and can be produced in large numbers, such as batteries and solar panels (Wilson et al., 2020). This is already less the case for facilities to produce green hydrogen, which is an interlocking system of many complex technologies (Ramboll, 2023), and even more so for possible for large, bespoke, one-off projects, such as building nuclear power plants or retrofitting carbon capture equipment to power generation facilities.

Essential decarbonisation technologies with high initial MACs should be supported if they have the long-term potential to become cost-competitive and viable. Conversely, technologies, such as carbon-based e-fuels for road transport, which currently have high MACs should not be supported since their GHG emission savings per unit of energy are lower with respect to electrification, and their potential for cost reductions is limited (Ueckert et al. 2021).

Willingness to pay

Market actors will only adopt new technologies if they are economically competitive with conventional alternatives, or if consumers have a higher willingness to pay for the more expensive technology. However, the cost that different sectors are willing to pay for an energy resource will also determine which application will be prioritised. For example, an industrial sector that is willing to pay a high price for low-carbon electrolytic hydrogen – e.g. because of regulatory requirements to decarbonise and the cost impact on end-use prices is low – is likely to outcompete other sectors.

A sector's willingness to pay for new green technology is influenced by a range of factors, including taxation structures, regulatory requirements, the amount they can pass on in terms of additional costs downstream to consumers, whether they could continue to have access to regulated markets, the competitive environment and whether there are alternative, cheaper low-carbon technologies that could be used instead.

In sectors where multiple cost-effective alternative low-carbon technologies exist (e.g. road transport), the willingness to pay for more expensive energy resources, such as biofuels and e-fuels, is limited by the cost of cheaper competing solutions, such as direct electrification.

In sectors with limited cost-effective alternatives, the willingness to pay is influenced by various factors, including the effects of decarbonisation investment decisions on the value of existing assets and the impacts of policy-driven conditions on market access. For example, in the chemical industry, regulatory requirements that encourage reducing the carbon intensity of products that use low-carbon hydrogen as a feedstock (such as ammonia for fertilizer production) can lead to investments in low-carbon supplies, even at a high initial cost, without causing significant increases in product prices. This is because low-carbon hydrogen supplies, though initially limited, are essential for maintaining market access and allowing the continued use of large-scale, capital-intensive facilities without significantly increasing the production costs of final chemical products, such as fertilisers. The willingness to pay for low-carbon hydrogen is likely to decrease as the mandated share increases, indicating that without economies of scale, technological advancements and greater investments to expand low-cost low-carbon energy supplies, it is crucial to manage the risk of significant price hikes in end products or services reliant on these chemical products.

An effective strategy to achieve this is for regulatory carbon intensity requirements to target high-value final products or services that rely on hydrogen-intensive products as intermediate inputs. Examples include processed food (for fertilisers), transport vehicles (for steel), and petrochemical refining (e.g. plastics). Policy makers can influence market decisions on technologies by using regulation to shape the willingness to pay for low-carbon technology and by imposing financial penalties for non-compliance. In this context, policy actions can guide different supplies toward end use applications that are more or less likely to maintain long-term demand resilience. By focusing on cases with stronger resilience and lower risk for low-carbon hydrogen demand – due to the availability of lower-cost low-carbon alternatives – policy makers can help reduce the risk of asset stranding in low-carbon hydrogen supply capacity. Tools to influence willingness to pay include not only regulatory measures (e.g. mandates for a certain share of low-carbon hydrogen or its derivatives) but also economic instruments (e.g. tax rebates or auctions for access to public funds or other technology deployment support). Both approaches can be targeted at sectors where demand is likely to be more resilient, thereby reducing investment risks for prospective suppliers.

Creating demand for new energy resources is crucial to ramping up supply and ultimately lowering costs. This can be achieved by targeting sectors with the highest willingness to pay and using mandates to stimulate demand.

Beyond techno-economic considerations

One risk of prioritising energy resources technocratically based on existing demands and solely focussing on minimising costs is that considerations of fairness and equity may be omitted. The wealthiest 10% of the population produced 48% of global GHG emissions in 2021 (IEA, 2023f). The average North American produced eleven times more energy-related CO_2 emissions than the average African (IEA, 2023f). However, those most likely to face the costs of climate change live in regions which use comparatively little energy (International Monetary Fund, 2021; Taconet et al., 2020).

When considering “resource scarcity”, it is important not to forget that energy resources could be more plentiful if energy was used more equitably. The electricity and battery material demands needed to power a large electric SUV could be used to provide mobility to a greater number of people if they were used in electric two- or three-wheelers or buses (ITF, 2023a). Behavioural changes, such as modal shifts from individual transport to public transport and flights to trains, would also help to relieve pressure from scarce resources like biofuels.

Considerations of fairness and social equity need to be considered in the context of the overall system and a short-term view can distort conclusions. For example, some consider using e-fuels in road transport as a way to maintain existing industries producing combustion engines and thereby limit the effects on employment in the automotive sector. However, this view omits the fact that such vehicles would be more expensive to operate, placing economic burdens on a larger number of consumers and doing little to improve the long-term industrial prospects of a fundamentally costly and energy-inefficient technology. It would also do little to improve other externalities of internal combustion engines, such as air pollution. Promoting sustainable transport, both with modal shift to collective modes and adopting zero-emission vehicles has been shown to have additional co-benefits, such as health, particularly for marginalised communities (ITF, 2024b).

Adopting a merit order for the transport sector

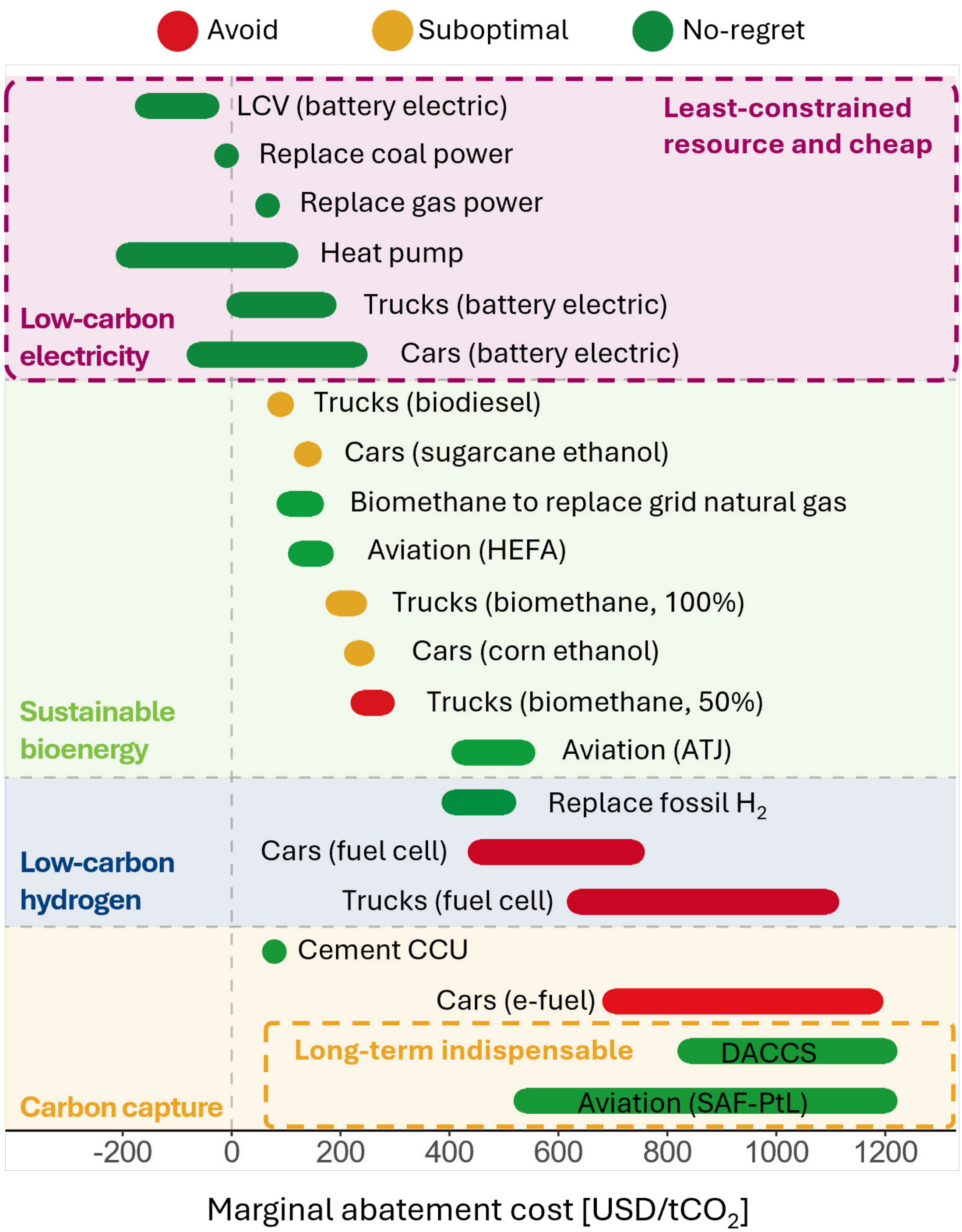
Several metrics were introduced earlier that should feed into prioritising the key resources across multiple sectors of the economy. Figure 8 combines these metrics for the transport sector and includes some selected examples from other sectors with significant GHG emissions, such as residential heating, cement production or the power sector.

Renewable electricity

Direct electrification applications lead in most individual metrics due to their high systemic efficiencies (high GHG savings per kWh) and low marginal abatement costs compared to equivalent fossil-fuelled technologies. Since electrification is also the technological solution with the highest potential to be environmentally and economically sustainable in the long term, it should therefore have the highest priority wherever the technology is available at a commercial scale. Exceptions are cases where batteries would need complex swapping systems to be economically attractive and not have an outsized scale (as in the case of shipping) or in cases where their weight penalty is also hindering energy efficiency (as in the case of larger aircraft and longer distance flights).

Within the transport sector, renewable electricity should be prioritised for the direct electrification of road and rail transport modes. For sectors of the economy for which electrification is a technological option, it is likely to be the most energy-efficient solution with the lowest MACs compared with other competing solutions. Long-distance heavy-duty vehicles have greater technological uncertainty than light vehicles, but electrification should remain the priority solution (ITF, 2023c).

Figure 8. A cross-sectoral merit order to allocate scarce energy resources across the economy



Note: See Annex A for methodology. This figure shows the merit order for the use of key resources and several low-carbon technologies to replace their fossil counterparts: road vehicles to replace fossil-fuelled vehicles; replace new-built coal and gas power with renewable power generation (wind & solar PV); heat pumps to replace residential heating. Fuel cell electric vehicle use hydrogen produced with renewable electricity. HEFA = Hydrotreated esters and fatty acids. ATJ = Alcohol-to-jet. CCU = Carbon Capture and Utilisation, DACCS = Direct air capture with carbon sequestration, SAF = Sustainable aviation fuel. PtL = Power-to-liquid. E-fuel and SAF-PtL technologies require H2 but are grouped into carbon capture technologies resources for the ease of reading.

Hydrogen

Hydrogen should be prioritised for sectors that already use it, such as the fertiliser and chemical industries. Renewable hydrogen energy resources are reliant on the availability of renewable electricity deployments and face additional challenges in being scaled up to meet the demands of a net-zero world. The willingness to pay for hydrogen is likely to be highest in sectors that already use it as a feedstock, as they are characterised by capital-intensive assets that will need to transition to low-carbon feedstocks or rely on carbon capture to align with net-zero requirements. These are sectors where a significant demand and infrastructure already exist and where increasing shares of green hydrogen can be blended in (IEA, 2023b). Other sectors where hydrogen is a priority are those in which few alternative technological solutions, such as electrification, can compete cost effectively while delivering significant GHG emission reductions. Developing regulations to mandate the use of green hydrogen in these sectors with relatively low marginal abatement costs can be a useful way to accelerate the deployment of hydrogen projects and kick-start economies of scale to bring down costs (Wilson et al., 2020).

In the future, when existing uses of hydrogen have driven a sizeable adoption, helped to mature the technology and brought down costs, then other more challenging segments, such as aviation and shipping, could be targeted. Pursuing a pathway for hydrogen to be used in sectors such as road transport, where the associated costs are higher and where electrification offers a cheaper alternative technological solution, would result in a more expensive and less effective way to scale up hydrogen use.

Bioenergy

Sustainable liquid biofuels should ideally be prioritised for the aviation and shipping sector over heavy-duty road freight since the latter can be decarbonised using electrification. Achieving this globally is challenging because fuel in the aviation and shipping sectors is not taxed. This makes the price difference between conventional fuels and low-carbon biofuels much larger than the difference between road diesel and road biofuels. Global (or regional) regulations, such as blending mandates with financial penalties for non-compliance and/or carbon pricing, are crucial to bridge this price gap and ensure a better allocation of bioenergy resources. Additionally, biofuel blending mandates in the road transport sector should be progressively phased out to avoid restricting feedstock availability for hard-to-abate modes.

Feedstocks already in use should be complemented by sustainably produced bioenergy. Reliance on food and feed crops will need to be reconsidered in light of competition with other demands and risks that rapid changes may have on food price increases (these can also have disproportionately negative effects on low-income households, globally). Policies should protect land with high carbon stocks (as not doing so would risk reversing GHG emission savings) and/or rich in biodiversity. They should also consider the relevance of habitat restoration to reverse historical trends leading to biodiversity loss and increase naturally occurring carbon storage, while also considering risks of progressive degradation of these ecosystem services due to climate change.

Biofuels should be prioritised over synthetic hydrocarbon fuels for decarbonising aviation since they are likely to provide a cheaper and more sustainable pathway in the short to medium term, provided they are produced with sustainable feedstocks and do not lead to indirect land use change.

However, prioritising ethanol for the aviation sector over the road sector also needs to be balanced with equity concerns and regional differences, since biofuels can help emerging economies to decarbonise and aviation demand is dominated by the relatively wealthy.

Biomethane is likely to be of highest priority in decarbonising existing uses of fossil gas, such as in high temperature applications, provided it can be cheaper than novel electric solutions that are being developed (FCA, 2024a). Biomethane is also particularly valuable in its ability to provide flexible power generation (IEA, 2023d). Biomethane is unlikely to be used in the aviation sector, which will favour liquid fuels. However, it may be a potential solution to decarbonise the shipping sector using LNG ships. Biomethane could play a complementary role to electrification in decarbonising the transport sector for regions with significant availability of supply and applications where natural gas is currently used. Any use of biomethane in the transport sector must avoid promoting or extending the use of fossil gas. Any newly built biofuel or biogas infrastructure for the transport sector must be limited to a minimal use of fossil fuel.

Biofuel and biogases may continue to play a role in the decarbonisation of the transport sector in emerging economies in cases where electrification proves challenging due to the associated high upfront purchase costs and requirements for flexible and developed electricity grids.

Synthetic fuels

Synthetic hydrocarbon e-fuels should not be prioritised for road and rail applications since there are cheaper, more energy-efficient alternative technologies available. The production of synthetic fuels is energy intensive, primarily due to the production of green hydrogen and the abated emissions per unit of electricity which are low in comparison to other sectors (see Figure 5). For these reasons synthetic carbon-based fuels are lower in priority than the direct electrification of end uses.

Synthetic fuels should, therefore, be reserved for hard-to-abate modes, such as long-distance aviation and shipping, which cannot be cost-effectively electrified as a complement to biofuels. Synthetic fuels may play an important role in the long term to decarbonise remaining applications, when the availability of cheaper sustainable biofuels is exhausted. Since synthetic fuels are energy inefficient, promoting their use in the short to medium term of the transition has risks because they could cannibalise renewable electricity and hydrogen resources that could be better used in other sectors where they may have higher GHG emissions savings.

In principle, mandating synthetic fuel use could help to stimulate demand for the energy resources needed to produce it. However, in the short to medium term this needs to lead to the deployment of additional capacities of renewable electricity generation and electrolysers rather than using resources from other sectors. In the long term, when renewable electricity, hydrogen and sustainable carbon feedstocks are no longer scarce and the fuels can be produced at a competitive price, their adoption should be actively stimulated.

However, commercial market adoption at a large scale still requires research and development as well as upscaling of advanced processes such as Fischer–Tropsch that can use secondary biomass feedstock (e.g. agriculture residues). One of the first production facilities of this type is expected to come into operation in 2027 (Topsoe, 2024). However, at least two facilities per EU member state would be required by 2035 (ICCT, 2024). Given low rates of FID for these types of facilities, efforts should focus on securing investments through long-term purchase agreements between airlines and fuel producers while assuring that highly ambitious targets for the deployment of renewable electricity targets will be met.

Towards the implementation of a merit order system

Government policies are needed to align market incentives with a merit order system

Policy support is crucial to provide long-term visibility on hydrogen applications and markets but should prioritise sectors where hydrogen is essential. The broader energy transition could be delayed if policy support is misdirected and hydrogen is promoted in sectors where better alternatives exist (e.g. heat pumps, electric vehicles). Policy solutions should include targeted guidance on sector eligibility for subsidies, possibly supplemented by mandates to lower policy costs. A transition from subsidies to market mechanisms is also needed, such as long-term carbon pricing which could reduce policy costs further.

Many countries have regulatory mandates that specify a proportion of biofuel that must be blended with conventional fuels, such as E10 in the European Union (90% gasoline and 10% bioethanol). Biofuel blending mandates in road transport have been useful to build up refinery capacities and a market for biofuels which would not exist without policy support. However, moving forward, such refining and production capabilities will need to continue to grow and be tailored more towards the production of fuels for non-road-based applications. Using biofuel feedstocks in the road transport sector risks limiting availability for the aviation and shipping sectors in the long term.

One challenge with shifting feedstock use from the road to aviation sector is creating the correct price signals. Companies currently have a greater motivation to produce biofuels for the road transport sector than for the aviation sector due to two challenges: technological and regulatory. Producing biogenic fuels for the aviation sector can cost more than fuels using the same feedstocks for the road-based sector. For example, using ethanol for road vehicles is less expensive than converting the ethanol using an alcohol-to-jet pathway to make kerosene. Similarly, using hydrotreated vegetable oil (HVO) in trucks costs less than using feedstocks to make HEFA jet fuels (WEF, 2020). These technological differences make pricing the production of biofuels for hard-to-abate sectors difficult. Therefore, regulatory changes are needed to counteract these technological barriers since the aviation and shipping sectors are unable to be cost effectively electrified in the same way as the road transport sector. Policies to internalise environmental damages and bridge the price gap between conventional fossil fuels and low-carbon alternatives include adopting fuel taxes and carbon prices for fossil-based shipping and aviation fuels (currently subject to much lower taxation than road fuels) along with sector-specific mandates having strong non-compliance penalties, as well as economic incentives, which can be financed by carbon taxes.

Regulatory instruments in place in road transport need to move in the opposite direction, freeing up supplies for sectors that otherwise risk struggling to secure sufficient low-carbon fuel supplies, while having limited alternatives. Policies targeting sectors in isolation risk creating misaligned incentives to use scarce energy resources in sub-optimal applications, although they are necessary in cases where the current framework provides misleading signals to the markets.

Accounting for regional differences in merit orders

Implementing a global, universal merit order system faces multiple challenges. A primary issue is that a regional optimum may not align with the global optimum, leading to inefficiencies in resource allocation on a global scale. For example, at a global level, biofuels are likely better suited to decarbonise hard-to-abate sectors. However, the prices and availability of energy resources differ between countries. A region with cheap local supplies of biofuels may choose to use them locally in a sector (such as road transport), which at a global level could well be considered sub-optimal.

There are several additional reasons why local merit order priorities may not align with a global optimal allocation. A country with a dependency on imported fuels might want to reduce the impact this has on the trade balance by opting for locally available resources such as biofuels. Similarly, some regions may place an additional premium on ensuring energy security by diversifying energy demands and promoting energy domestic resources, even though they may yield greater emissions savings if used in other regions. It is worth noting that promoting electrification can help to improve energy security since it is energy efficient (reducing the overall demand for energy imports) and can be produced from a variety of technologies and resources, offering resilience through diversification.

A question of equity also exists: why should an emerging economy with abundant resources sell them internationally to a developed economy and use another, potentially more expensive technology locally to satisfy its needs? This is maybe most pronounced for biofuels in the aviation sector, since the wealthiest 25% of the global population are responsible for more than 90% of the aviation-related activity and its respective emissions (ITF, 2024a), while a part of the global population has no basic access to mobility services. Higher export prices can help bridge this limitation, as long as they allow for offsetting additional costs that would be incurred locally from choosing an alternative technology better aligned with the global optimum. A fundamental premise would be robust redistribution tools and governance structures to enable local populations to benefit from a country's natural endowment. A similar question arises with regard to the local workforce, which varies by region and can be particularly pronounced, if an economy is strongly dependent on the agricultural or fossil fuel sector. However, this green transition also offers huge opportunities for the labour force, where job losses in the fossil fuel sector could likely be compensated for by job additions in the clean technology sector (Larson et al., 2022).

Some decarbonisation technology pathways have a higher share of capital investment (CAPEX) or operational costs (OPEX) in the total cost. For example, electrification requires far more initial CAPEX in relatively expensive vehicles but has much lower OPEX. While CAPEX-heavy solutions can work in countries with access to low financing costs, countries, especially in emerging economies, might opt for solutions that have the lowest upfront cost (e.g. biofuels). To better align regional approaches towards global optimal allocations it is essential to improve access to financing to allow for the most efficient technological solutions.

Another potential reason for a misaligned prioritisation of resources between regions is if carbon pricing is unevenly applied across different jurisdictions. This can create a competitive disadvantage in terms of energy prices. Higher carbon prices can be useful for countries to gain a first-mover advantage in clean technology manufacturing and/or adoption. However, in the long term, it can lead to structural challenges in economic competitiveness.

Since there is merit in the correction of sector-specific market failures induced by differentiated taxation (as in the case of road fuels compared to aviation and shipping fuels), there can also be value in adopting corrective, differentiated carbon prices in the same sectors. In this context, policies intended to correct disparities in carbon pricing, such as the EU's Carbon Border Adjustment Mechanism, may need to include sector-specific adjustments to account for modifications in the current taxation structure to provide market signals that are better aligned with the merit order enabling a global optimum in terms of cost minimisation. This is especially relevant in the absence of a global agreement capable of providing corrective signals internationally. This is also hard to implement, as there could be many divergent views regarding this same global optimum, thus opening opportunities for arbitrary and discretional choices attempting to alter global trade patterns.

Using a global merit order for the allocation of scarce energy resources is useful as a guide in the development of energy policies, since some prioritisation will be inevitable to reach ambitious climate goals. However, the above examples highlight some of the real-world complexities of its implementation that will need to be overcome. A global merit order should, therefore, be considered an aspirational target.

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Annex A. Methodology

Supply and demand for hydrogen

The hydrogen demand for 2030 is based on transport demand and provides a comparison to current supplies. It uses green hydrogen production project status' for 2030, based on announcements as of 2024. It should be noted that the demand for hydrogen is not a forecast, but purely for illustrative purposes. Transport demand uses the High Ambition scenario from ITF's own transport demand modelling, which will be published in the ITF Transport Outlook 2025 (ITF, forthcoming). The hydrogen demand assumes energy efficiencies from different vehicle types and powertrains taken from Table 10 in ITF (2021a). Aviation is assumed to use synthetic kerosene. This is converted into hydrogen demand assuming 0.52 kg of H_2 is needed per kg of synthetic kerosene (FCA, 2024b). Shipping is assumed to use ammonia which is converted into hydrogen demand using stoichiometric ratios and assuming a Haber-Bosch efficiency of 70% meaning 1.63 MJ of hydrogen is needed to produce 1MJ of ammonia.

The status of green hydrogen projects is taken from Odenweller and Ueckerdt (2024). Supply of existing fossil hydrogen is from IEA (2024b). The hydrogen supply (EJ) is inferred from electrolyser capacity (GW) by assuming a capacity factor of 3750 hours/year, based on the range of 3250-4250 hours/yr taken from Zeyen, Riepin and Brown (2024).

Bioenergy availability

Figure 3 includes estimated energy demand needed for the transport sector to decarbonise by fully utilising biofuels. The energy demands are estimated using transport activity projections from the High Ambition scenario from ITF's Transport Outlook 2025 (ITF, forthcoming). The hypothetical energy demand for aviation is estimated assuming all aircraft using SAFs. All other modes are assumed to continue using internal combustion engine technologies.

Table A1 contains the values used in this report for the total potential supply of sustainable bioenergy in 2050, and Table A2 shows the shares of solid, liquid and gaseous form of the bioenergy, respectively.

Figure 3 also includes estimates for today's energy demand from industrial process heat, which is estimated from (Orennia, 2024). Only energy-related emissions from process heat above 1000°C are considered from the three biggest emitting sectors in industry (cement, iron & steel and chemicals), which today is largely provided by the combustion of fossil fuels, such as coal or natural gas. The share between process-related emissions (not considered here) and energy-related emissions are sourced from (FCA, 2022), (Frauenhofer ISI, 2024), (EEA, 2024) and (Resource Efficiency Collective, 2014). Considering elevated medium temperature range (500–1000°C) and medium temperature range (100–500°C), which is mostly also provided by the combustion of fossil fuels, the energy demand related to process heat would increase to 72.6 EJ and 95.4 EJ, respectively.

Table A1. Literature values for the total availability of sustainable bioenergy in 2050.

Lower bound [EJ]	Upper bound [EJ]	Mean (2050) [EJ]	Reference	Note
NA	NA	130	IRENA (2023)	
NA	NA	102	IEA (2023c)	
70	100	85	MIT Global Change (2024)	
118	312	215	IPCC (2019)	
162	267	214.5	IIASA (2012)	
10	245	127.5	Creutzig et al. (2015)	Meta study reviewing >74 studies
60	120	90	Searle and Malins (2015)	
64	313	188.5	Errera et al. (2023)	

Note: All values are in exajoules (EJ).

Table A2. Share of solid/liquid/gaseous bioenergy.

Mean supply (2050) [EJ]	Solid	Liquid	Gaseous	Reference
130	67%	21%	12%	IRENA (2023)
102	74%	11%	15%	IEA (2023a)

Note: All values are in exajoules (EJ).

Direct air capture: Air processing requirements

The molar mass of air is approximately 29 g/mol, resulting from a weighted average of its constituents: 28 g/mol for N_2 (78% in volume), 32 g/mol for O_2 (21% in volume), 40 g/mol for argon (around 1% in volume), and 0.04% (410 ppm) of CO_2, which has a molar mass of 44 g/mol. There is only 0.018 gCO_2/mol of air.

Since there is a need for 3.1 kg CO_2/kg of hydrocarbon and the energy content of a diesel-like hydrocarbon is 43.3 MJ/kg, it is necessary to process 115 kg of air/MJ of diesel-like fuel (assuming no loss). Considering 36 MJ/L for diesel-like fuel leads to and 4 123 kg of air/L of fuel. With 1.29 kg of air/m^3 at standard ambient pressure and temperature, this corresponds to 3 190 m^3 of air/L of fuel.

Air masses and volumes increase accounting for real-world efficiencies (i.e. ratios between CO_2 captured and CO_2 present in the air flow) of the contactor. With an air flow speed of 5.4 km/h (1.5 m/s) and a contactor efficiency of 75% (used by NAP [2019], and more optimistic than the 2 m/s and 50% values indicated by (Mazzotti et. al, 2013) as typical), a fan with a diameter of one metre (0.78 m^2 of frontal area) would need to operate for one hour to process the amount of air at ambient pressure containing the carbon needed to produce one litre of fuel or capable to offset its direct CO_2 emissions from combustion.

GHG emissions savings per unit of renewable electricity

The ranges shown in Figure 5 in the report are estimated by calculating the amount of electricity that would be required for each process and the carbon emissions saving that could be obtained by substituting renewable energy for the conventional fossil fuel technology. To account for uncertainties in current and future energy efficiencies and carbon intensities an upper and lower bound for key variables are used. Renewable electricity (including embodied emissions) are assumed to range between 30 gCO_2/kWh and 100 gCO_2/kWh. This range is applied to all technologies.

Coal and gas power currently have carbon intensities of 1 000 gCO_2/kWh and 600gCO_2/kWh respectively. Substituting them with renewable electricity could save between 0.9–0.97 kg CO_2/kWh of renewable electricity and 0.5–0.57 kg CO_2/kWh of renewable electricity respectively.

A gas boiler is between 87–96% efficient for domestic heat. Substituting it with a heat pump which has an efficiency between 250–400% efficient could save between 0.4–0.9 kg CO_2/kWh of renewable electricity.

Conventional fossil hydrogen production in refineries and fertiliser production produces between 10–17 $kgCO_2/kgH_2$ (Parkinson et al. 2019). Substituting this with hydrogen produced in an electrolyser (which is between 55–70% efficient) could save between 0.04–0.27 kg CO_2/kWh of renewable electricity.

A medium-sized gasoline car produces between 120–130 g CO_2/km. Substituting this with an electric car, which uses between 14–17 kWh/100km, could save approximately 0.6–0.9 kg CO_2/kWh of renewable electricity.

A heavy freight truck produces between 850–960 g CO_2/km. Substituting this with an electric truck, which uses between 1.4–1.7 kWh/km, could save approximately 0.43–0.67 kg CO_2/kWh of renewable electricity. A hydrogen truck using electrolytic hydrogen, which consumes between 8–9 kg H_2/100km, could save between 0.04–0.18 kg CO_2/kWh of renewable electricity.

Capturing CO_2 from an industrial point source such as a cement plant requires approximately 1.1 kWh/$kgCO_2$ captured. However, this CO_2 then has to be compressed, transported and injected into a storage facility which can require between 95–160 kWh/tonne of CO_2. The overall savings are, therefore, 0.69–0.8 kg CO_2/kWh of renewable electricity used for the process. This assumes that all the captured CO_2 is stored permanently. If the CO_2 is utilised, for example to make an e-fuel, then the credit for the carbon saved is likely to be split between the industrial point source and the user of the CO_2 (e.g. the e-fuel producer). This means the carbon savings should be halved compared with CCS. For DACS, the calculations are the same as industrial point source CCS but the energy intensity of CO_2 capture is approximately 2 kWh/$kgCO_2$. The overall savings for DACS are therefore 0.36–0.44 kg CO_2/kWh of renewable electricity used for the process.

Burning kerosene produces approximately 2.4 $kgCO_2$/litre. Substituting this with an e-fuel would require approximately 0.52 kgH_2 and 3.4 $kgCO_2$ per kilogramme of e-kerosene assuming a 90% efficient yield (FCA, 2024). Assuming the above ranges of uncertainty for hydrogen production and CO_2 capture, an e-fuel produced with DAC could save up to 0.05 kg CO_2/kWh of renewable electricity. However, there are many cases in which there would be no CO_2 savings relative to fossil kerosene if the carbon intensity of the electricity used is above roughly 50 g CO_2/kWh. An e-fuel produced with CO_2 captured from an industrial point source would likely have to share the carbon credit (e.g. a cement plant and an e-fuel producer could not both claim 100% credit for the captured CO_2). Assuming an equal split of the carbon credit the e-fuel could save up to 0.04 kg CO_2/kWh of renewable electricity.

Marginal abatement costs

The estimates of marginal abatement costs for different low-carbon technologies shown in Figure 6 of the report are calculated by dividing the difference in total cost (of ownership) between two technologies by the difference of their respective lifecycle emissions.

The total cost of ownership of each vehicle type/powertrain combination is calculated by combining vehicle purchase costs, operational costs, maintenance, insurance and financing costs. The annual mileage of cars, LCVs and trucks are assumed to be 12 000 km, 25 000 km and 125 000 km respectively. Assumed vehicle lifetimes are 16 years, 16 years and 7 years respectively. The vehicle fuel efficiencies can be found in the appendix of (ITF, 2021a). For the purpose of this analysis, gasoline and diesel are assumed to cost USD 1.0/litre, electricity USD 0.25/kWh, biogasoline USD 1.3/litre of gasoline equivalent, biodiesel USD 1.24/litre of gasoline equivalent, green hydrogen USD 15/kg today (at the pump with production costs of USD 8/kg) and USD 11/kg in 2035 (production cost USD 6/kg) (IEA, 2024b). Insurance costs are assumed to be USD 400 per year for ICEV medium cars and USD 600 per year for BEVs and FCEVs (IEA, 2024). Maintenance costs per year are estimated at USD 250, USD 100 and USD 180 per year for ICEV, BEV and FCEV cars respectively. Vehicle purchase prices for ICEV, BEV and FCEV are estimated at USD 27 000, USD 37 000 and USD 43 700 for medium cars, USD 34 500, USD 51 500, USD 56 000 for LCVs (Routelogic, 2024) and USD 165 000, USD 275 000 and USD 285 000 for heavy trucks, respectively. Lifetime financing costs are assumed to be 7% of vehicle purchase prices.

The total cost of ownership (TCO) for medium cars in 2025 is estimated at USD 0.27/km for gasoline ICEVs, USD 0.30/km for BEVs, and USD 0.49/km for FCEVs; USD 0.29/km for bioethanol ICEVs. The TCO in 2035 is estimated at USD 0.27/km for gasoline ICEVs, USD 0.26/km for BEVs, and USD 0.40/km for FCEVs; USD 0.29/km for bioethanol ICEVs.

The TCO for LCVs in 2025 is estimated at USD 0.23/km for diesel ICEVs, USD 0.22/km for BEVs and USD 0.49/km for FCEVs. The TCO for LCVs in 2035 is estimated at USD 0.22/km for diesel ICEVs, USD 0.19/km for BEVs and USD 0.39/km for FCEVs.

The TCO for heavy trucks in 2025 is estimated at USD 0.60/km for diesel ICEVs, USD 0.74/km for BEVs and USD 1.64/km for FCEVs. The TCO for heavy trucks in 2035 is estimated at USD 0.58/km for diesel ICEVs, USD 0.60/km for BEVs and USD 1.23/km for FCEVs.

The lifecycle emissions estimates build upon the ITF vehicle lifecycle model developed as part of previous ITF projects (ITF, 2021a, 2020). Estimates include vehicle production emissions (including electric vehicle batteries), well-to-tank emissions and tank-to-wheel emissions. Each vehicle type and technology is compared with a comparable fossil fuel vehicle it would substitute for. The lifecycle emissions for BEVs is calculated assuming the global average carbon intensity of electricity generation and how it is expected to change over time according to IEA forecasts. Lifecycle emissions of BEVs would be even lower using the average carbon intensity of the electricity grid in Europe or North America.

The carbon intensity of biodiesel is assumed to be 37 gCO_2/MJ (Prussi et al., 2020), biomethane for grid injection 11.7 gCO_2/MJ, when converted to LNG for transport use it carbon intensity rises to 13.1 gCO_2/MJ (Noussan et al., 2024). The carbon intensity of corn ethanol and sugarcane ethanol are estimated at 57.5 gCO2/MJ (52 gCO_2/MJ + 5.5 gCO_2/MJ of indirect land use change (Cai et al., 2022) and 36 gCO_2/MJ (26 gCO_2/MJ direct (Cai et al., 2022) + 10 gCO2/MJ indirect (ICAO, 2024)), respectively. LNG engines in trucks are assumed to have consume 4% more energy than comparable diesel engines due to ower thermal efficiencies (ICCT, 2020). The MAC for biomethane is estimated using a carbon intensity based on a representative mix of different feedstock pathways. There are some biomethane pathways with negative emissions but these are limited in availability and are likely to only account for a minor share in most biomethane blends (Cai et al., 2022).

The carbon intensity of e-fuels is estimated assuming they are produced with 100% renewable electricity (with a corresponding carbon intensity of 35 gCO_2/kWh) in an optimised heat integrated process that requires 2.2 units of energy for every unit of gasoline produced sourced from (Concawe, 2022). This leads to a carbon intensity of e-gasoline of 0.71 $kgCO_2$/L. The cost of e-gasoline is estimated from (Concawe, 2022) assuming EUR 101/GJ today and EUR 71.3/GJ in a decade (to be roughly comparable to the hydrogen costs from (IEA, 2024b)).

Costs for sustainable aviation fuels (HEFA (used cooking oil), power-to-liquid (water electrolysis and reverse water-gas shift), alcohol-to-jet) are sourced from WEF (WEF, 2020) for 2025 and 2035. The well-to-wake carbon emission intensity for SAFs is sourced from (ICCT, 2021), (Liu, 2023) for Brazilian sugarcane, which is the most cost-efficient pathway, PtL with carbon intensities of the electricity mix for renewables (45 gCO_2e/kWh and 25 gCO_2e/kWh) taking into account additionally criteria (ITF, 2023).

The MACs for replacing coal and gas power (combined cycle) with renewables uses levelized costs of electricity (LCOE) from (Lazard, 2024) as of June 2024. The LCOE for renewables are averaged between solar PV and wind power onshore generation and include costs for storage for both technologies with an average LCOE of USD 112/MWh. The MACs for heat pumps vary by the heating technology they are replacing. The ranges refer to replacement of an oil-fired boiler and direct heating (Patteeuw, 2015).

The MACs for green hydrogen replacing hydrogen made with natural gas uses the cost assessment and emission intensities for natural gas steam reforming and average between solar PV and onshore wind from IEA's Global Hydrogen Review (IEA, 2024b). The carbon intensity of fossil hydrogen is assumed to be 11 $kgCO_2/kgH_2$ while renewable hydrogen is assumed to be 1.55 $kgCO_2/kgH_2$. Fossil hydrogen production currently ranges in price between USD 0.8–5.7/kgH_2 and is expected to reduce to USD 0.5–3.8/kgH_2 in the future. Renewable hydrogen production currently ranges in price between USD 3.9–12/kgH_2 and is expected to reduce to USD 2.2–9.7/kgH_2 in the future. Distribution and refuelling costs for transport purposes are optimistically estimated at USD 2.4/kgH_2 from (Concawe, 2022), note this is considerably lower than estimated by Shafiee and Schrag (2024), which estimates distribution and fueling costs at around USD 10/kgH_2.

The MACs for biomethane to replace natural gas in the grid uses the costs for the least expensive biomethane to replace 10% of the natural gas demand from IEA's Outlook for biogas and biomethane (IEA, 2020b), averaged by region. The carbon intensity of biomethane is assumed to be 11.7 gCO_2/MJ for grid-injected biomethane and 13.1 gCO_2/MJ for LNG biomethane for use in road transport (Noussan et al. 2024). The cost of transport fuels is sourced from current retail prices for fossil fuels from the Alternative Fuels Data Centre (US Department of Energy, 2024) and retail prices in Italy (Rattix, 2024).

The MACs for direct air capture (DAC) is sourced from the IEA (IEA, 2023i) and cement production with CCU from (Strunge, 2021) for large production plants with >40 kt/year and emission shares from (FCA, 2022).

Annex B. Roundtable participants

Henk STIPDONK (Chair), KiM

Alexis ROCA, Exxon

Anders HOVE, Oxford Institute of Energy Studies (OIES)

Andreas SCHÄFER, UCL

Andreas KOPF, ITF

Angelique BOURON, Total Energies

Annika BERLIN, UNEP

Doris EDEM AGBEVIVI, Energy Commission Ghana

Falko UECKERDT, PIK

Francisco LLAVERON, Iberdrola

Greg MARDSEN, University of Leeds

Jane O'MALLEY, ICCT

Jinlei FENG, IRENA

John PRITCHARD, ITF

Ken TRAN PHONG, Climate Champions

Linda SCHMIDT, US Grains Council

Louis-Marie MALBEC, IFPEN

Matteo CRAGLIA, ITF

Paul KISHIMOTO, IIASA

Philippe CRIST, ITF

Pierpaolo CAZZOLA, UC Davis

Soichiro MINAMI, TRC

Sonia YEH, Chalmers

Vincent ERARD, IRU

Vir CHACHRA, ITF

The following participants attended by videoconference:

Lucie ANDERTON, UIC

Alissa COTTON, Shell

Andrea PAPU CARRONE, ITF

Antal BÓDI, TRC

David, DANIELS, TRC

Elena TALALASOVA, Global Maritime Forum

Eric DIMNET, TRC

Gabriele GRIMM, TRC

Gustavo RINALDI, TRC

Jacopo TATTINI, European Commission

James PARDY, TRC

Joisa CAMPANHER DUTRA SARAIVA, FGV/CERI

Julien FEUGIER, Airbus

Laurent DEMILIE, TRC

Luke SWEENEY, TRC

Madeleine MITSCHLER, Aramco

Manuel von METTENHEIM, European Commission

Mohamed ALI SAAFI, Aramco

Noriko OKUBO, TRC

Olivia WESSENDORFF, ITF

Omar ALHARBI, Aramco

Orla McCARTHY, ITF

Patrik HLAVATY, TRC

Philipp STREEK, DZSF

Philippe STEFANOS, UIC

Rose JONES, TRC

Sara HYLTON, TRC

Sebastian HIRSZ, BP

Sergey PALTSEV, MIT

Steffan BAKKER, TRC

Thomas Edward YU, University of Tennessee

William McMYN, BP

Yves BERTEAU, TRC

Josephine MACHARIA, ITF

Participants provided their affiliations at the time of their participation in the Roundtable meeting.

Endnotes

1. Levelised costs of electricity for nuclear in H_1 of 2023 were USD 225 per MWh, natural gas with CCS USD 128 per MWh and solar PV and onshore wind USD 44 per MWh and USD 42 per MWh, respectively.

2. This neglects to take into account that that these projects likely receive other non-Hydrogen Bank funding. Projects starting before 2028 are also exempted from the strict additionality criteria. These projects also price in revenues from allowances for green hydrogen starting in 2025, when H2 production is included in the European emissions trading system (ETS), which is estimated with EUR 0.7 per kg of H2 at current market prices (FSR, 2024). However, despite these additional cost reductions, the large majority of the surcharges ("green premium") are expected to be paid by the customer.

3. Unless the CO2 is captured at the tailpipe after the second utilisation and recycled further – something that could lead to greater savings. While this is not viable in aviation, this could be technically feasible and is being trialled on demonstrator ships but will face significant economic challenges.

4. Limitations in life-cycle carbon abatement on the one hand, and opportunities to accelerate the production of synthetic fuels thanks to lower cost sourcing of concentrated carbon on the other, are what justifies the choice to enable non-biogenic concentrated carbon sources as a way to produce synthetic fuels, while also limiting their viability as a suitable low-carbon option up to the year 2041 (European Commission, 2023).

5. DAC systems concentrate CO2 from the atmosphere into a form more easily stored or used. They do not, by themselves, store, dispose of, or convert it into any other form. Doing so requires complementary technologies (sequestration of CO2 in geological formations or chemical synthesis into solid products or different fuel types, combining the carbon contained in the CO2 with hydrogen). When DAC is coupled with underground storage of CO2, reservoirs are properly selected, carefully regulated, and sealed when full, they can effectively remove CO2 from the atmosphere permanently (Baker at al. 2020). Using the carbon to make carbon-containing products opens opportunities for revenue from the sale of those products to help offset the expense of DAC, which is important in the absence of a carbon pricing mechanism. However, doing so also returns that carbon to the atmosphere. If the carbon is used to make a solid product, then the carbon remains out of the atmosphere for as long as the carbon remains solid.

6. In this case, the linkage between DAC and the other activity can be physical, where the DAC equipment is integrated into the linked activity (e.g. DAC that utilises waste heat from an industrial process to reduce its energy demand). It can also be contractual, where negative emissions generated by DAC-CCS are transferred by contract to the linked activity, possibly with a carbon market as an intermediary.

7. To visualise this, 3 000 m^3 is roughly the volume of a rectangular box with a base area the size of a basketball court and 7 m high.

8. These fuels are then combusted, and while the embodied carbon returns to the atmosphere, it has little net long-term warming effect because the carbon was removed from the atmosphere recently (in climactic timescales).

9. The use of concentrated CO2 streams for recycled carbon fuels rather than DAC for fuel synthesis is less energy intensive than DAC for e-fuel processes, as the process of concentrating CO2 requires greater energy inputs if the CO2 has lower concentrations. The capacity of recycled carbon fuels to deliver decarbonised fuels is inherently limited though, unless the CO2 is part of a closed loop. This requires CO2 emissions from the combustion of the recycled carbon fuels to be recaptured, permanently stored or continuously re-used afterwards. Onboard CO2 storage is not viable in most vehicles, including aviation. It is however being considered for shipping applications (MMMCZCS, 2022).

10. Note that (Concawe, 2023) use values of 5.8 MJ/kgCO2 for primary heat and 1.4 MJ/kgCO2 for primary electricity, for DAC, in their e-fuel production assessment.

11. Should heat generated by electricity not be from low-carbon primary resources, emissions would quickly grow, due to low energy efficiency. Energy requirements would also grow, due to additional conversion losses.

12. The impact of the infrastructure depends on its use rate. Impacts are small for infrastructure deployed with significant rates of use, while they grow with under-utilised assets. This is also a risk in aviation and shipping, given the complexity and the costs of liquid hydrogen handling and its low volumetric energy density.

13. Primary heat requirements are lower for e-fuels than for DACCS due to the possibility of recovering waste heat from some of the fuel synthesis processes (Concawe, 2023). Primary electricity requirements are higher for DAC-based e-fuels due to the need to compensate this amount with greater amounts of hydrogen, per unit of energy delivered in the fuel, in line with the second law of thermodynamics.

14. The shares of thermal generation in global electricity production are still sizable, even if there are encouraging signs from the dynamic growth of renewable energy production (EMBER, 2023). Electricity production zones with high or very high shares of low-carbon electricity in the mix, not subject to the opportunity to displace thermal generation (and also limited in terms of capacity to export electricity to other zones), have the best conditions to pursue e-fuel/RFNBO production, from a systemic GHG emission saving perspective.

15. Natural gas for heat and to co-capture the CO2 produced during combustion could also be an option (IEA, 2023h), as long as CO2 capture and storage is highly effective. However, it would only be viable in a context where the gas would be subject to excess production and low-cost availability (this may be possible in a context needing to reduce methane emissions from oil and gas extraction)

16. For example, from geothermal or solar resources (eventually stored in water) to be recovered with heat pumps; potentially also natural gas with carbon capture (IEA, 2023h) in the unlikely event of very low cost and large-scale availability.

International Transport Forum

Managing Competing Sectoral Demands for Energy Resources
Transitioning to Sustainable Transport

Decarbonising the transport sector will increase demand for new energy resources, such as renewable electricity, low-carbon hydrogen, biogenic resources, and capturing CO_2. To meet climate goals and the associated demand for these resources, renewable energy supply needs to be scaled up at an unprecedented speed. Potential supply bottlenecks risk placing the transport sector in direct competition with other sectors of the economy, such as buildings and industry, or even between different modes within the transport sector.

To help manage scarcity and guide markets to better prioritise and allocate limited energy resources, governments should develop regulations following a cross-sectoral ”merit order”. The report supports governments in their long-term energy system planning to decarbonise the transport sector in tandem with the rest of the economy. It also explores supply bottlenecks and approaches to facilitate international co-operation, where appropriate.

International Transport Forum
2 rue André Pascal
F-75775 Paris Cedex 16
+33 (0)1 73 31 25 00
contact@itf-oecd.org
www.itf-oecd.org

OECD

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