circular carbon economy

07

Cross-cutting: Hydrogen.

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Table of contents

Table of contents

Figures

Tables

Boxes

Abbreviations

ATR	autothermal reforming
BEV	battery electric vehicle
BF-BOF	blast furnace-basic oxygen furnace
CAPEX	capital expenditure
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CG	coal gasification
CI	carbon intensity
CO	carbon monoxide
COP	coefficient of performance
CO_2	carbon dioxide
DAC	direct air capture

DRI	direct reduction of iron
DRI-EAF	direct reduction of iron-electric arc furnace
EOR	enhanced oil recovery
FCEV	fuel cell electric vehicle
GFEI	Global Fuel Economy Initiative
GHG	greenhouse gas
G20	Group of Twenty
H_2	hydrogen
ICE	internal combustion engine
IEA	International Energy Agency
IMO	International Maritime Organization
KAPSARC	King Abdullah Petroleum Studies and Research Center
LCOH	levelised cost of hydrogen
LH_2	liquid hydrogen
LOHC	liquid organic hydrogen carriers
LT	long term
MEPC	Marine Environment Protection Committee
MT	medium term
NG	natural gas
NH_3	ammonia
NO_x	nitrogen oxides
N_2O	nitrous oxide
OPEX	operating expenditure
PEM	polymer electrolyte membrane
POx	partial oxidation
R&D	research and development
RD&D	research, development and demonstration
SMR	steam methane reforming
TTW	tank-to-wheel
w	with
w/o	without
WTT	well-to-tank
WTW	well-to-wheel

Units of measure

bbl	barrel
bcm	billion cubic metres
g	gramme
GJ	gigajoule
Gt	gigatonne
GW	gigawatt
kg	kilogramme
kW	kilowatt
kW_e	kilowatt electrical
kWh	kilowatt-hour
MBtu	million British thermal units
Mt	megatonne
MWh	megawatt-hour
t	tonne
TWh	terawatt-hour
yr	year

Executive Summary

Hydrogen is enjoying unprecedented momentum across the world. This is raising expectations that it may finally meet its longstanding promise of making a substantial contribution to a lower-carbon energy future, as envisaged in many countries. Tremendous interest is growing among governments, industry and other stakeholders, who consider hydrogen to be a fundamental piece of a clean, secure and affordable energy system.

At their Osaka Summit in 2019, G20 leaders emphasised hydrogen as one of the critical technologies to enable clean energy transitions. The IEA prepared a report for the summit, "The Future of Hydrogen" (IEA, 2019a), a detailed analysis of the current state of hydrogen technologies, their potential to contribute to the transformation of energy systems across the world and the challenges to be overcome for their widespread adoption. Building on the findings from that work, and at the invitation of the King Abdullah Petroleum Studies and Research Centre (KAPSARC), in this study the IEA addresses the cross-cutting role of hydrogen within the circular carbon economy framework of the G20 Presidency of the Kingdom of Saudi Arabia in 2020.

Around 75 Mt of pure hydrogen and 45 Mt of hydrogen mixed with other gases are currently consumed every year, mainly in oil refining, the chemical sector and iron and steel production. These demands have grown consistently during recent decades and are likely to continue doing so, boosted by both traditional hydrogen consumers and new applications where the use of hydrogen to replace fossil fuels is rapidly gaining interest. These include transport, industry, buildings and the power sector.

However, the current economic crisis resulting from the Covid-19 outbreak is putting these prospects at risk. The sectors that account for the vast majority of current hydrogen demand have been seriously affected by this crisis. Hydrogen demand for oil refining is currently expected to drop by around 7% in 2020 compared with 2019. Similarly, many projects developing clean hydrogen production or due to demonstrate end-use applications, and which are currently under construction or in planning, may be delayed or even cancelled. The slowdown in economic activity resulting from lockdowns and social distancing, the disruption of supply chains and the lower capital expenditure of companies forced to prioritise other business areas could put at risk these and other future developments.

But government action can be decisive in ensuring that hydrogen does not lose momentum – it can even accelerate the development and deployment of key enabling technologies, such as carbon capture and storage and electrolysers for cleaner hydrogen production, or fuel cell vehicles that use hydrogen for transport.

Practically all hydrogen production is currently based on natural gas and coal, and is associated with more than 800 Mt of CO_2 emissions every year. For hydrogen to reach its potential as a clean fuel, its production will need to be increasingly based on low-carbon routes. Low-carbon hydrogen production is still costly when compared with production from natural gas and coal. This cost gap can be reduced significantly by scaling up low-carbon production, and by the adoption of policies that assign a value to their potential to reduce carbon emissions.

Cost reductions will be needed across the other parts of the supply chain as well, including hydrogen transport, delivery and end use. Several areas provide room for improvement. Examples include: more efficient and cheaper transport; optimising the utilisation of available infrastructure; developing new infrastructure for the delivery of hydrogen to end users; and increased demonstration and/or scale up manufacturing of end-use technologies.

The carbon reduction potential of hydrogen depends on the extent to which low-carbon hydrogen production is deployed and the efficiency of its end-use applications. Low-carbon hydrogen has the potential to contribute to the decrease in carbon emissions of numerous applications such as transport, chemical production, iron and steel production, buildings and industrial heating, and power generation. Conversely, using hydrogen produced from carbon-intensive pathways can lead to higher CO_2 emissions compared with other low-carbon alternatives.

Adopting a new clean fuel like low-carbon hydrogen is a challenging endeavour that has to overcome significant barriers beyond economics. The need for hydrogen infrastructure is a bottleneck preventing widespread adoption. It can be overcome by using existing infrastructure that is compatible with hydrogen (such as parts of the natural gas grid) and developing new sector-specific infrastructure (like hydrogen refuelling stations for road transport). Numerous regulations represent another significant barrier that limits the development of a clean hydrogen industry. New and updated standards coordinated between countries would help overcome this barrier, facilitating international trade in hydrogen and the development and commercialisation of hydrogen-based end-use technologies.

In addition, the accounting and verification of CO_2 emissions savings requires a robust methodology with certified standards to provide clarity to stakeholders and avoid double counting. Other barriers, such as social acceptance, potential environmental impacts and the availability of a specialised workforce, may be perceived as minor issues at times, but they can turn into major obstacles for achieving large-scale deployment of hydrogen technologies. Anticipating these barriers and adopting measures early to overcome them will help avoid problems in the future.

G20 recommendations

The Covid-19 outbreak and the resulting economic crisis are putting hydrogen deployment at risk. However, the economic stimulus packages that governments are designing to revitalise their economies can provide a powerful boost to accelerate the deployment of hydrogen at scale, setting the groundwork for clean energy transitions in the years ahead.

In 2019 the IEA identified four near-term opportunities to boost hydrogen on the path towards its widespread use as a clean resource. In the current context where the priority is securing economic recovery, these opportunities for hydrogen are even more important. Not only would they advance the adoption of clean hydrogen, but could also become important generators of economic growth and job creation. The following are our recommendations:

1. **Industrial ports** account for a significant proportion of current hydrogen demand. Making these hubs the **nerve centres for scaling up the use of clean hydrogen** would encourage large consumers to switch to low-carbon hydrogen. These hubs are well suited to the deployment of carbon capture, utilisation and storage (CCUS) infrastructure, which is fundamental for the large-scale production of low-carbon hydrogen in the short term. The co-location in these ports of activities that need CCUS to decarbonise would unlock synergies to maximise the utilisation of new infrastructure. It would also optimise costs and create jobs.

   Ports can also offer the opportunity for large-scale deployment of electrolysis, fed by offshore renewable electricity. The use of the stimulus packages to support electrolyser manufacturing can drive down their cost and facilitate their deployment on a large scale at these hubs. Electrolysis manufacturing is a capital-intensive activity and not necessarily a major job creation engine. But it can indirectly create a significant number of additional jobs across the whole supply chain and in the development and maintenance of related infrastructure.

2. **Utilising existing infrastructure,** such as natural gas grids, can generate low-carbon hydrogen demand at low cost. It can secure a significant market not only for low-carbon hydrogen production, but also for technology providers, such as electrolyser manufacturers. This would create synergies with any policies implemented to support manufacturers of technologies for low-carbon hydrogen production. For example, in the case of electrolysers, the main driver to reduce equipment cost is their deployment on a large scale. Stimulus packages could accelerate the deployment of electrolysers, significantly helping achieve cost reductions and opening opportunities for decarbonisation in numerous sectors.

3. The fuel cell electric vehicle (FCEV) market grew strongly in 2019, albeit from a low base. **Deploying hydrogen in vehicle fleets and corridors** can improve the competitiveness of FCEVs by rapidly reducing costs. Recovery packages can be designed to support company fleets to switch to FCEVs, especially for heavier trucks where few other low-carbon options exist. These packages can also support the development of the necessary infrastructure (such as refuelling stations) to ensure stable and secure operation of the fleets along the corridors. Refuelling stations also offer the opportunity to deploy electrolysers beyond industrial hubs. Thanks to their modularity, electrolysers are highly suited to distributed hydrogen production, thus minimising the need for hydrogen transport infrastructure to supply the refuelling stations.

4. International trade is a pillar of a secure energy system and **launching international shipping routes for hydrogen** is a necessary step in this direction. It would facilitate access to affordable hydrogen in regions where domestic production is particularly expensive. In addition, it presents a significant opportunity for job creation at ports, with the construction or adaptation of infrastructure, and in auxiliary services and industries. The development of international trade will increase the need for the accounting and verification of emissions savings. International engagement will be needed to ensure that these standards are globally adopted.

Strengthening the momentum behind hydrogen in the short term will set the groundwork for adopting low-carbon hydrogen in the future. However, it is important to stay farsighted and be prepared for challenges and opportunities. It seems likely that many will emerge around the use of hydrogen in sectors where emissions are hard to abate – where other scalable low-carbon technologies are either not available, or the challenges associated with implementing them are high. Demand-pull policy instruments tailored to priority applications will be required to facilitate the uptake of hydrogen. These applications include domestic and industrial heat; chemical feedstock and steel manufacture; and fuels for shipping and aviation.

Learning-by-doing and economies of scale will create cost reductions, but continuous innovation will be crucial to reduce costs and improve hydrogen's competitiveness. Innovation in areas like electrolysers and fuel cells presents synergies and potential spillovers with other clean energy technologies, such as batteries. There are opportunities to shorten the time required to become competitive. They could be exploited with the right coordination and government action, which is critical in setting the research agenda, sharing risks and attracting private capital for innovation.

Governments should define and coordinate their near- and long-term actions to ensure that hydrogen achieves its potential. This will require establishing a role for hydrogen in long-term energy strategies, setting targets and making commitments. These will send a clear message to guide stakeholders' expectations and provide certainty of a future market for hydrogen. There will be no one-size-fits-all strategy and governments should consider social and political priorities and constraints facing them, as well as resource availability. Whatever the priorities defined in the strategy, the signals they send to stakeholders will be stronger if their ambition and timing are aligned across different levels of government, and at an international level among countries.

01

Introduction

A. Hydrogen as an energy carrier

In recent years governments, industry and society have become increasingly aware of the need to put the energy system on a more sustainable pathway. This has revived interest in hydrogen and its potential role as a clean fuel and feedstock. Hydrogen is enjoying unprecedented momentum. Several countries – including Australia, Germany, Japan, Korea and the Netherlands – have put forward hydrogen strategies in the last three years, with more countries announcing plans to publish their strategies in 2020. They are aiming to position themselves at the forefront of this transformation.

Hydrogen is already a major global business and demand for it has grown continuously in recent decades, especially for oil refining and chemical production (IEA, 2019a). However, the potential of hydrogen as a versatile fuel involves a much wider set of applications and sectors across the energy system. This potential has given rise to interest among different stakeholders, from national and regional governments to manufacturing industries, oil and gas companies, and the automotive sector. These stakeholders have found in hydrogen technologies a strong candidate as they look for ways to meet their decarbonisation goals and overcome the challenges that the transition towards a sustainable energy system is facing:

- Hydrogen can support the integration of greater amounts of variable renewable energy in the electricity system, helping to tackle the temporal and geographical mismatch between availability and demand. It is a promising alternative to long-term electricity storage in particular, and can be used for generating back-up power in periods of high demand and low renewable energy availability.

- Hydrogen can be used as a low-carbon fuel in sectors where delivering meaningful reductions in GHG emissions is proving to be very difficult, such as long-haul transport and heavy industry, where direct electrification has a limited applicability.

- Hydrogen does not emit particulate matter or sulphur dioxide when combusted and causes no pollutants at all when used in fuel cells, so it can also help improve air quality, especially in urban areas where this has become a major public health problem.

- Hydrogen can be produced from all sources of energy and can be used directly as a fuel or converted into other products for energy applications. This versatility promotes the diversification of energy sources and use, contributing to improved energy security.

Hydrogen was in the spotlight in the 1970s, due to the oil price shocks, and in the 1990s and early 2000s, when concerns about climate change started arising. However, hydrogen did not live up to expectations as a result of several factors, including the low maturity of key hydrogen technologies, relatively low oil prices and the lack of strong enough environmental drivers.

This time, there are significant signs to suggest that a more positive outcome is possible. Hydrogen technologies have developed up to the point where many of them can be deployed at scale and deliver cost reductions to increase competitiveness. In addition, governments and industry have made stronger commitments to deliver deep emission reductions in response to societal demands. However, realising the full potential of hydrogen will require several key challenges to be overcome:

- Practically all the hydrogen currently produced is sourced from unabated fossil fuels, resulting in significant CO_2 emissions. Hydrogen can only contribute to decarbonisation efforts if it is produced from low-carbon sources.

- The cost of low-carbon hydrogen is still higher than that of hydrogen produced from unabated fossil fuels, although cost reduction prospects look promising if relevant technologies can be deployed at scale.

- The development of relevant infrastructure has been slow to date, preventing widespread adoption of hydrogen in several sectors.

- Several regulations are becoming an unnecessary barrier to the adoption of low-carbon hydrogen.

Overcoming these challenges and realising the benefits that hydrogen can deliver are paramount to tap into its potential for a cleaner and more resilient energy system, as foreseen in the circular carbon economy discussed under the G20 Presidency of the Kingdom of Saudi Arabia. In this report, we discuss the current status of hydrogen technologies and the place these technologies would take in a circular carbon economy.

B. The role of hydrogen in a circular carbon economy

The high versatility of hydrogen gives rise to a very complex supply chain involving several interlinked processes, energy sources and products (Figure 1). These processes interact with different elements of a circular carbon economy. However, these interactions can lead to positive or negative impacts depending on how the supply chain is designed and which technologies are deployed.

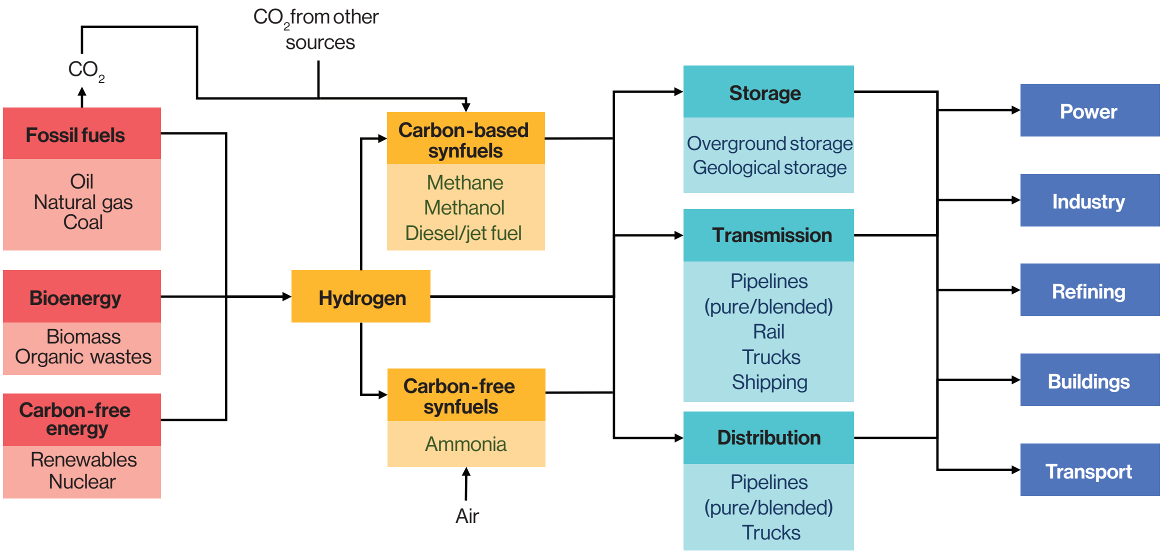

Figure 1. Schematic of the hydrogen supply chain
Hydrogen is a very versatile fuel. This results in benefits for energy security, but also in a highly complex and interconnected supply chain.

There is a place for unabated fossil-based hydrogen in the near term, while hydrogen demand is developed in new applications and access to competitive supplies of hydrogen is ensured. However, tapping into its full potential as a clean energy source in the longer term will require the adoption of low-carbon hydrogen sources. Otherwise, the carbon footprint of hydrogen in new applications could end up being larger than that of competing technologies.

Switching hydrogen production to technologies that incorporate carbon capture, water electrolysis powered by low-carbon electricity, and other low-carbon options (such as biomass or thermochemical water splitting) can transform hydrogen into an enabler of a cleaner energy system. In the context of the Four Rs of the circular carbon economy concept (Williams, 2019) of the G20 Saudi Arabia Presidency, hydrogen could play a crosscutting role (Figure 2):

- **Reduce:** substituting high-carbon fuels with low-carbon hydrogen can reduce the carbon entering the system. Replacing hydrogen produced by conventional routes in current uses – for example, by retrofitting CCUS at existing fossil fuel-based hydrogen production plants – and expanding the use of low-carbon hydrogen in new applications can deliver reductions in GHG emissions.

- **Recycle:** hydrogen-derived synthetic hydrocarbons can directly replace conventional fossil fuels such as diesel or kerosene. These synthetic fuels are produced by combining carbon with hydrogen; using captured CO_2 would enable a route for carbon recycling.

- **Reuse:** CO_2 captured during the production of hydrogen from fossil fuels or biomass can be reused in applications such as enhanced oil recovery or supercritical CO_2 power.

- **Remove:** the production of hydrogen from biomass with carbon capture and storage removes CO_2 from the system and can give rise to negative CO_2 emissions.

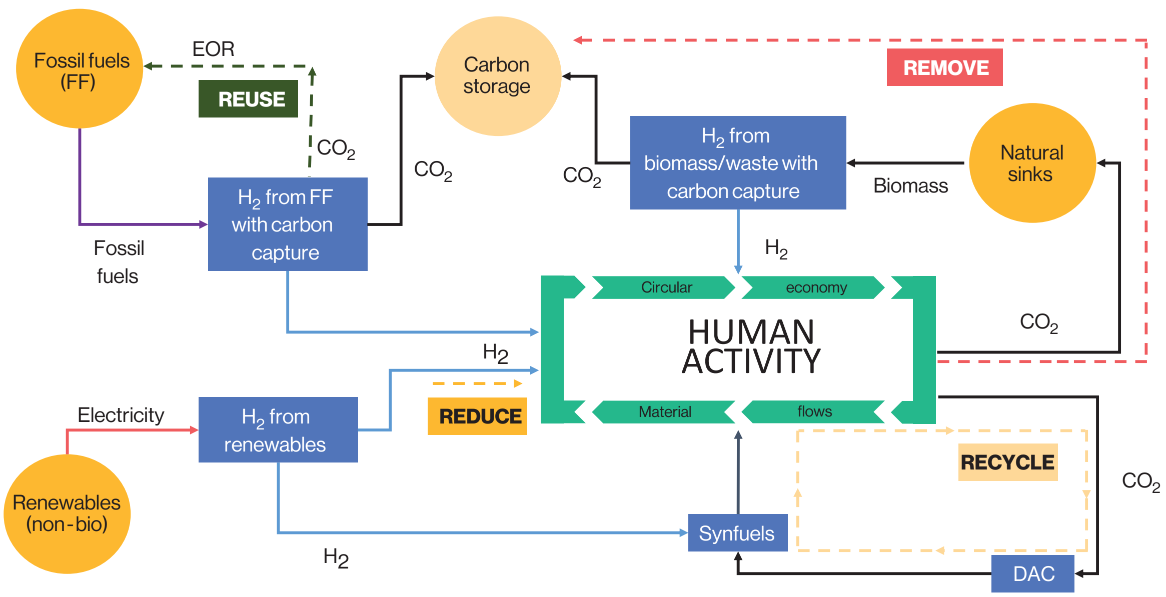

Figure 2. Hydrogen technologies in the context of a circular carbon economy.

Hydrogen could play a crosscutting role across different elements of a circular carbon economy.

Notes: DAC = direct air capture. EOR = enhanced oil recovery. FF = fossil fuels.

02

Hydrogen demand: Status and prospects

A. Hydrogen use today

Hydrogen is usually perceived as a fuel for the future, but it is already a big industry that has been part of the energy system for a long time. Around 75 Mt of pure H_2 and 45 Mt H_2 mixed with other gases are consumed annually. This demand has grown over recent decades, with three sectors responsible for about three-quarters of hydrogen demand: chemical production, oil refining, and iron and steel production (Figure 3).

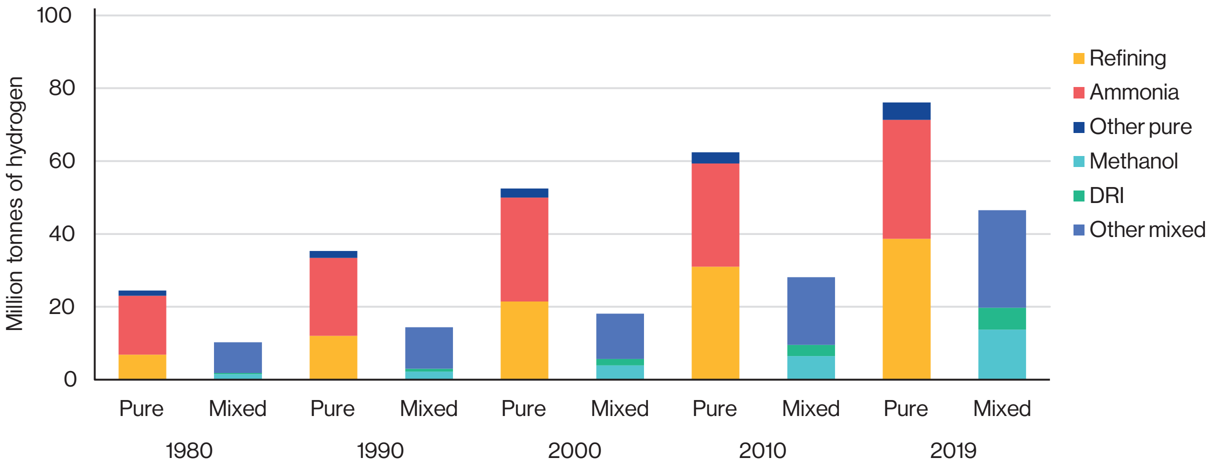

Figure 3. Evolution of annual demand for hydrogen, 1980-2019

Around 75 Mt of pure hydrogen and 45 Mt of hydrogen mixed with other gases are consumed annually, mainly in the chemical sector, oil refining, and iron and steel production.

Note: DRI = direct reduction of iron.

Source. Modified and updated from IEA 2019a.

The chemical industry is the largest consumer of hydrogen, with demand of more than 50 Mt H_2 in 2019. Most of this hydrogen is used in the production of ammonia (33 Mt of pure H_2), mainly for fertiliser production, and methanol (14 Mt H_2 mixed with other gases), which is an important feedstock for the chemical sector and fuel production.

Oil refining is the next largest consumer of hydrogen. Around 39 Mt H_2 are used every year in hydrotreatment and hydrocracking of oil to remove impurities and to upgrade heavy fractions into lighter products.

Steel production is another important source of hydrogen demand, mainly as a reducing agent in DRI steel production. The production of steel through this route has grown about 12% more rapidly than total crude steel production over the last decade. DRI uses hydrogen mixed with other gases as a reducing agent in the production of iron, although some pilot projects are studying the feasibility of using pure hydrogen. Other sectors where hydrogen is used at small scale include glass, metal, petrochemical and electronics manufacturing.

In addition, there are several emerging applications where hydrogen demand is still low, but where its use is attracting a lot of interest, such as transport, buildings, industrial heat and power generation. This interest from sectors where emissions are hard to abate is based on the potential of hydrogen to deliver GHG emission savings. The adoption of hydrogen in these new applications could be a cornerstone of a low-carbon energy system.

B. Hydrogen demand prospects

Hydrogen demand is generally expected to grow significantly, both in traditional and potential new applications. However, the economic downturn from the outbreak of the Covid-19 crisis means that hydrogen use in traditional applications is set to drop in the short term. Those sectors that are already major hydrogen consumers are being seriously impacted by the crisis.

Oil is one of the most affected sectors, with demand expected to plummet by 7.9 mb/d in 2020. Recent IEA forecasts suggest declines for gasoline (9%), diesel (6%) and jet fuel (37%) consumption in 2020, with the near-term outlook depending on the duration of the outbreak, the potential for second waves and the strength of the subsequent restart of economic activity (IEA, 2020a; IEA, 2020b). This would represent a fall in hydrogen demand for oil refining from 39 Mt H_2 in 2019 to 36 Mt H_2 in 2020 (almost 7% down).

Similarly, the chemical and steel sectors are also being affected. Demand for methanol and ammonia are expected to fall by 7% and 5% respectively compared to 2019. The World Steel Association forecasts that steel demand will contract by 6.4% in 2020, with a partial recovery in 2021 leading to growth of 3.8% over 2020 (WSA, 2020). India, the largest DRI-producing country, has been especially affected, with an expected 18% drop in output in 2020. The evolution of the crisis in coming months will shape the trend for hydrogen demand in the near future.

Such drops in hydrogen demand in traditional applications do not necessarily mean that a transition to clean hydrogen production and more widespread use will also be slowed by the pandemic. However, these sectors will be critical actors in the transition from CO_2-intensive to low-carbon hydrogen production and demand because they can enable the scale-up of low-carbon hydrogen. This particularly applies to those uses where hydrogen is already consumed and for which low-carbon hydrogen would be a drop-in commodity (e.g. chemicals and hydrogen blending in steelmaking processes up to a certain level).

Several major players in the oil, chemical and steel sectors announced plans and demonstration projects to embrace this transition (Table 1). However, many projects are currently in construction or planning, and could face delays related to the Covid-19 pandemic. Factors such as the slowdown in the economic activity resulting from lockdowns and social distancing, the disruption of supply chains, or lower capital expenditure by companies forced to prioritise other business areas, could put these and other future developments at risk.

Project	Region	Timeline	Sector	Description
HESC demo**	Australia Japan	2015-20	Trade	Intercontinental hydrogen transport. Hydrogen produced from coal gasification in Australia and transported to Japan using a liquid hydrogen carrier vessel.
HYBRIT**	Sweden	2016-25	Steel	Steel production through DRI with hydrogen produced from electrolysis using low CO_2 intensity electricity.
Yara green ammonia production*	Norway	2019-22	Chemical	Production of fertiliser using low-carbon hydrogen produced from renewable electricity.
REFHYNE*	Germany	2018-22	Oil refining	Use of hydrogen produced through electrolysis for processing and upgrading products in a refinery.
Norled hydrogen ferry**	Norway	2019-21	Shipping	Two ships propelled by 400 kW fuel cells will start operating in 2021 for transporting passengers and cars. Storage will be based on compressed and liquid hydrogen.
Hydrocat**	The Netherlands	2019-20	Shipping	Use of dual-fuel combustion engine, able to combust both diesel and hydrogen, in a passenger transport ship.
HyNet fuel switching * / **	United Kingdom	2020-21	Industry and oil refining	Demonstration of switching from natural gas to hydrogen in glass production, health products manufacture and oil refining.
H2M**	The Netherlands	2018-25	Power	Use of hydrogen produced from natural gas combined with CCS for power generation using gas turbines.

Table 1. Selected demonstration projects under development for drop-in and new applications of hydrogen

Notes: * drop-in applications; ** new applications; kW = kilowatt; CCS = carbon capture and storage.

Sources: BEIS (2020); CMB (2019); HESC (2020); HYBRIT (2020); Norled (2019); REFHYNE (2020); Vattenfall (2018); Yara (2020).

The use of hydrogen in new applications – such as transport, power generation, energy storage and domestic heating – was also starting to accelerate before the Covid-19 outbreak. The FCEV market witnessed impressive growth in 2019, although it remains considerably smaller than battery electric and hybrid vehicle markets. Total sales of FCEVs in 2019 reached 12 350 units, bringing the global stock to more than 25 000 units, doubling the figures from 2018 (IEA, 2020c).

The use of hydrogen in buses and trucks is gaining traction, with several announcements for projects aiming to deploy thousands of vehicles in early 2020s. They include the H2Bus Consortium's proposal to deploy 1 000 fuel cell buses in Europe and Hyundai's plans to deploy 1 600 trucks in Switzerland by 2025 (H2Bus, 2020; Hyundai, 2020). Two hydrogen trains became operational in 2018 in Germany and up to 41 units are expected to be deployed between 2021 and 2023. More countries in Europe and Asia have announced plans to start operation of hydrogen-fuelled trains (IEA, 2020d).

It is important to note that there is significant potential for spillover in fuel cells between light- and heavy-duty road vehicles, and even from non-road industrial vehicles such as forklifts, cranes, excavators and auxiliary power units. This means that economies of scale and innovations could be leveraged across all these types of vehicle.

Opportunities are also emerging in maritime transport for hydrogen or hydrogen-based fuels, such as ammonia, due to the decision of the International Maritime Organization to set a CO_2 emissions reduction target.[1] More than 25 demonstration projects for hydrogen or hydrogen-derived fuel propulsion are under development across the world.

The use of hydrogen in domestic heating is still low, but is expanding. The stock of hydrogen-ready equipment is increasing, with more than 300 000 hydrogen-ready fuel cell units deployed in Japan alone. Several projects around the world are already injecting hydrogen into gas grids, with many more in the pipeline expected to become operational in the short term (IEA, 2019a).

In the power sector, the role of hydrogen remains negligible, although there is potential for this to change in the future. Co-firing with ammonia could reduce the carbon intensity of existing conventional coal power plants, and hydrogen gas turbines or engines could be a source of flexibility in electricity systems with increasing shares of variable renewable generation. Compressed hydrogen or other hydrogen storage systems could become a long-term storage option to balance seasonal variations in electricity demand or generation from renewables.

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[1] The International Maritime Organization (IMO) Marine Environment Protection Committee (MEPC) announced that member states have agreed on a target to cut the shipping sector's overall GHG emissions by 50% by 2050 compared to 2008 and to reduce the carbon intensity of shipping activities by at least 40% by 2030 and 70% by 2050, compared to 2008 (IMO, 2016).

Despite these positive prospects, the Covid-19 pandemic presents the risk of slowing hydrogen's momentum in these new applications. According to media reporting, in the first four months of 2020 fuel cell car sales dropped by 7% in China, 12% in Japan and 65% in the United States compared with the same period in 2019. Achieving hydrogen's maximum potential as a clean energy solution will depend on creating demand for it in these new applications, which in turn relies on the progress of many of the demonstration projects currently under development (Table 1). So far, there have been no announcements of serious pandemic impacts on critical demonstration projects, with only minor delays from slower activity caused by lockdowns. On the contrary, some technology suppliers have announced plans to accelerate the development of hydrogen technologies. Volvo and Daimler announced in April a joint venture to work on hydrogen fuel cells for trucks, and Bosch announced plans to manufacture fuel cells for mobile and stationary applications in their response to the Covid-19 crisis (Daimler, 2020; Bosch, 2020).

Box 1

The role of governments in the future of hydrogen after Covid-19

"The Future of Hydrogen" report highlighted the strong political support for hydrogen and recommended establishing a role for hydrogen in long-term energy strategies to guide future expectations (IEA, 2019a). Several governments had already shown a commitment to low-carbon hydrogen technologies, announcing national hydrogen roadmaps and implementing an increasing number of policies supporting investment in hydrogen technologies. This trend has continued since then, and more countries have announced hydrogen strategies, roadmaps and partnerships, in many cases establishing targets for the deployment of hydrogen technologies.

The economic downturn caused by Covid-19 may act as a brake on hydrogen's unprecedented political momentum. So far, there have been some positive signals suggesting that it could also be an opportunity to accelerate the development of low-carbon hydrogen technologies. The European Union included hydrogen among the technologies that will play an important role in its Covid-19 recovery plan, Australia has established the Advancing Hydrogen Fund (AUD 300 million) to support hydrogen projects and Portugal announced plans to build a large solar-powered hydrogen plant with an estimated investment of EUR 5 billion.

Keeping up this momentum and including hydrogen in stimulus packages for recovery from the Covid-19 crisis have the potential to create jobs across the entire supply chain, to strengthen the hydrogen industry after the crisis and to lay the groundwork for low-carbon hydrogen to have a critical role in the energy transitions in the years ahead.

Selected hydrogen-related policy announcements in 2019 and early 2020	
Country	**Description**
Australia	November 2019 – Published the National Hydrogen Strategy, defining 57 actions in areas such as regulation, infrastructure, mobility and R&D, aiming to position Australia as a world leader in hydrogen production and exports. April 2020* – Announced the Advancing Hydrogen Fund with up to AUD 300 million to support hydrogen-powered projects.
Canada	October 2019 – Published the paper "2019 Hydrogen Pathways – Enabling a Clean Growth Future for Canadians", defining ten high-level actions to make hydrogen and fuel cell technologies part of the clean growth solutions that provide environmental and economic benefits to Canadians.
European Union	March 2020* – The European Commission proposed the launch of a European Clean Hydrogen Alliance bringing investors together with governmental, institutional and industrial partners to identify technology needs, investment opportunities and regulatory barriers and enablers. May 2020* – The European Commission put forward a proposal for a major recovery plan from the Covid-19 crisis, which includes the adoption of policies for kick-starting a clean hydrogen economy in Europe. July 2020* – the European Commission announced a new Hydrogen Strategy, setting out a hydrogen roadmap for Europe, adopting ambitious deployment goals and creating the European Clean Hydrogen Alliance to help deliver on the strategy and build up an investment pipeline for scaled-up clean hydrogen production.
Germany	June 2020* – Published the National Hydrogen Strategy, establishing ambitious targets in several sectors and defining 38 measures to achieve them.
The Netherlands	June 2019 – Presented the National Climate Agreement, including an agreement to formulate a National Hydrogen Programme and setting targets for power generation and mobility by 2025 and 2030. April 2020* – Published the Government Strategy on Hydrogen, setting a policy agenda to support the development of the hydrogen sector aiming to shape the basic conditions for the growth of hydrogen by 2025.
Portugal	May 2020* – Launched a consultation for a draft of the national strategy that included targets, including meeting 5% of final energy consumption with hydrogen in 2030.
Clean Energy Ministerial	May 2019 – launch of a new hydrogen initiative aiming to boost international collaboration on policies, programmes and projects to accelerate the commercial deployment of hydrogen and fuel cell technologies. Canada, Japan, the Netherlands, the United States and the European Commission are co-leading the initiative with the coordination of the IEA.
Hydrogen Energy Ministerial	September 2019 – 35 countries and international organisations agreed to the Global Action Agenda to guide expanded RD&D on hydrogen and setting a target to reach 10 million hydrogen vehicles and 10 000 hydrogen refuelling stations in ten years.

* Indicates policies announced after the Covid-19 outbreak.

03

Hydrogen supply: Current status and outlook

A. Hydrogen production technologies

Hydrogen can be produced with a wide variety of technologies and sources, although global production is dominated by fossil fuels (IEA, 2019a). Most of today's hydrogen production is from natural gas and coal, with small contributions from oil and electricity. Biomass is also an interesting source for hydrogen generation, but its use presents challenges (Box 2).

Natural gas accounts for around 75% of the annual dedicated production of pure hydrogen and is also the main route for producing hydrogen used in gas mixtures. Hydrogen can be produced from natural gas using three technologies. The most widely used is steam methane reforming (SMR), which uses high-temperature steam as an oxidant and source of hydrogen. The other two technologies are partial oxidation (POx), which uses oxygen or air as oxidant, and autothermal reforming (ATR), which is a combination of SMR and POx. All these processes give rise to synthesis gas or syngas, which is a mixture of hydrogen, carbon monoxide and small fractions of light hydrocarbons. This syngas can be used directly in certain processes, like methanol production or DRI, or be used to produce pure hydrogen.

Coal is the other major source of hydrogen production worldwide, due to its dominant role in the chemical and steel industries in China. Around 23% of the dedicated production of pure hydrogen is based on coal, using gasification. In this process, an oxidant (oxygen, air, steam, CO_2 or combinations of them) reacts at high temperature with coal to give rise to a syngas similar to that from natural gas-based routes, but with poorer hydrogen content.

Natural gas and coal are responsible for the vast majority of the CO_2 emitted in the production of hydrogen. CCUS technologies can be applied to both production routes to decrease their carbon footprint. However, uptake is still low since it entails a cost penalty, which depends on the hydrogen production process and the carbon capture rate. The use of CCUS is practically limited to ammonia/urea plants where concentrated CO_2 streams from SMR are captured and used in the production of urea fertiliser.

Hydrogen can also be produced by water electrolysis, an electrochemical process in which electricity is used to split water into hydrogen and oxygen. Water electrolysis accounts only for around 0.1% of hydrogen production and it has been traditionally limited to applications that require high-purity hydrogen, such as electronics. Additionally, around 2% of total global hydrogen production is obtained as a by-product of chlor-alkali electrolysis in the production of chlorine and caustic soda.

Box 2

Biomass and waste as a source for hydrogen production

The production of hydrogen from biomass or waste is attractive from the perspective of the circular carbon economy since it offers the possibility of delivering carbon negative emissions when coupled with CCUS, thus enabling the recycling and removal of carbon from the energy system. However, this production route is still at early stages and short-term prospects are uncertain due to technology challenges and feedstock availability. Moreover, the production of hydrogen from biomass will face strong competition for biomass resources from more efficient biofuel technologies that are closer to commercialisation

Two types of routes can be used to obtain hydrogen from biomass:

1. **Biochemical routes,** based on the decomposition of organic matter by microorganisms. The most developed technology is anaerobic digestion, which produces biogas and can only process certain feedstocks (such as sewage sludge or agricultural and food waste). Fermentation is a less developed technology that can process the non-edible cellulosic part of plants and gives rise to a combination of acids, alcohols and gases. Other technologies such as metabolic processing still remain at very early stages of development.

2. **Thermochemical routes,** based on the breakdown of the organic matter in the presence of high temperatures and, occasionally, oxidants. Biomass gasification is the most developed technology. It produces syngas from solid materials and can potentially process all organic matter. Despite the similarities with coal gasification, biomass gasification for hydrogen production is still a relatively immature technology. There are some demonstration plants around the world, but unsolved technical challenges remain, such as catalyst poisoning by tars.

   Pyrolysis is a technology similar to gasification, although it does not involve the use of any oxidant. It produces a combination of bio oil, gases and a carbonaceous residue, with bio oil being the fraction with higher yields. For this reason, pyrolysis seems to be better fit for the production of bioliquids. Other promising technologies, such as hydrothermal processing, are still far from being demonstrated at significant scale.

All these routes generate products that require further processing to obtain hydrogen, resulting in low efficiencies and high costs. The economic feasibility of practically all the projects under development relies on gate fees from waste processing due to the high price of biomass. This limits the opportunity for scaling up due to restricted feedstock availability, thus limiting the cost reduction potential from the economies of scale. The feasibility of large-scale production of hydrogen from biomass will depend on the availability of cheap biomass and technological developments to improve performance and reduce costs.

Economics of hydrogen production

Fossil fuel technologies dominate hydrogen production due to the lower production costs that SMR and coal gasification can deliver in comparison with electrolysis (Figure 4). Hydrogen production costs via unabated SMR are in the range of USD 1-1.9/kg H_2, and depend mainly on the price of natural gas (45-70% of production costs). For unabated coal gasification, hydrogen production costs are in the range of USD 1.6-1.8/kg H_2, but in this case the capital costs (CAPEX) and operational cost (OPEX) are the main contributors to the production cost.

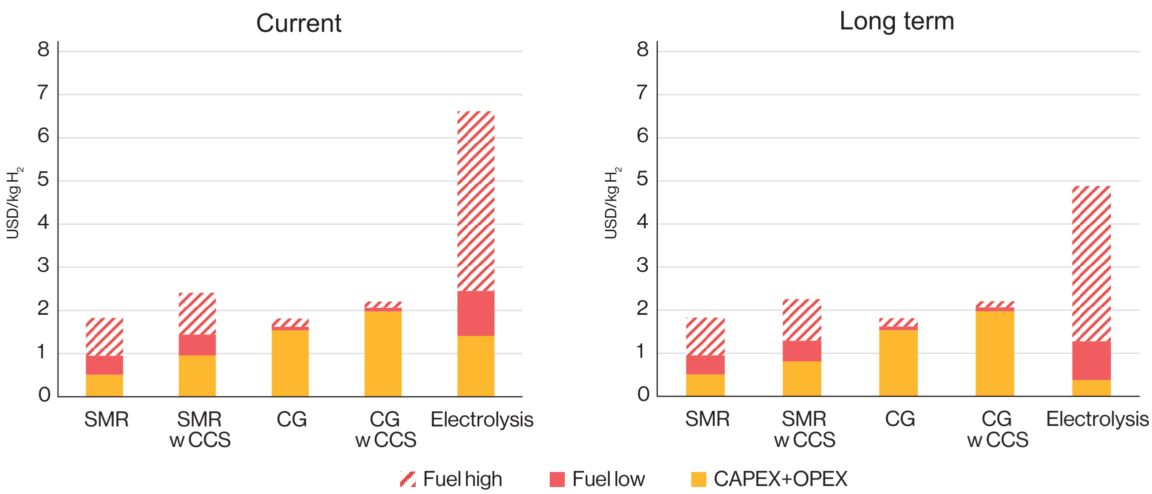

Figure 4. Current and long-term levelised cost of hydrogen production with different technologies

Fossil-based hydrogen is currently 2-4 times cheaper than electrolytic hydrogen, although electrolysis offers a large cost reduction potential.

Notes: SMR = steam methane reforming; CG = coal gasification.

Assumptions: 8% discount rate, 25-year system lifetime, natural gas price = USD 3-9/MBtu, coal price = USD 18-48/toe, electricity price = USD 20-100/MWh.

SMR CAPEX = USD 910/kW_{H_2} (current and long term), OPEX = 4.7% of CAPEX, 76% efficiency, 95% load factor.

SMR w CCS CAPEX = USD 1 583/kW_{H_2} (current), USD 1 282/kW_{H_2} (long term), OPEX = 3% of CAPEX, 69% efficiency, 95% load factor, 90% capture rate.

CG CAPEX = USD 2 672/kW_{H_2} (current and long term), OPEX = 5.0% of CAPEX, 60% efficiency, 95% load factor.

CG w CCS: CAPEX = USD 2 783/kW_{H_2} (current and long term), OPEX = 5.0% of CAPEX, 58% efficiency, 95% load factor, 90% capture rate.

Electrolysis CAPEX = USD 1 069/ kW_e (current), USD 355/ kW_e (long term), OPEX = 2.2% (current) 1.5% (long term) of CAPEX, efficiency = 64% (short term), 74% (long term), 5 000 full load hours.

The production of hydrogen via coal gasification and SMR is very carbon intensive and requires the incorporation of CCUS to decrease its carbon emissions. This leads to an increase in the production cost, the magnitude of which depends on the capture rate (Figure 5). This cost increase is the result of larger CAPEX investment and, to a lesser extent, of the lower efficiencies that increase the costs associated with natural gas and coal consumption. Ammonia/urea production plants are already achieving capture rates of around 60%, but higher carbon capture would be needed to ensure that hydrogen use delivers significant carbon savings against incumbent technologies, especially in new applications. Advanced technologies, such as coupling gas-heated reformers with autothermal reformers, can achieve up to 97% carbon capture. This will eliminate much of the carbon footprint of hydrogen production from natural gas, although the cost increase would further decrease the competitiveness of the process compared with unabated technologies.

The adoption of carbon prices can help to close the gap between processes incorporating CCUS and unabated processes. Moreover, if carbon prices are high enough they can make the adoption of CCUS technologies with high capture rates more economic, contributing to the achievement of lower carbon footprints.

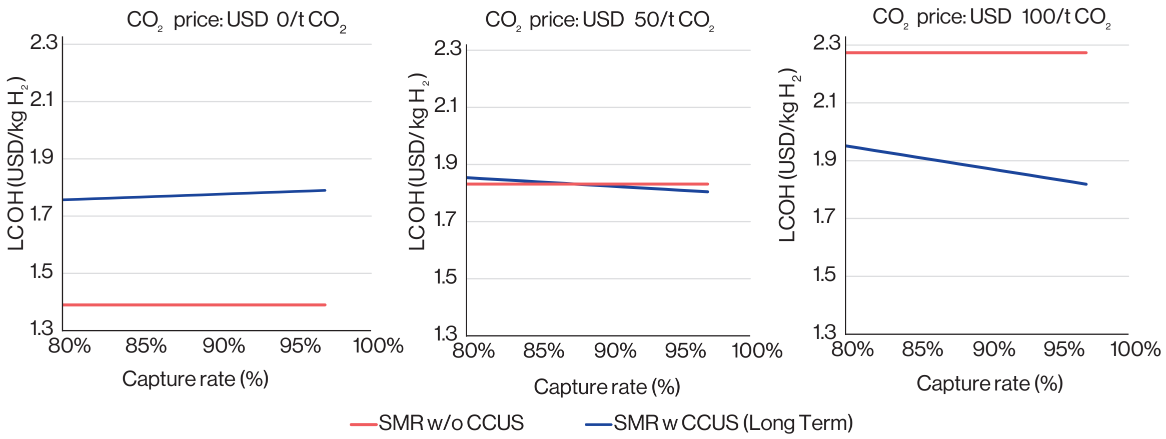

Figure 5. Projected levelised cost of hydrogen from SMR with and without CCUS for different CO_2 prices

For hydrogen from natural gas with CCUS to be cheaper than unabated production, high CO_2 prices are needed.

Notes: LCOH = levelised cost of hydrogen. Based on 8% discount rate, 25-year system lifetime, natural gas price = USD 6/MBtu, 95% load factor, CO_2 capture and storage cost = USD 20/t CO_2. SMR: CAPEX = USD 910/kW_{H_2}, OPEX = 4.7% of CAPEX, 76% efficiency. SMR w CCS: CAPEX = USD 1 282/kW_{H_2} (long term), OPEX = 3% of CAPEX, 69% efficiency.

Water electrolysis is also a route for low-carbon hydrogen production, although only if low-carbon electricity is used to power the electrolyser. Hydrogen production from water electrolysis is very low today because the production cost is 2-4 times higher than for fossil-derived hydrogen. The cost of electrolytic hydrogen depends on several factors, including the cost of electricity, the load factor, the efficiency of the electrolyser and the CAPEX.

The weight of capital costs within the final cost of hydrogen is currently very high, but electrolysers have high cost reduction potential through scale-up and learning effects if the technology is deployed at scale (Figure 4). This CAPEX reduction combined with optimum sizing and operational management of the electrolyser can minimise the impact of CAPEX in the cost of hydrogen production. This turns the cost of electricity into the main factor determining the final levelised cost of hydrogen (Figure 6). For this reason, the production of electrolytic hydrogen at competitive costs against fossil-based hydrogen will require the availability of low-cost electricity.

In the long term, it is expected that most electrolytic hydrogen production will be based on the use of dedicated renewable electricity in areas with high renewables potential. Therefore, the majority of the production facilities will have access to low-cost electricity and the levelised cost of hydrogen will be closer to the lower end of the range shown in Figure 4.

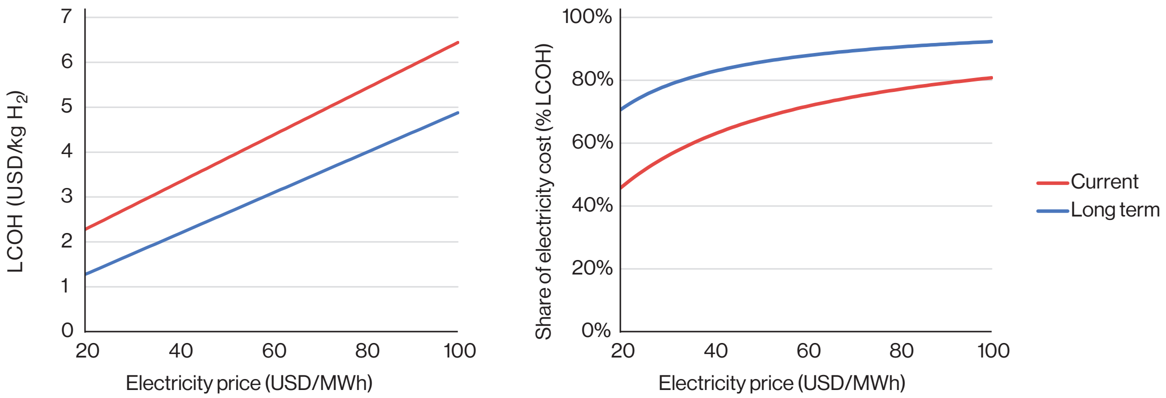

Figure 6. Share of electricity cost in current and future projected levelised cost of electrolytic hydrogen

If water electrolysis is deployed at scale, the impact of CAPEX can be minimised and electricity will become the main cost component.

Notes: Assumes 8% discount rate, 25-year system lifetime, 5 000 full load hours, OPEX = 2% of CAPEX. CAPEX = USD 1 000 kW_e (current), USD 350/kW_e (long term). Efficiency = 64% (current), 74% (long term).

Box 3

The impact of the Covid-19 crisis on the development of low-carbon hydrogen supply

The impressive momentum behind hydrogen is also reflected on the supply side. The number and size of low-carbon hydrogen production projects have been growing in the last decade and several announcements of large-scale deployment have been made for the next decade. Certain projects are conducting feasibility studies or are in planning phases, but many others are already under construction.

These projects may be at risk due to the Covid-19 crisis, hindering the deployment of low-carbon hydrogen production and the realisation of hydrogen's full potential as a low-carbon fuel. In addition to the risk factors mentioned in the demand section, low-carbon hydrogen production could face an additional barrier if the drop in oil and gas prices resulting from the crisis is prolonged. This would maintain a large cost gap with fossil fuels, which was one of the main reasons for previous false starts for hydrogen.

The initial response from stakeholders involved in low-carbon hydrogen production projects suggests mixed messages. Hydrogen Europe estimates that up to EUR 130 billion of investment in low-carbon hydrogen production projects may be at risk in Europe. However, major industrial players such as Shell, BP and Ørsted unveiled or even expanded their plans to develop major hydrogen-production projects (BP, 2020; Ørsted, 2020; Reuters, 2020). The evolution of the crisis over the coming months, the commitment of stakeholders to their hydrogen plans and the response from governments will together shape the future of the sector (Box 1).

B. Hydrogen-derived products

The storage and transport of hydrogen is considerably more difficult than that of fossil fuels due to the low energy density of hydrogen. However, it can be converted into hydrogen-based fuels and feedstock, such as synthetic hydrocarbon liquid fuels (synfuels), methane, methanol and ammonia. These products can be direct substitutes for their fossil equivalents or used as alternative fuels in new applications, as with ammonia, which can be used as hydrogen carrier or as a fuel, such as in shipping (IEA, 2019a).

The opportunity of these hydrogen-derived products will strongly depend on their production costs and their competitiveness against alternatives. Many technology pathways to synthesise these products are still at early stages of development, especially those based on the use of electrolytic hydrogen, leading to high production costs (Figure 7). Ammonia and methanol production from natural gas or coal are well-established routes that can incorporate CCUS to reduce their carbon intensity. Alternatively, ammonia, methanol and also methane and synfuels can be produced by combining clean electrolytic hydrogen with nitrogen, for ammonia, or a carbon input, for the other products. These routes present challenges due to the need to manage the variability of renewable power or the origin of the carbon source. In addition, these routes present low efficiencies from the electric input to the final product.

The long-term competitiveness of these hydrogen-derived products will depend on reductions in the cost of electrolysers, improvements in the transformation efficiency and the availability of low-cost clean electricity. The cost of electricity is particularly critical since it accounts for about 40–70% of the production costs. As with hydrogen, most production projects are likely to be placed in areas with high renewable resources and low-cost electricity, thus pushing production costs towards the lower end of the range shown in Figure 7.

However, an electricity price of just USD 20/MWh represents USD 60–70/bbl when used for synfuels production and USD 10–12/MBtu for methane. These costs are similar to the fossil fuel incumbents even without considering the contribution of CAPEX, OPEX, or the carbon feedstock costs. The adoption of CO_2 prices (or other policy instruments penalising the use of unabated fossil fuels, such as clean fuel standards) could help close the price gap with fossil fuel alternatives.

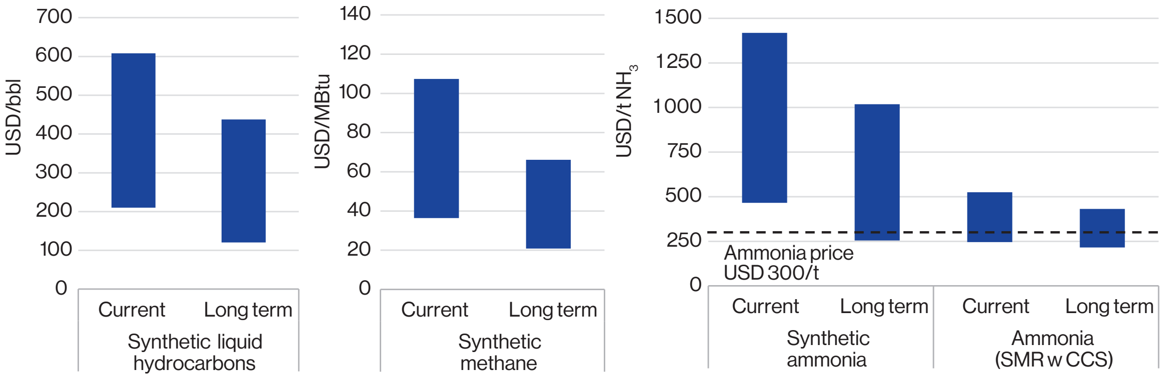

Figure 7. Current and future levelised cost of different hydrogen-derived products

Low fuel costs, efficiency improvements and CAPEX reductions will bring down the cost of hydrogen-derived products. Carbon feedstock costs are also critical for hydrocarbon products.

Note: Synthetic products based on the use of electrolytic hydrogen. Assumes 8% discount rate, 25-year system lifetime, natural gas price = USD 3-9/MBtu, electricity price = USD 20-100/MWh, CO_2 feedstock price = USD 30-150/t CO_2.
Electrolysis and SMR w CCS same assumptions as Figure 4.
Synthetic liquid hydrocarbons: CAPEX = USD 888/kW_{fuel} (current), USD 564/kW_{fuel} (long term), OPEX = 4% of CAPEX, 73% efficiency.
Synthetic methane: CAPEX = USD 843/kW_{fuel} (current), USD 564/kW_{fuel} (long term), OPEX = 4% of CAPEX, 77% efficiency.
Synthetic ammonia: CAPEX = USD 108/kW_{NH3} (current and long term), OPEX = 1.5% of CAPEX, 5.5 kg NH_3/kg H_2, electricity consumption = 4 GJ/t NH_3.
Ammonia, SMR w CCS: CAPEX = USD 1 164/t NH_3 (current), 1 304/t NH_3 (long term), OPEX = 2.5% of CAPEX, electricity consumption = 1.3 GJ/t NH_3 (current), 1.0 GJ/ t NH_3 (long term), gas consumption = 45.2 GJ/t NH_3 (current), 45.2 GJ/t NH_3 (long term).

C. Storage and transport

Hydrogen is currently most commonly stored as a compressed gas or liquid in tanks for small-scale mobile and stationary applications. However, the smooth operation of large-scale and intercontinental hydrogen value chains will require a much broader variety of storage options. At export terminals, hydrogen storage may be required for a short period prior to shipping, whereas vehicle refuelling stations will need several hours of hydrogen storage, and days to weeks of storage would be needed to protect end users against potential mismatches in hydrogen supply and demand. Much longer-term and larger storage options would be required if hydrogen was used to balance seasonal changes in electricity supply or heat demand.

The most appropriate storage alternative depends on the volume to be stored, the duration of storage, the required discharge rate and the geographic availability of different options. In general, geological storage is the best option for large-scale and long-term storage, while tanks are more suitable for short-term or intercontinental trade (IEA, 2019a).

Novel options to transport hydrogen from its point of production to end users are being developed. Like natural gas, pure hydrogen can be liquefied before it is transported, to increase storage efficiency. However, hydrogen liquefaction requires a temperature of -253°C, consuming one-third of the hydrogen energy content for small-scale systems of less than 5 t H_2/day. With further development, this energy penalty could be reduced down to one-fifth for large-scale systems (50-100 t H_2/day) (Ohlig and Decker, 2014). Such large systems still represent a much smaller scale than current natural gas liquefaction systems, suggesting that scaling up hydrogen liquefaction to the current scale of liquefied natural gas could improve the energy efficiency of the process further.

An alternative option is to incorporate hydrogen into larger molecules that can be more readily transported as liquids, such as ammonia or liquid organic hydrogen carriers (LOHC). Ammonia has a well-established international transmission and distribution network as a chemical product, but it is a toxic chemical. This may limit its use to certain end-use applications where professional handling is ensured and safety standards can be adhered to, such as the chemical industry, shipping or power generation, although there is a risk that some uncombusted ammonia could escape, resulting in air quality impacts. Converting hydrogen into ammonia and reconverting it back to hydrogen at destination is possible, but requires energy. Nevertheless, ammonia has advantages in that it liquefies at -33°C, a much higher temperature than hydrogen.

This temperature is still lower than for LOHC systems, in which hydrogen is "loaded" into a "carrier" molecule to produce a LOHC. These carriers can be transported and hydrogen extracted again at the destination. They have similar properties to crude oil and oil products, and can be transported as liquids without the need for cooling. However, the use of LOHCs requires the transporter to ship the carrier molecule back to its place of origin after extracting the hydrogen (IEA, 2019a).

IEA analysis indicates that, in the future, it may be cheaper in a number of instances to import hydrogen than to produce it domestically. For example, Japan currently imports around 90% of its energy needs and, as its Basic Hydrogen Strategy shows, hydrogen is seen as a source of energy security, emissions reduction and industrial leadership. This can bring about opportunities to import hydrogen from regions where the excellent renewable energy potential allows low-cost hydrogen production, such as Australia. Similarly, northern European countries could have the opportunity to import low-cost hydrogen from northern Africa and Mediterranean countries (Figure 8).

Transporting hydrogen from Australia to Japan and from the north of Africa to the north of Europe (including conversion and reconversion) would cost over USD 1.6/kg H_2 and USD 1.3/kg H_2 in the medium term, respectively. The distance of the trade route and the utility cost in both the exporting and importing countries are the main factors determining the total transport costs. The utility cost has a significant impact in the case of using LOHC or ammonia, since it increases the cost of the reconversion process.

In the long term, the cost of transporting hydrogen from Australia to Japan could fall to less than USD 1.4/kg H_2 and to less than USD 1.1/kg H_2 between the north of Africa and the northern of Europe. In the case of liquid hydrogen, this cost decrease will require efficiency improvements and scaling up to deliver CAPEX reductions. In the case of ammonia, the potential for direct use in sectors like power generation or maritime transport would allow users to avoid the additional reconversion costs, thus reducing the total transport cost to less than USD 0.5/kg H_2.

For many trade routes, the relatively high cost of hydrogen transmission and distribution means that it could often be cheaper to produce low-carbon hydrogen domestically rather than to import it. The higher cost of local hydrogen production from renewables or in combination with CCUS could outweigh the transport costs incurred for hydrogen imports. However, this also depends on local conditions, and countries with constrained CO_2 storage or limited renewable resources such as Japan will be more dependent on imports to cover their hydrogen demands.

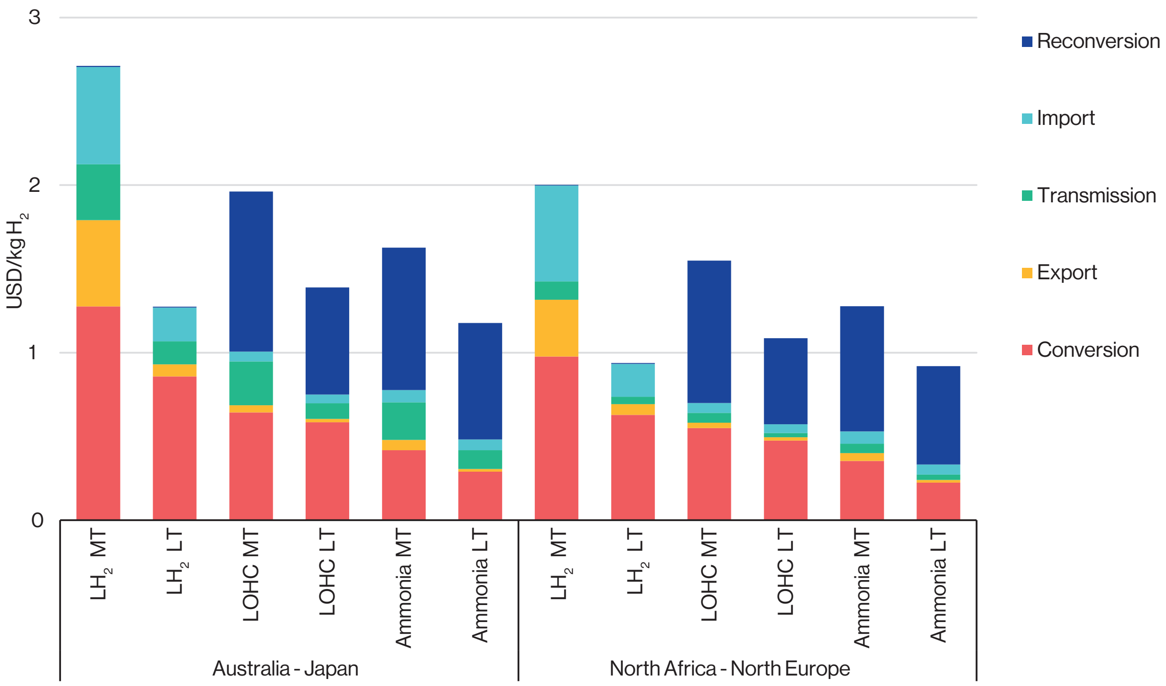

Figure 8. Projected cost of delivering liquid hydrogen, LOHCs and ammonia from resource countries to demand countries in the medium and long term

Further improvements in efficiency and scaling up can reduce transport costs by 25-50% and more in the long term.

Notes: MT = medium term. LT = long term. LH_2 = liquid hydrogen. Assumes distribution of 100 t/day in a pipeline to an end-use site 50 km from the receiving terminal. Storage costs are included in the cost of import and export terminals.
Low fuel costs, efficiency improvements and CAPEX reductions will bring down the cost of hydrogen-derived products. Carbon feedstock costs are also critical for hydrocarbon products.

Source. IEA analysis based on IAE (2016).

04

Carbon management potential

A. The carbon footprint of hydrogen and hydrogen-derived fuels

The role of hydrogen in a low-carbon energy system is linked to its production pathways. The integration of low-carbon production technologies would make hydrogen a crosscutting enabler of the low-carbon economy. Hydrogen would be a barrier if its production were based on conventional technologies.

The main hydrogen production technologies today, SMR and coal gasification, are carbon intensive. Hydrogen produced from SMR has a carbon intensity close to 9 kg CO_2/kg H_2, whereas coal gasification generates more than 20 kg CO_2/kg H_2 (Figure 9). Using CCUS can significantly decrease the emissions associated with these technologies. Capture rates of 90% can decrease the carbon intensity to below 1 kg CO_2/kg H_2 for SMR and around 2 kg CO_2/kg H_2 for coal gasification. Higher capture rates accordingly can enable even lower carbon intensities.

Water electrolysis does not emit CO_2 in the production of hydrogen, but the electricity used in the process has a carbon intensity associated with its production. Depending on the origin of the electricity used, the hydrogen produced can be low or high carbon. Low-carbon hydrogen can only currently be produced using dedicated renewable electricity (resulting in zero-carbon hydrogen) or grid electricity with very low-carbon intensity, which is available in a limited number of countries. Using electricity from fossil-based power generation results in the production of hydrogen with a higher carbon intensity than unabated fossil fuel pathways. The carbon intensity of grid electricity should be lower than 170 g CO_2/kWh to deliver hydrogen with a lower carbon intensity than hydrogen from SMR.

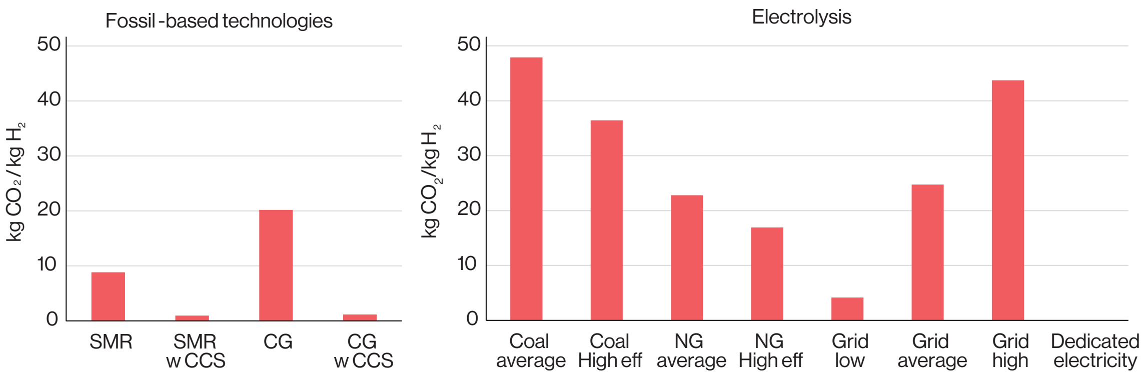

Figure 9. Carbon intensities of hydrogen production technologies

Electrolytic hydrogen can reach carbon intensities lower than fossil production routes with CCS. However, this requires the use of very low-carbon electricity.

Notes: CG = coal gasification. NG = natural gas. Dedicated electricity means the use of dedicated renewable electricity to power the electrolyser. Assumptions: efficiency (% lower heating value), SMR = 76%, SMR with CCS = 69%, CG = 60%, CG with CCS = 58%, electrolysis = 64%. Electricity carbon intensity (considers only generation and not full life-cycle analysis), coal average = 920 g CO_2/kWh, coal high efficiency = 700 g CO_2/kWh, NG average = 440 g CO_2/kWh, natural gas high efficiency = 325 g CO_2/kWh, grid electricity low = 80 g CO_2/kWh, average = 475 g CO_2/kWh, high = 840 g CO_2/kWh, dedicated renewable generation = 0 g CO_2/kWh.

Consequently, the carbon intensity of hydrogen-derived products will also depend on the production technology used. In the case of synthetic hydrocarbons, their carbon footprint will also depend on the source of CO_2 used in their production (Box 4).

Box 4

Carbon sources for synthetic hydrocarbons and their role in a circular carbon economy

The production of synthetic hydrocarbons involves the combination of hydrogen with a carbon source that is often CO_2, thus enabling a route for carbon recycling within the circular carbon economy framework defined by KAPSARC. If the synthetic hydrocarbon is consumed in a process without CCUS, this CO_2 will be released to the atmosphere. Therefore, the origin of the carbon source is critical in the environmental impact of the synthetic hydrocarbons:

- **CO_2 captured in the combustion of fossil fuels or from industrial processes** producing concentrated CO or CO_2 streams, such as from cement or iron and steel production: in principle, the use of this CO_2 in synthetic hydrocarbons can deliver climate benefits, but it would still involve emissions from fossil fuels. From an energy system's perspective, products derived from fossil or industrial CO_2 can achieve a maximum emissions reduction of 50%. This is because CO_2 can only be avoided once. Either it can reduce the emissions from the fossil or industrial source, or it can reduce the emissions of the final product. It cannot do both. In the long term, only non-fossil CO_2 sources should be used in synthetic hydrocarbons.

- **Direct air capture:** the cost of this alternative remains uncertain since the technology is not available at scale yet, but costs are considerably higher than capture from concentrated sources. The first large-scale plant (1 Mt CO_2/year) is under development in the United States. Theoretically, this alternative can enable 100% carbon recycling.

- **CO_2 captured from bioenergy applications:** The production of biogas and bioethanol gives rise to high-purity CO_2 streams that can be captured at very low cost. In addition, biomass gasification could become a future source of biogenic carbon (as CO or CO_2) if it reaches commercialisation. Theoretically, these routes could also achieve 100% recycling, provided the biomass is produced in a sustainable manner. However, it is uncertain whether sufficient biogenic carbon could be produced sustainably in the future at the scale needed for widespread production of hydrogen-based synthetic hydrocarbon fuels.

B. Opportunities for hydrogen in the context of a circular carbon economy

Hydrogen is intended to play a crosscutting role in a circular carbon economy. Therefore assessing the role of the hydrogen sector as a whole within the concept is a highly complex task due to the innumerable supply chains, which result from the different combinations of production pathways, transport and storage options and the high number of potential applications (direct or using derived products). For this reason, we present here a series of specific examples of hydrogen applications and their potential to reduce or avoid GHG emissions.

Transport

Hydrogen has long been heralded as a potential clean transport fuel since it does not directly emit CO_2 when used in transport applications. However, the carbon reduction potential of hydrogen vehicles should be evaluated on a well-to-wheel (WTW) basis rather than on a tank-to-wheel (TTW) basis. The TTW approach only accounts for CO_2 emissions during the driving period (and so reads zero for battery electric vehicles [BEVs] and FCEVs). In contrast, the WTW approach also considers upstream CO_2 emissions (called well-to-tank [WTT]): in the case of oil, WTT includes CO_2 emissions from oil extraction, refining and transport; for electricity, it accounts for CO_2 emissions from electricity generation, transmission and distribution (including losses), as well as in charging the battery. In the case of hydrogen, the WTT approach accounts for CO_2 emissions from hydrogen production and distribution, and the filling of the hydrogen tank.

The differences in fuel cycle CO_2 performance between internal combustion engines (ICE) vehicles, BEVs and FCEVs vary widely depending on the carbon intensity of the electricity and hydrogen used to power the electric vehicles and fuel cell vehicle, respectively. Figure 10 shows the comparative assessment of the three powertrains for a mid-size car. For FCEVs using hydrogen produced from natural gas without CCUS, CO_2 emissions are about 50% lower compared to ICEs, thanks to the higher fuel economy of FCEVs.

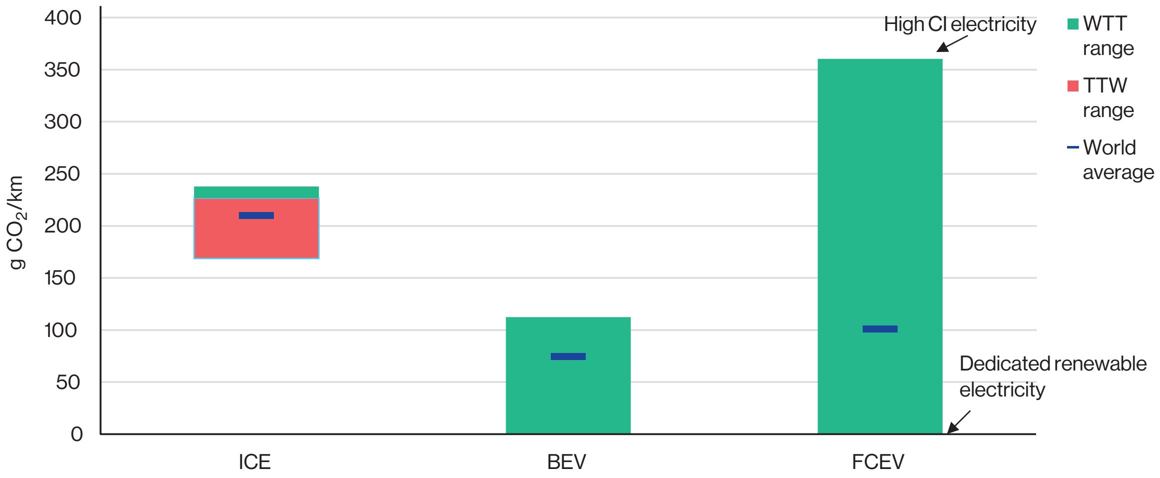

Figure 10. Comparative WTW analysis of a global average mid-size car by powertrain

BEVs show the lowest WTW average carbon intensity. However, both BEVs and FCEVs can reach zero-carbon intensity if dedicated electricity is used for charging or hydrogen production.

Notes: CI = carbon intensity. Comparative well-to-wheel analysis of a global average mid-size car by powertrain across countries. For ICEs, the range is determined considering the minimum and maximum fuel economy values across countries covered by the Global Fuel Economy Initiative (GFEI) (IEA, 2019b). For BEVs, the 2018 carbon intensity (CI) of electricity generation at the country level are based on IEA statistics. The minimum and maximum correspond to a vehicle charging in Iceland and the People's Republic of China, respectively (CI = 0.1 g CO_2/kWh and 605 g CO_2/kWh, respectively). And the world average is based on the global average CI of electricity (CI = 478 g CO_2/kWh) For FCEVs, the minimum corresponds to the production of hydrogen from dedicated renewables, the maximum corresponds to hydrogen production from electrolysis based on the People's Republic of China generation mix, and the world average is based on SMR (8.8 kg CO_2/kg H_2).

Source. IEA (2019b).

A strategy to strengthen the role of hydrogen in the transport sector should consider the simultaneous rollout of FCEVs in light- and heavy-duty vehicles. On one hand, thanks to large volumes of passenger car sales, the deployment of fuel cell passenger cars enables fuel cell costs to fall thanks to economies of scale. On the other hand, the high fuel consumption of heavy-duty vehicles calls for hydrogen delivery costs to be reduced to achieve competitiveness. The adoption of centralised refuelling strategies, such as the "hub-and-spoke" model, could facilitate the uptake of FCEVs in the truck sector by reducing the cost of hydrogen delivery.

The role of hydrogen in the transport sector is not only limited to road transport. It can contribute to the decarbonisation of other transport sectors, like maritime or aviation, where emissions are hard to abate. The shipping sector is at a crossroads, with a growing number of regulations requiring ships to reduce their GHG and pollutant emissions. In such a dynamic regulatory situation that pushes for the adoption of low-carbon fuels, hydrogen-based fuels are likely to play an important role in the maritime sector (Box 5).

In addition, much oil refining and chemical production that currently use hydrogen are already concentrated in coastal industrial zones. The concentration of these large sources of hydrogen demand and supply can create synergies with the use of hydrogen and hydrogen-derived fuels in shipping, thus resulting in lower delivery costs. While further developments are needed for maritime propulsion systems for the adoption of these fuels, existing alternatives to oil-based fuels are either impractical or very costly at present. Strong policy action is needed to force or encourage ship owners and operators to adopt them.

Box 5

Low-carbon ammonia – a means to reduce CO_2 emissions from maritime shipping

Marine transport is a growing source of CO_2 emissions, currently accounting for around 2.2% of global energy-related CO_2 emissions. The IMO has set a target to cut maritime shipping CO_2 emissions by 50% by 2050 relative to 2008 levels, and to reduce the CO_2 emissions per transport work by at least 40% by 2030 and 70% by 2050 compared to 2008.

However, there are only few viable low-carbon fuels for shipping. Current regulations to address GHG emissions from ships are expected to deliver average fleet energy efficiency improvements of around 1.5% annually between 2015 and 2025. Even after design, technical and operational improvements are maximised there will still be a significant emissions gap to meet the IMO's target meaning that marine transport will require the use of low-carbon fuels.

Hydrogen and ammonia are potential alternatives to fossil bunker fuels, offering 85-95% lifecycle CO_2 reduction compared to heavy fuel oil/maritime gas oil if produced from dedicated renewable electricity. Ammonia has advantages over hydrogen in that it has a 50% higher energy density than liquid hydrogen, requiring lower fuel storage volumes. Ammonia has much higher liquefaction temperature than hydrogen, requiring less insulation for storage and thus making its transport easier.

A further consideration is that ammonia today is the most widely traded chemical commodity and the logistical requirements of ammonia transport are known, although widespread use of ammonia as a marine fuel would require significant new infrastructure investment. Liquid hydrogen supply chains and storage infrastructure at ports, meanwhile, are not yet in place. Developments are gathering pace. Ammonia-fuelled shipping initiatives are underway in China, Japan and the Nordic region, while ammonia-fuelled engines are already under development and could be available as early as 2024.

There are several barriers to the uptake of ammonia as a marine fuel. The first is the higher fuel cost relative to fossil bunker fuels and other alternatives such as biofuels. In areas with excellent solar and wind resources, ammonia could be produced for around USD 500/t today, which equates to USD 170/bbl of bunker fuels, potentially falling to 300 USD/t or USD 100/bbl in the longer term. This may represent a 50-120% increase in the total cost of ownership of deep-sea shipping (depending on oil prices), although the impact on the price of many shipped goods is likely to be small. One driver for change could be the willingness of large retail companies to prove to their customers their dedication to reducing their carbon footprints while conserving the benefits of international trade.

Another barrier related to the use of ammonia in shipping that needs careful consideration is its high toxicity, which means that the use of ammonia as a fuel requires professional training. NO_X and N_2O emissions are also a possible factor, with the associated need for exhaust gas treatment. In addition, while favourable compared to hydrogen, ammonia's energy density is less than conventional bunker fuels and its use requires three to four times larger fuel storage, which may reduce payload.

Given the higher cost than conventional fuels, a transition to the use of ammonia as a shipping fuel will require a supportive policy landscape. This includes mechanisms to promote the adoption of low-carbon fuels, such as operational fuel standards. Otherwise investment in production capacity and development of the fuel supply chain and infrastructure will not occur.

Industry

The industrial sector presents one of the greatest challenges in the transition towards a decarbonised future. Heavy industry is a highly competitive and low-margin economic activity where implementing drastic change tends to be a very slow process. Equipment is capital-intensive and long-lived, slowing the pace of deployment of low-carbon technologies. In addition, certain processes use carbon not only as a fuel, but for its chemical properties as well, as in the reduction of iron ore. The process emissions derived from this use of carbon cannot be avoided simply by an energy transition – they need substantially different production processes. Moreover, many of the technological solutions required to decarbonise industrial operations are at the early stages of development.

Hydrogen can become a strong enabler, helping industry navigate these difficulties to achieve significant carbon reductions. The industrial sector is currently the main consumer of hydrogen, and replacing high-carbon hydrogen with low-carbon offers an opportunity for considerable reductions in GHG emissions with relatively low technical risk. Ammonia production is a clear example of this opportunity. The process involves the combination of hydrogen with nitrogen. The largest contributor to its carbon footprint are the direct emissions derived from the use of fossil fuels, with a small contribution from indirect emissions from the production of the electricity used in the process. Implementing CCUS and reaching a capture rate of 95% can reduce the carbon footprint from ammonia production by 75-85%, with the potential to achieve over 90% with future improvement in the efficiency of the process (Figure 11). This means that, of the current direct emissions of 410 Mt CO_2 from ammonia production, 360 Mt could be avoided.[2]

The situation is less clear with the use of electrolytic hydrogen. It avoids direct emissions completely, while the impact on indirect emissions depends on the carbon intensity of the electricity used to power the electrolyser. It has the potential to reduce the carbon intensity further than with CCUS – even to avoid it completely if zero-carbon electricity is used. Electricity with a carbon intensity below 230 g/kWh, currently available just in a few regions of the world, would be needed to reduce the carbon footprint of ammonia to below that from unabated natural gas-based production. Carbon intensity of electricity in the range of 15-35 g/kWh would be needed to reduce the carbon footprint below the production pathway of ammonia from fossil fuels in combination with CCUS.

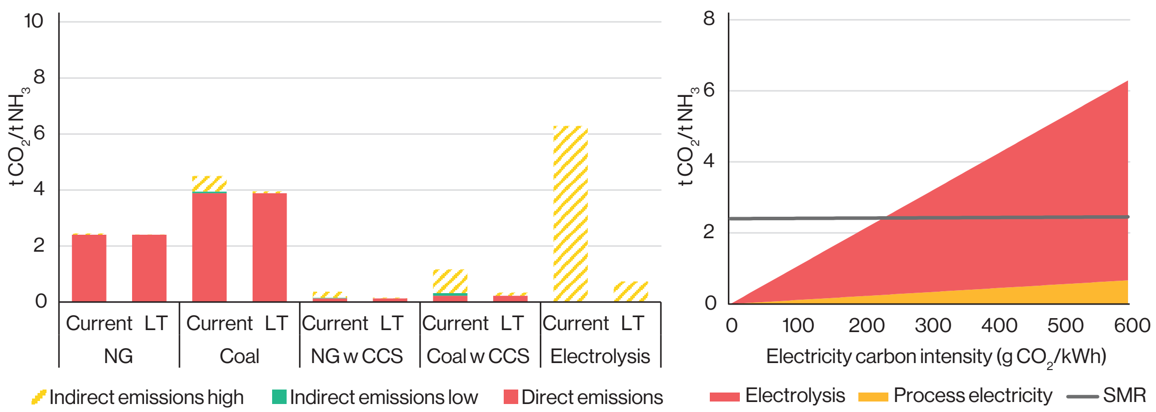

Figure 11. Current and projected carbon intensity of ammonia production pathways and impact of electricity carbon intensity on electrolysis-based ammonia production

CCUS technologies can reduce the carbon intensity of ammonia significantly and the use of electrolytic hydrogen can reduce it even further if very low-carbon electricity is available.

Notes: Assumptions for ammonia production are the same as in the section "Hydrogen supply: current status and outlook". Electricity carbon intensity, low = 0 g CO_2/kWh (current and long term), high = 840 g CO_2/kWh (current) and 70 g CO_2/kWh (long term).

The primary production of steel, which accounts for more than three-quarters of global steel demand today, is another opportunity to reduce CO_2 emissions using hydrogen. The blast furnace-basic oxygen furnace (BF-BOF) route accounts for about 90% of primary steel production globally. The carbon footprint of this route is a result of fossil fuel use during the process (serving the purpose of an energy carrier as well iron ore reducing agent), the use of lime for impurity removal, and indirect emissions from the production of the electricity for the process.

[2] These figures exclude approximately 130 Mt CO_2/yr currently separated and used in urea production. A large proportion of this CO_2 is re-emitted in the agricultural sector when urea is applied to soils.

Additionally, steel production generates "works-arising gases", which are mixtures of gases (including hydrogen and carbon-containing gases). These are used for various purposes on site, such as heat and power generation, but can be also exported for use in other sectors (such as power or methanol production).

An alternative option to the BF-BOF route is the direct reduction of iron-electric arc furnace (DRI-EAF) route, which accounts for about 10% of primary steel production globally. It uses syngas, from SMR or coal gasification, as a reducing agent. This route can reduce the carbon intensity of crude steel production by 35-50% when compared with BF-BOF, depending on the carbon intensity of the electricity used.

The capture of CO_2 from DRI is less technically challenging than DRI modification from syngas to 100% hydrogen, as the exhaust gases produced contain relatively high CO_2 concentrations. The Al Reyadah CCUS project, in the United Arab Emirates, is already operating at commercial scale (CSLF, 2017). This solution can deliver a reduction in CO_2 emissions of 70-95% compared with the BF-BOF route. Further emission reduction via the DRI-EAF route would require the substitution of the syngas with pure hydrogen. However, this is still a technology under demonstration and requires a modified DRI-EAF process design (HYBRIT, 2020). If this technology were demonstrated and low-carbon electrolytic hydrogen was used, the carbon footprint of steel making could drop by more than 99% (it will not reach 100% due to the use of lime in the electric furnace), as shown in Figure 12. The availability of low-carbon electricity is fundamental to ensuring that the DRI-EAF with hydrogen route presents a lower carbon footprint than the DRI-EAF route with CCUS (requiring less than 15 g CO_2/kWh), whereas electricity intensity below 440 g CO_2/kWh will be enough to achieve carbon emissions lower than the BF-BOF route.

Another area where hydrogen can play an important decarbonisation role is high-temperature heat. The Swedish manufacturer Ovako has recently conducted a full-scale trial using hydrogen to heat steel before rolling (Ovako, 2020). The HyNet project is seeking to demonstrate the switch from natural gas to hydrogen in glassmaking and health products manufacture in the United Kingdom (BEIS, 2020). However, most hydrogen-based high-temperature applications still require demonstration.

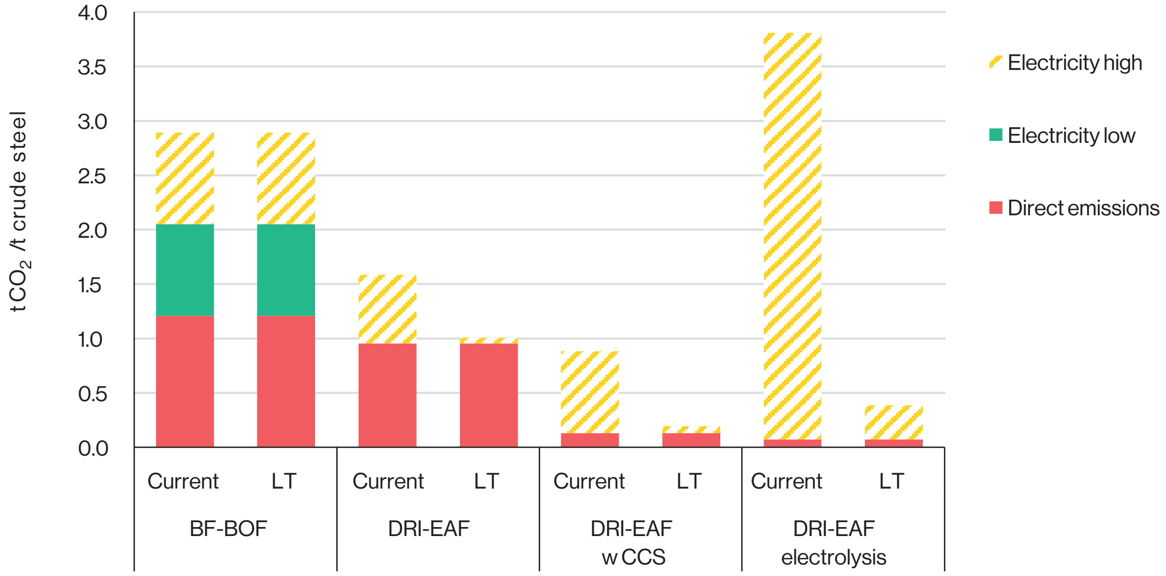

Figure 12. Current and projected carbon intensity of different steel production routes

The use of low-carbon hydrogen in DRI is an attractive option to decrease the carbon footprint of steelmaking. Electrolytic hydrogen could deliver carbon intensities close to zero, but will require very low-carbon electricity.

Notes: Assumptions: BF-BOF, electricity consumption = 0.8 GJ/t crude steel, coal consumption = 20.6 GJ/t crude steel.
DRI-EAF, electricity consumption = 2.7 GJ/t crude steel, natural gas consumption = 11.8 GJ/t crude steel, coal consumption = 2.6 GJ/t crude steel. DRI-EAF with CCS, electricity consumption = 3.2 GJ/t crude steel, coal consumption 0.2 GJ/t = crude steel, natural gas consumption = 11.2 GJ/t crude steel, CO_2 capture rate = 90%.
DRI-EAF electrolysis, electricity consumption = 16.0 GJ/t crude steel, natural gas consumption = 0.3 GJ/t crude steel, coal consumption = 0.4 GJ/t crude steel.
Electricity carbon intensity: low = 0 g CO_2/kWh (current and long term), high = 840 g CO_2/kWh (current) and 70 g CO_2/kWh (long term).

Buildings

Buildings today accounts directly and indirectly for 30% of the final energy consumed around the world. Direct emissions from fossil fuel combustion in buildings for space conditioning and water heating as well as cooking and other service applications amounted to about 3 Gt CO_2. The decarbonisation of heat in buildings is very challenging, needing to take into account several factors including geographical location, building type, existing infrastructure, purchase and operating costs, energy prices and consumer acceptance. Consequently, it appears likely that many different technological options will coexist to meet these various needs.

While the electrification of heat is appropriate for most energy-efficient buildings, low-carbon hydrogen has the potential to supply heat in buildings in certain high-demand areas, replacing natural gas. Hydrogen can be used as a heating fuel by blending it into the existing natural gas network or directly using pure hydrogen. Blending hydrogen into the gas grid is interesting in regions with an extensive gas infrastructure that relies on natural gas for heating, as in the Netherlands, Germany, the United Kingdom, Italy or the United States.

Depending on gas network characteristics, hydrogen could be blended up to 20% on a volumetric basis in distribution grids built with hydrogen-compatible materials, making use of existing infrastructure with minimal or no modification to the grid or domestic end-use equipment (certain industrial users have less tolerance for hydrogen content in the gas). Hydrogen blends higher than 20% would require adaptation of the gas grid and the end-use equipment. Fuelling existing gas boilers with a hydrogen content above 20% leads to drops in efficiency and the risk of failure.

As regards gas grids, there are regions where distribution grids can already transport gas with a high hydrogen content. In Europe, 56% of distribution grids use piping materials compatible with hydrogen (some regions up to 80%). However, a significant mileage of piping still needs to be adapted, for example fitting plastic materials compatible with the use of hydrogen – current steel pipes can suffer from embrittlement when using hydrogen and present larger leakage rates than plastic materials.

Hydrogen can therefore be directly exploited in buildings by using gas/hydrogen blends in boilers, gas heat pumps and fuel cells. The use of natural gas/hydrogen blends in boilers is the easier alternative to implement in the near term. The carbon intensity of the heat produced with these blends in boilers depends on the carbon intensity of the hydrogen used in the mixture, varying from small reductions to significant increases when compared with pure natural gas (Figure 13). Blending 20% hydrogen on a volumetric basis represents around 7% on an energy basis, meaning that with zero-carbon hydrogen, the carbon intensity of heat would decrease by 7%. To put this in context, by 2030 the natural gas demand for domestic heating in the United States is projected at around 160 bcm. Replacing 7% of this demand with zero-carbon hydrogen would avoid the emission from gas boilers of more than 25 Mt CO_2 in 2030, equivalent to around 5 million cars. However, if the hydrogen is not low carbon, as produced by SMR without CCS or electrolysis powered with high-carbon electricity, the carbon intensity of the heat would rise, leading to an increase of 7-90 Mt CO_2 in 2030.

Gas boilers would need to use blended gas with a low-carbon hydrogen content higher than 50% to match the carbon intensity of heat delivered by gas heat pumps. However, that would require major adaptation of gas grids and end-use equipment similar to those needed to use pure hydrogen. Gas heat pumps cannot reach the same efficiency levels as electric heat pumps, but deliver efficiency improvements compared to gas boilers. Moreover, gas heat pumps can also run on blends of hydrogen and natural gas, thus presenting the potential of further decreasing the carbon intensity of the heat delivered. When compared with electric heat pumps, only using renewable hydrogen can match the decarbonisation potential of electric heat pumps.

Another interesting alternative for heat provision using hydrogen is the use of fuel cells. They can be used for the co-generation of electricity and heat, but again the carbon intensity of the heat and electricity produced will depend on the carbon intensity of the hydrogen used in the fuel cell.

In this case, the comparison with alternatives for low-carbon heat is more complex due to the co-generation aspect, since the carbon intensity of heat will also depend on the electricity/heat generation ratio of the fuel cell.

Among this portfolio of technologies, the most cost-effective solution will depend on the type of building and the local and national context. There are situations in which hydrogen can complement the electrification of heat. In particular, the greatest potential can be found where the benefits of adopting hydrogen outweigh its lower efficiency, for example where there is an existing gas network and low-performing buildings that present difficulties for heat pump installation.

In addition, the use hydrogen in buildings could present synergies with the wider energy system, resulting in lower overall system costs than a full electrification alternative. Regions with high variability of temperatures will require large peak capacity on the power generation side, as well as increased energy storage capacity to balance the large intra-day and inter-seasonal differences in heat demand. Some regions present peak heat demand that largely exceeds their current electricity generation capacity. For example, in the United Kingdom the peak heat demand can reach two to three times the current installed power capacity (Watson, Lomas and Buswell, 2019).

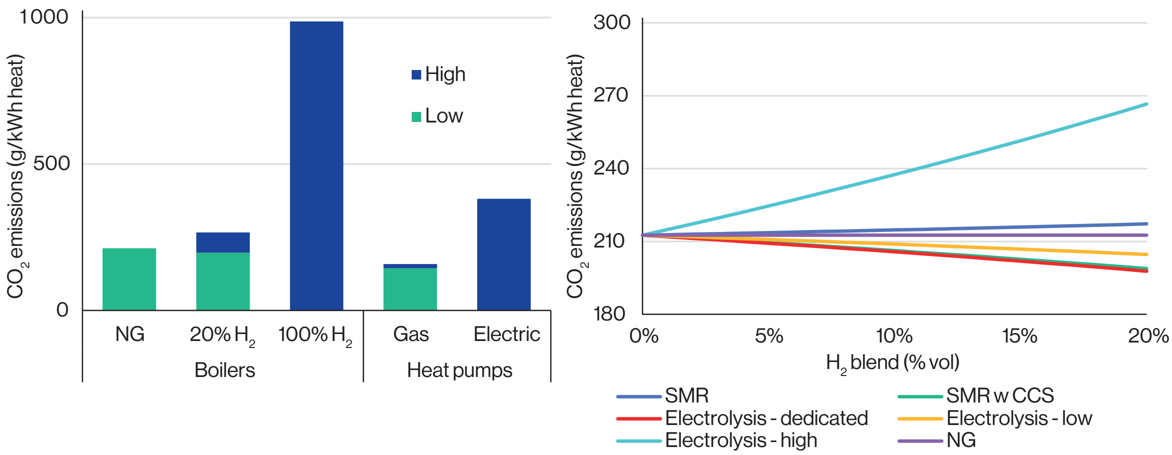

Figure 13. Current carbon intensity of domestic heat technologies and influence of the source of hydrogen on the carbon intensity of natural gas-hydrogen mixtures

Hydrogen from SMR with CCS and electrolysis powered by dedicated renewables can reduce significantly the carbon intensity of heat provision, while hydrogen from high-carbon electricity can increase carbon emissions fivefold.

Notes: Assumptions: boiler efficiency = 95%, gas heat pump coefficient of performance (COP) = 1.27, electric heat pump COP = 2.18-2.81, electricity carbon intensity: low = 0 g CO_2/kWh, high = 840 g CO_2/kWh.

Power

The transition to a decarbonised power system will require increasing shares of variable renewable generation. This can result in important mismatches between supply and demand, with periods of renewable generation surplus and other periods of high demand during low generation availability. During those periods of high demand and low supply, the electricity system will require back-up from flexible generation and/or energy storage.

Currently, peak demand is met mainly by flexible generation using gas turbines. An estimated 700 TWh of electricity are generated annually by gas turbines, which can also provide back-up to electricity systems in periods of low variable renewable generation. This role is expected to grow as the share of renewables keeps increasing. This has important implications for CO_2 emissions, and hydrogen offers an interesting alternative to natural gas-fired turbines. Similar to the case of domestic heating, hydrogen can be mixed or directly used in gas turbines to generate flexible power with lower carbon intensity. In addition, stationary fuel cells can also run on hydrogen to generate power with efficiencies over 60%.

The use of pure hydrogen produced by SMR with CCS in gas turbines can deliver significant carbon reductions against natural gas-fired turbines. If 90% capture rates were achieved, the electricity produced by hydrogen from SMR with CCS would have roughly half the carbon intensity of the electricity produced by natural gas (Figure 14). This would avoid 220 Mt of the 422 Mt CO_2 emitted every year using natural gas to deliver peak load power generation.

In the case of electrolytic hydrogen, delivering lower emissions than those produced by natural gas flexible power generation requires the use of electricity with particularly low carbon intensity to produce hydrogen. This is the consequence of the low roundtrip efficiencies (around 26%) of converting electricity into hydrogen and then using hydrogen to generate electricity again. With current electrolyser efficiencies around 60%, the electricity used in hydrogen production should have a carbon intensity below 130 g CO_2/kWh to match the carbon intensity of natural gas flexible power generation. In the case of using dedicated renewable electricity to produce hydrogen, the flexible power generation could be completely decarbonised. There will be other low-carbon technologies for flexible power generation that can compete with hydrogen, such as biogas-fired engines or gas turbines, hydropower or nuclear energy, although their prevalence will depend on cost and local conditions.

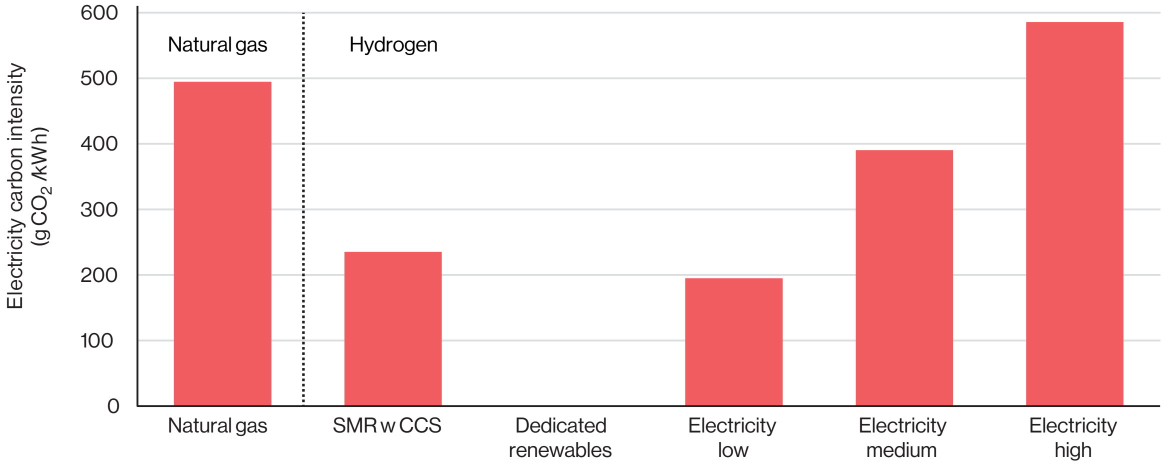

Figure 14. Carbon intensity of flexible power generation with natural gas- and hydrogen-fired turbines

Low-carbon hydrogen can provide back-up to variable renewable generation with a lower carbon intensity than current natural gas-fired turbines.

Notes: Assumptions: gas turbine efficiency = 40%; electrolysis efficiency = 64%. Electricity carbon intensity: low = 50 g CO_2/kWh, medium = 100 g CO_2/kWh, high = 150 g CO_2/kWh.

Hydrogen-derived fuels can also contribute to the decarbonisation of power generation. Ammonia, for example, can be used for co-firing in coal power plants, decreasing the carbon footprint of the electricity generated. This was demonstrated in Japan in 2017 with an ammonia share of up to 1% on an energy basis, and shares of up to 20% have already been demonstrated at 10 MW scale (IEA, 2019a). Considering that by 2030 around 1 250 GW of today's coal power plants could still be in service with a remaining lifetime of at least 20 years, around 1.2 Gt CO_2 per year could be avoided if a 20% blend of ammonia were used. This implies a huge challenge on the supply side since it would require 670 Mt of low-carbon ammonia, which is equivalent to three times current global ammonia production. However, it is also a tremendous investment opportunity for renewable electricity suppliers, close to 3 500 TWh annually.

Hydrogen and hydrogen-derived fuels also present good prospects for long-term and large-scale energy storage. These technologies suffer from low round-trip efficiency when compared with other alternatives like batteries, but batteries are unlikely to be used for long-term and large-scale storage because they suffer from self-discharge and much lower energy densities. Batteries are better suited to short-term energy storage, involving many cycles and short discharge periods, whereas hydrogen and hydrogen-derived fuels are better suited for long-term storage (IEA, 2019a). An appropriate balance in the deployment of both technological alternatives would allow the greater penetration of variable renewable energy.

05

Barriers

The transition from carbon-intensive hydrogen to low-carbon hydrogen as a clean feedstock, and its adoption as a clean fuel, is a very complex endeavour that challenges some of the operating principles of our current energy system. This creates barriers that are preventing the widespread adoption of low-carbon hydrogen both in traditional hydrogen-consuming sectors and in new applications. These barriers need to be identified and addressed to explore the best opportunities to overcome them.

A. Infrastructure

Hydrogen can be used in many sectors, but end users will only switch to hydrogen or hydrogen-based products if it is cost-effective to do so. The final price of hydrogen that users will pay depends on many factors, including the costs of transport and delivery, which in turn depend on the infrastructure. Infrastructure such as pipeline and delivery networks is of particular importance for a new fuel like hydrogen, and in this instance its development is sluggish.

As regards the use of hydrogen in buildings, hydrogen networks are currently limited to a few cases mainly around industrial clusters. Using existing infrastructure could be an alternative to avoid large investment in hydrogen grids until there is greater certainty on the adoption of hydrogen at scale in new applications. However, this option entails its own challenges due to limitations in the hydrogen content allowed in gas grids.

In the case of hydrogen for road transport, a network of refuelling stations is a precondition for widespread deployment of FCEVs, but the current pace of infrastructure development is a brake on adoption. The low utilisation rates currently achieved by hydrogen refuelling stations due to the small number of FCEVs running results in high hydrogen costs, which at the same time discourage users from switching to FCEVs. This is a chicken and egg situation.

New infrastructure is also needed to enable international trade. The first commercial-scale hydrogen export and import infrastructure projects will represent sizeable investments. They may benefit from being structured as public–private partnerships, with some direct public investment and multi-stage competitions to award contracts. In some cases, risks might best be managed by initially funding smaller projects that reassure financiers, although this might well not be effective for infrastructure such as tankers and storage facilities. Subsequent projects should benefit significantly from the exchange of learning and knowledge, insofar as the initial projects are not commercially confidential.

The infrastructure available is also a barrier on the production side. The production of low-carbon hydrogen from fossil fuels equipped with CCS requires CO_2 transport and storage infrastructure, which is currently unavailable and will require time to develop. This is particularly important since fossil technologies equipped with carbon capture are the best way to produce low-carbon hydrogen at scale in the short term. Retrofitting existing hydrogen production plants could be an option to expedite low-carbon hydrogen production where CO_2 storage is available, but this requires the development of the CCS infrastructure.

B. Standards

The harmonisation of standards across regions, and ideally at global level, would help to stimulate project development and cost reductions in the hydrogen supply chain. Standards will be needed across the whole supply chain, in areas as diverse as refuelling nozzles for vehicles, refuelling station permitting, hydrogen supply pressures and safety protocols for hydrogen handling. Both the definition of new standards and the revision of current standards, defined without considering the widespread use of hydrogen as an energy carrier, will be needed. For example, Japanese stakeholders are considering the current safety limitations for the use of hydrogen vehicles and hydrogen distribution on bridges and in tunnels. The United Nations Economic Commission for Europe is currently exploring several of these issues under global technical regulation 13 (UNECE, 2013).

The need for standards will be particularly great for potential hydrogen applications. A clear example is the use of hydrogen to heat buildings. Ensuring the maximum levels of safety is of paramount importance. The development of standards for piping, safety protocols and the installation and operation of end-use appliances (mirroring those for natural gas) can minimise the risks associated with the use of hydrogen for heating. Linked to this is the injection of hydrogen into the natural gas grid. Existing national regulations for hydrogen blending differ between countries, defined by the elements along the gas value chain that are least able to cope with blending. In many countries, blending is limited to 2%, with a few allowing higher shares. These differences are a barrier to international trade as gas blends cannot be used in cross-border pipelines. Without the development of international standards, this issue is unlikely to be resolved.

Ammonia is already transported internationally as a chemical product and the existing standard can be used or adapted. However, in the case of liquid hydrogen transported by ship, there is an interim recommendation but no officially approved standard. To address this issue, the CO_2-free Hydrogen Energy Supply-Chain Technology Research Association is leading a pilot project, shipping liquid hydrogen from Australia to Japan, which will contribute to securing official approval from the IMO for future liquid hydrogen trade (IMO, 2016).

C. Technological uncertainty

Many of the technologies associated with the production and use of hydrogen are emerging and at an early stage of deployment. As for other emerging technologies, it is difficult to ascertain how widely they can be adopted and whether they will be able to reach their whole potential as clean energy solutions. Other once-emerging technologies, like solar PV and wind energy, are now being deployed on a large scale, but had an uncertain future some two decades ago.

Different factors contribute to the uncertainty around hydrogen. Some new applications have yet to be demonstrated. Their future competitiveness depends on factors beyond hydrogen technology alone, including the cost of renewable electricity, grid upgrades and infrastructure availability. Moreover, the impact of the Covid-19 pandemic adds another source of uncertainty about the timescale of demonstration projects and large-scale production (and therefore cost reduction).

These sources of uncertainty are obstacles to evaluating the potential future of hydrogen, meaning that the comparison with other low-carbon technologies could develop in various ways. Contenders include solid-state batteries and pumped-storage hydropower in energy storage; BEVs and biofuels in transport; and the electrification of high-temperature heat. Moreover, it is important to note that if and where such alternatives achieve commercialisation earlier than hydrogen technologies, they will have a head start and capture important market share that could limit the expansion potential of hydrogen in the future.

D. CO_2 emissions accounting and verification

This barrier is strongly linked to the development of standards, although it deserves special attention since the main purpose of adopting low-carbon hydrogen technologies is the decarbonisation of the energy system. Robust methodologies to account for and verify CO_2 emissions are needed to create confidence in the way CO_2 emission reductions are counted and who can claim them.

Those using carbon capture technologies for fossil fuel-based production should strive for high capture rates to ensure that the hydrogen production is low-carbon (for example, in ammonia production partial capture is common practice). Solid and verifiable methodologies to account for carbon emission reductions should be defined so that, if partial capture is used, only the share of hydrogen produced with carbon capture is considered "low-carbon" hydrogen, especially when considering policy support or emission reduction targets.

The issue of life-cycle impacts poses a particular challenge in the case of hydrogen because identical hydrogen molecules can be produced and combined from sources with very different CO_2 intensities. Accounting standards for different sources of hydrogen along the supply chain may be fundamental to creating a market for low-carbon hydrogen and need to be developed on an internationally agreed basis. Some initiatives have already started to address this issue, like the European CertifHy project that has been issuing guarantees of origin since 2019. Further development could usefully extend guarantees of origin to an agreed international standard that certifies the carbon intensity of the delivered gas, accounting for the whole supply chain.

The environmental impact of hydrogen-based synthetic hydrocarbon fuels depends on the CO_2 intensity of both the hydrogen and the CO_2 source used for their production. Policy must therefore account for the CO_2 intensity of the whole value chain to avoid outcomes that do not lead to net CO_2 reductions. For example, policies that incentivise hydrogen production and hydrogen-based fuel production separately could inadvertently result in energy penalties. The policy framework should also clarify which sector can account for the CO_2 abated by hydrogen-based synthetic hydrocarbon. Several stakeholders across the supply chain can feel entitled to claim these reductions, including the industry capturing the CO_2 instead of releasing it, the synthetic fuel producer facing challenges to commercialise the fuel due to its lack of competitiveness against other alternatives, or the end user that will face the additional premium cost of the fuel. In order to prevent conflicts and risks of double or triple counting, a clear scheme is needed to account for and verify CO_2 emissions, one that is internationally recognised and tradable.

E. Other barriers

Other barriers may be perceived as minor issues, but can become major obstacles if they are not anticipated and measures not adopted. Public acceptance is a clear example of an issue that tends to be overlooked and can turn into a major barrier. Hydrogen adoption comes with high upfront infrastructure costs and some existing industrial dynamics. While it entails safety risks that may not differ from those applying to other gaseous fuels, such as natural gas, public perception can be different. It is unclear how citizens will react to these aspects of hydrogen and how they will weigh them against its low-carbon potential and possible importance to a sustainable energy system.

"The Future of Hydrogen" report, published by the IEA for the G20 meeting in 2019, included a geospatial analysis. It identifies the areas with highest renewable potential that could produce electrolytic hydrogen at the lowest cost until the point that it could become competitive with hydrogen produced from fossil fuels. Some of these areas included the Middle East, North Africa and the Mediterranean, and South America. These are also some of the regions presenting the highest water stress across the globe. The development of electrolytic hydrogen production in these areas should be carefully planned alongside water management policies to avoid conflict between water users while protecting ecosystems. The use of seawater desalination could be an option for electrolysis deployment in coastal regions to avoid these impacts.

Another important barrier is the availability of a workforce of skilled professionals to deploy hydrogen technologies at scale and at the pace needed to deliver the ambitious climate targets set by governments and industry. A recent study from the United Kingdom government concluded that converting all current domestic appliances to be hydrogen-ready would require 52 million man-days of effort (Frazer-Nash Consultancy, 2018). This is equivalent to a workforce of 100 000 newly formed hydrogen engineers spending 50% of their working year on conversion over 4 years. This would mean building from scratch a workforce similar to the current 130 000 certified gas engineers working in the United Kingdom. Alternatively, the current workforce of gas engineers could be trained and dedicate around 10% of their working time to conversion activities, requiring 16 years to convert the whole stock of UK appliances. None of these alternatives would be a trivial task – they require planning, developing training programmes and establishing certification schemes. Moreover, it would require strong coordination between many stakeholders across different sectors.

06
Enabling policies

Hydrogen is enjoying unprecedented momentum and many sectors are taking serious steps towards the adoption of hydrogen technologies. However, progress remains slow because most hydrogen technologies are not competitive yet. This is unlikely to change unless there is government intervention to enable cost reductions and speed up the adoption of hydrogen technologies to achieve ambitious sustainable energy targets. Policy measures can efficiently support the development of low-carbon hydrogen technologies:

Set targets and long-term policy signals: Policy makers can adopt public commitments and establish a vision for the role for hydrogen in the short and long term, within their overarching energy, environment and industrial policy frameworks. This should provide stakeholders with confidence that there will be a future marketplace for low-carbon hydrogen and related technologies. Similarly, industrial players can establish their own vision of a role for hydrogen in their sustainability targets. This will create a positive environment for investment and cooperation between industry and government. Policies such as national hydrogen roadmaps and strategies, sectorial and global targets for hydrogen use, economy-wide emissions targets, national industrial strategies and international agreements and commitments can help set this long-term vision for hydrogen. Including measures to track progress can help increase the chances of achieving the policy objectives.

Create hydrogen demand: the successful adoption of hydrogen strongly depends on achieving significant cost savings, which in turn depends on the deployment of hydrogen technologies at scale. Governments need to adopt policies that put an economic value on the use of hydrogen in new uses or from new sources to create growth in hydrogen demand across different applications. Accompanying these policies with international cooperation can help in synchronising the scale-up of hydrogen demand, reducing risks related to competitive pressures on trade-exposed sectors and underpinning investment in manufacturing capacity. Policies like CO_2 pricing, mandates and bans, reverse auctions, tax credits, performance standards, public green procurement rules and gas and electricity market rules can also unlock hydrogen demand. Highly technology-prescriptive policies should be avoided. They should be open to low-carbon hydrogen on equal terms, for example with auctions for low-carbon electricity integrated with power storage.

Address investment risks: many hydrogen applications are entering (or are expected to enter soon) the "valley of death", where demand creation policy is insufficient on its own to make projects bankable or overcome coordination market failures. The successful crossing of this "valley of death" calls for policies that can address risks associated with capital and operational costs such as loans, export credit, risk guarantees, accounting systems that enable trading of "guarantees of origin", tax breaks, regulated returns and water resource and CCUS planning.

Direct research, development and innovation: these will be fundamental in enabling hydrogen to reach its potential since, as they will be a main driver of cost reduction alongside deployment at scale. Governments need to continue playing a central role in setting the research agenda. For early-stage high-risk projects, governments can adopt measures to share risks and attract private capital for innovation. For technologies at the point of market scale-up and presenting lower risk, policy makers can apply a range of tools to incentivise the private sector to take the lead in driving innovation according to market needs and competition. The provision of direct project funding and co-funding, tax incentives, concessionary loans, start-up equity and other traditional R&D policies will be decisive in achieving commercialisation of key technologies.

Remove barriers and define harmonised standards: by doing this, policy makers will facilitate trade, remove risks and ensure safety across the whole hydrogen value chain. Crosscutting issues include agreeing safety standards, avoiding double taxation and meeting distribution purity and pressure. The certification of CO_2 intensity of hydrogen supply can turn into a major barrier if robust methodologies are not defined and agreed. Engaging with local communities and developing information campaigns to address public concerns will ensure that people can make informed decisions about the risks and impacts of new hydrogen.

Policy makers can reinforce the adoption of these policies and their chances of success with international cooperation. International partnerships are vital to foster the growth of versatile, clean hydrogen around the world. Coordinated work between governments to scale up hydrogen, and enable sharing of knowledge and best practices, can help to spur investment in production facilities and infrastructure to bring costs down.

A. Near-term opportunities

The crisis created by the Covid-19 outbreak is overshadowing any near-term scenario for the energy sector, and the situation is no different for hydrogen. The crisis has emerged when many hydrogen initiatives were ramping up, putting their delivery at risk. Governments, industry and other stakeholders are now redefining their priorities and focusing efforts on mitigating the impacts of the crisis. Governments are facing an unprecedented situation in which health is the foremost priority.

However, at the same time they are facing the impact of the crisis on their economies and developing strategies to stimulate them once the pandemic is brought under control and activity can ramp back up. By including hydrogen in these strategies policy makers can contribute to the economic recovery and, at the same time, accelerate the development of clean hydrogen technologies. This would create the foundations for hydrogen to make a meaningful contribution to the clean energy transition in the years ahead.

Governments are focused on immediate job creation and boosting their economies as rapidly as possible. However, it is important to stay farsighted and anticipate future implications of decisions taken now. The last wave of major government stimulus plans, adopted after the 2008 financial crash, has important lessons for selecting the right tools in the fight against the Covid-19 crisis. From an economic viewpoint, the extra spending on clean energy following the 2008 crisis contributed positively to the broader recovery. But from an emissions point of view the recovery from the 2008 financial crisis was energy and carbon intensive, involving the sharpest upswing in carbon emissions in history.

In the current situation, it is clear that energy efficiency and renewable energy will be fundamental to stimulus packages. These industries employ millions of people across their value chains and offer ways to create jobs and revitalise the global economy while driving the energy transition. However, renewables and efficiency alone will not put the world on track to meet climate and sustainability objectives – and other clean energy technologies such as hydrogen will be required, especially in the case of sectors where emissions are hard to abate.

Clean hydrogen and hydrogen-derived fuels could be vital for decarbonising sectors such as shipping, aviation, long-haul trucks, iron and steel production and the chemical industry, where other clean energy technologies cannot be easily deployed. By supporting these technologies, governments can also reap other significant benefits from a wider socioeconomic perspective, such as job creation and healthier industries, to come out of this crisis stronger than before.

In this context, the IEA has reviewed the near-term priorities it identified in 2019 in "The Future of Hydrogen" report to boost hydrogen on the path towards its clean and widespread use (IEA, 2019a). The conclusion: these priorities remain critical opportunities for the efficient adoption of hydrogen as a clean fuel and feedstock. Moreover, in a situation where economic recovery is in the spotlight, they are also opportunities to create near-term economic benefits, robust instruments to mitigate the impacts of the Covid-19 crisis. These are the priorities for policy makers:

1. **Make industrial ports the nerve centres for scaling up the use of clean hydrogen.** A significant proportion of oil refining and chemical production that uses hydrogen from fossil fuels is concentrated in coastal industrial areas. Regions like the North Sea in Europe, the Gulf Coast in North America and the South East of China (which are also among the areas most seriously affected by the Covid-19 outbreak) are industrial hubs that represent significant sources of hydrogen demand. Encouraging hydrogen consumers to shift to cleaner production of hydrogen would drive its cost down. Stimulus packages can boost the development of CCUS infrastructure to enable large-scale production of clean hydrogen close to its largest consumers. Moreover, infrastructure development is a job-intensive activity that can help create positive dynamics in regional job markets.

   These hubs also offer a unique opportunity to deploy water electrolysis at scale if low-cost renewable electricity is available. Using stimulus packages to support electrolyser manufacturing could be especially effective, since it is a known technology that needs mass manufacturing to fully exploit economies of scale and drive its cost down. This would accelerate the adoption of the technology on a significant scale in these large industrial hubs in a relative short time.

   Manufacturing hydrogen equipment, such as electrolysers, is not labour-intensive, but a capital-intensive activity with direct impacts on job creation limited to specialised high-skilled profiles. However, additional jobs could arise indirectly across the whole supply chain and from the development and maintenance of infrastructure related to the deployment of the electrolysers.

   Driving the production of low-carbon hydrogen in industrial ports can also unlock other applications for clean hydrogen, such as fuelling ships and fleets of trucks serving the ports, its use in different machinery or vehicles operating in the ports and powering other nearby industrial facilities like steel plants. These ports can also become the first nods for the development of an international trade network. Inland industrial hubs present a more limited offer of spillovers, but their contribution in the scale-up of clean hydrogen use should not be underestimated.

2. **Build on existing infrastructure.** There are millions of kilometres of natural gas pipeline, and a significant fraction is completely compatible with hydrogen use. Moreover, planning the maintenance and replacement of older pipes with the potential expansion of hydrogen use in mind would significantly expand the compatible network at minimal cost. Introducing clean

hydrogen to replace just 5% of the volume of a country's natural gas supplies would boost the demand for hydrogen and drive down costs.

In the context of economic recovery packages, adopting clean hydrogen mandates for low levels of blending could be a measure to create demand for low-carbon hydrogen. Such policy instruments present synergies with further support measures for manufacturers of low-carbon hydrogen production technologies, such as electrolysers. This could promote the creation of a market for hydrogen, with positive job impacts along the value chain from technology providers to hydrogen producers.

3. **Expand hydrogen in transport through fleets, freight and corridors.** FCEVs can become more competitive if they are focused on replacing high-mileage cars, trucks and buses to carry passengers and goods along popular routes. The use of hydrogen is particularly interesting for these types of vehicles due to their energy and range requirements and patterns of use, which can maximise the use of refuelling infrastructure and thus minimise hydrogen delivery costs.

   This strategy is proving highly efficient in the rapid adoption of hydrogen fuel cell electric buses and trucks in China. Here the business case for intensive medium- and heavy-duty operations has been strengthened by the success in accessing low-cost hydrogen and achieving high utilisation rates at refuelling stations. Stimulus packages present a unique opportunity to develop hydrogen corridors by supporting company fleets to switch to FCEVs, simultaneously deploying hydrogen refuelling stations and auxiliary infrastructure. Such a strategy ensures stable and secure operation of the fleets along the corridor. Developing this infrastructure will result in job creation, as seen in the increase in FCEV manufacturing, especially heavy-duty trucks and buses where several new developers have emerged recently as a consequence of increased demand of FCEVs in these transport sectors.

4. **Promote international shipping routes for hydrogen trade.** The successful growth of the global LNG market has set a precedent for a similar framework for hydrogen trade. International hydrogen trade will take some time to develop, so it needs support now to make an impact on the global energy system. Its development would have significant benefits for the energy market, since it could facilitate access to low-cost hydrogen for certain regions where domestic production is more expensive and it could also contribute to improved energy security. It has the potential of create a significant number of direct jobs through the trade activities themselves, but it can have an even greater and faster impact by generating indirect jobs in creating the infrastructure for the trade routes, and in supporting industries.

B. Hard-to-abate sectors and their link with a circular carbon economy

It is critical to see the big picture to understand the role that hydrogen can play in the transition towards a sustainable future. But it is also important to dedicate efforts to those **hard-to-abate sectors** where hydrogen can make a difference in their decarbonisation, such as industry, aviation and shipping.[3] These are also critical sectors in the context of a circular carbon economy framework, where hydrogen can play an important role and present strong opportunities to interact with other objectives, such as energy efficiency, carbon utilisation and renewables.

The decarbonisation of these sectors is progressing slowly in the face of the cost of low-carbon options, infrastructure needs, the challenge to established supply chains and ingrained habits. The adoption of hydrogen in some of these sectors also depends on the successful demonstration of certain applications, like the full substitution of syngas with hydrogen in steelmaking, or the delivery of substantial cost reductions, as in the case of using synthetic fuels in aviation. These sectors merit special attention and policy makers should accommodate their distinct characteristics to promote their transformation:

1. **Industrial sector.** The decarbonisation of the industrial sector is one of the greatest challenges in the transition to a sustainable energy system, and hydrogen offers a route to meaningfully reduce emissions. In the chemical sector, replacing the current high-carbon hydrogen with low-carbon is an option with low-technical risk. In the steel sector, DRI is the faster-growing production route and projects are under development to demonstrate the use of 100% hydrogen as a reductant, instead of synthesis gas.

   In addition, low-carbon hydrogen has the potential to help decarbonise the more geographically fragmented portions of industrial high-temperature heat demand where direct application of CCUS may prove impractical. Adopting policies such as carbon pricing, labelling standards and green procurement can facilitate the uptake of low-carbon hydrogen in these processes. Support for continuous innovation and demonstration will be crucial to lower costs and improve the competitiveness of technologies that are not commercial yet, but which will be needed to achieve progress in the decarbonisation of the industrial sector in years ahead.

[3] The recently published IEA report “Energy Technology Perspectives 2020” focusses on the technology and innovation needs of selected hard-to-abate sectors.

2. Shipping. Ships have high per-kilometre energy intensity and large power needs, resulting in demanding fuel requirements. A switch to low-carbon fuels seems unlikely to occur in the absence of policy, whether mandates, direct carbon pricing, and/or more flexible and potentially more palatable measures such as low-carbon fuel standards. Supporting programmes to develop systems to fuel shipping with ammonia would be an alternative to accelerate the adoption of hydrogen-derived fuels, and drive decarbonisation of the sector.

3. Aviation. The use of pure hydrogen as an aviation fuel requires significant further R&D. Hydrogen's low energy density and the need for cryogenic storage would require changes to aircraft design, as well as new refuelling and storage infrastructure at airports. In contrast, hydrogen-based liquid fuels would require no changes to design or refuelling infrastructure at airports. Synthetic fuels based on electrolytic hydrogen are currently more expensive than conventional jet fuel. Fuel represents a large share of the total costs of operating aircraft, so this would significantly increase operating costs. Policy support in the form of low-carbon targets or other approaches is critical to enable the adoption of these hydrogen-derived fuels.

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