The Future of Hydrogen

Seizing today's opportunities

Report prepared by the IEA
for the G20, Japan

June
2019

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Foreword

This is a critical year for hydrogen. It is enjoying unprecedented momentum around the world and could finally be set on a path to fulfil its longstanding potential as a clean energy solution.

To seize this opportunity, governments and companies need to be taking ambitious and real-world actions now. We are very grateful to the government of Japan for its request under its presidency of the G20 that the International Energy Agency (IEA) prepare this important and timely report.

Our study provides an extensive and independent assessment of hydrogen that lays out where things stand now; the ways in which hydrogen can help to achieve a clean, secure and affordable energy future; and how we can go about realising its potential. To help to get things moving, we have identified the most promising immediate opportunities to provide a springboard for the future.

As the world's leading energy authority covering all fuels and all technologies, the IEA is ideally placed to help to shape global policy on hydrogen. The rigorous analysis in this report was conducted in close collaboration with governments, industry and academia.

This study on hydrogen is part of a comprehensive approach the IEA is taking to the global energy system. Last month, we published a report on the role of nuclear power in a clean energy system. We are also holding various high-level meetings to underscore the critical elements needed for a sustainable energy future – including a ministerial conference in Dublin this month on energy efficiency and another ministerial on systems integration of renewables in Berlin in October 2019.

I very much hope our report on hydrogen will inform discussions and decisions among G20 countries, as well as those among other governments and companies across the world. I hope it will help to translate hydrogen's current momentum into real-world action that sets hydrogen firmly on the path to becoming a significant enabler of a clean, secure and affordable energy future.

Beyond this report, the IEA will remain focused on hydrogen, further expanding our expertise in order to monitor progress and provide guidance on technologies, policies and market design.

We will continue to work closely with governments and all other stakeholders to support your efforts to make the most out of hydrogen's huge potential.

The IEA looks forward to continuing this journey together.

Dr. Fatih Birol
Executive Director
International Energy Agency

Acknowledgements

This study was prepared by a cross-agency hydrogen working group drawn from all relevant directorates and offices of the IEA. The study was designed and directed by Timur Gül (Head of the Energy Technology Policy Division) and Dave Turk (Head of the Strategic Initiatives Office). The analysis and production of the report was co-ordinated by Simon Bennett and Uwe Remme.

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Edmund Hosker carried editorial responsibility. Justin French-Brooks was the copy-editor.

The report benefited from valuable inputs, comments and feedback from other experts within the IEA, including Paul Simons, Mechthild Wörsdörfer, Laura Cozzi, Laszlo Varro, Paolo Frankl, Peter Fraser, Tim Gould and Julian Prime. Thanks also go to Tom Allen-Olivar, Jon Custer, Astrid Dumond, Christopher Gully, Jad Mouawad, Isabelle Nonain-Semelin, Robert Stone and Therese Walsh of the IEA Communication and Digital Office for their help in producing the report.

The work could not have been achieved without the support provided by: the Japanese Ministry of Economy, Trade and Industry; the Netherlands Ministry of Economic Affairs and Climate Policy; and the New Zealand Ministry of Business, Innovation and Employment.

We are particularly indebted to the expertise and guidance of the High-Level Advisory Panel for this report, chaired by Noé van Hulst (Hydrogen Envoy, Ministry of Economic Affairs & Climate Policy, Netherlands). Members include The Honourable Elisabeth Köstinger (Minister of Sustainability and Tourism, Austria), Ahmad O. Al-Khowaiter, Chief Technology Officer, Saudi Aramco), Dr. Alan Finkel (Australia’s Chief Scientist, Office of the Chief Scientist), Mikio Kizaki (Chief Professional Engineer, Toyota Motor Corporation, Japan), Dr. Rebecca Maserumule (Chief Director of Hydrogen and Energy, Department of Science and Technology, South Africa), Dr. Ajay Mathur (Director General, The Energy and Resources Institute, India), Dominique Ristori (Director General Energy, European Commission), Dr. Sunita Satyapal (Director Fuel Cell Technologies Office, US Department of Energy, United States) and Dr. Adnan Shihab-Eldin (Director General of the Kuwait Foundation for the Advancement of Sciences, Kuwait).

We appreciate the contributions of speakers and participants at the IEA High-Level Workhop on Hydrogen held in February 2019.

Many experts from outside the IEA provided input, commented on the underlying analytical work and reviewed the report. Their comments and suggestions were of great value. They include:

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Everett Anderson	NEL Hydrogen
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Bart Birbuyck	FCH-JU
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Klaus Bonhoff	NOW
Valérie Bouillon-Delporte	Michelin
Chris Bronsdon	Eneus Energy
Tyler Bryant	Fortis BC
Karl Buttiens	Arcelormittal
Jorgo Chatzimarkakis	Hydrogen Europe
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Table of contents

List of figures

List of boxes

List of tables

Executive summary

The time is right to tap into hydrogen's potential to play a key role in a clean, secure and affordable energy future. At the request of the government of Japan under its G20 presidency, the International Energy Agency (IEA) has produced this landmark report to analyse the current state of play for hydrogen and to offer guidance on its future development. The report finds that clean hydrogen is currently enjoying unprecedented political and business momentum, with the number of policies and projects around the world expanding rapidly. It concludes that now is the time to scale up technologies and bring down costs to allow hydrogen to become widely used. The pragmatic and actionable recommendations to governments and industry that are provided will make it possible to take full advantage of this increasing momentum.

Hydrogen can help tackle various critical energy challenges. It offers ways to decarbonise a range of sectors – including long-haul transport, chemicals, and iron and steel – where it is proving difficult to meaningfully reduce emissions. It can also help improve air quality and strengthen energy security. Despite very ambitious international climate goals, global energy-related CO_2 emissions reached an all time high in 2018. Outdoor air pollution also remains a pressing problem, with around 3 million people dying prematurely each year.

Hydrogen is versatile. Technologies already available today enable hydrogen to produce, store, move and use energy in different ways. A wide variety of fuels are able to produce hydrogen, including renewables, nuclear, natural gas, coal and oil. It can be transported as a gas by pipelines or in liquid form by ships, much like liquefied natural gas (LNG). It can be transformed into electricity and methane to power homes and feed industry, and into fuels for cars, trucks, ships and planes.

Hydrogen can enable renewables to provide an even greater contribution. It has the potential to help with variable output from renewables, like solar photovoltaics (PV) and wind, whose availability is not always well matched with demand. Hydrogen is one of the leading options for storing energy from renewables and looks promising to be a lowest-cost option for storing electricity over days, weeks or even months. Hydrogen and hydrogen-based fuels can transport energy from renewables over long distances – from regions with abundant solar and wind resources, such as Australia or Latin America, to energy-hungry cities thousands of kilometres away.

There have been false starts for hydrogen in the past; this time could be different. The recent successes of solar PV, wind, batteries and electric vehicles have shown that policy and technology innovation have the power to build global clean energy industries. With a global energy sector in flux, the versatility of hydrogen is attracting stronger interest from a diverse group of governments and companies. Support is coming from governments that both import and export energy as well as renewable electricity suppliers, industrial gas producers, electricity and gas utilities, automakers, oil and gas companies, major engineering firms, and cities. Investments in hydrogen can help foster new technological and industrial development in economies around the world, creating skilled jobs.

Hydrogen can be used much more widely. Today, hydrogen is used mostly in oil refining and for the production of fertilisers. For it to make a significant contribution to clean energy transitions, it also needs to be adopted in sectors where it is almost completely absent at the moment, such as transport, buildings and power generation.

However, clean, widespread use of hydrogen in global energy transitions faces several challenges:

- **Producing hydrogen from low-carbon energy is costly at the moment**. IEA analysis finds that the cost of producing hydrogen from renewable electricity could fall 30% by 2030 as a result of declining costs of renewables and the scaling up of hydrogen production. Fuel cells, refuelling equipment and electrolysers (which produce hydrogen from electricity and water) can all benefit from mass manufacturing.

- **The development of hydrogen infrastructure is slow and holding back widespread adoption.** Hydrogen prices for consumers are highly dependent on how many refuelling stations there are, how often they are used and how much hydrogen is delivered per day. Tackling this is likely to require planning and coordination that brings together national and local governments, industry and investors.

- **Hydrogen is almost entirely supplied from natural gas and coal today.** Hydrogen is already with us at industrial scale all around the world, but its production is responsible for annual CO_2 emissions equivalent to those of Indonesia and the United Kingdom combined. Harnessing this existing scale on the way to a clean energy future requires both the capture of CO_2 from hydrogen production from fossil fuels and greater supplies of hydrogen from clean electricity.

- **Regulations currently limit the development of a clean hydrogen industry.** Government and industry must work together to ensure existing regulations are not an unnecessary barrier to investment. Trade will benefit from common international standards for the safety of transporting and storing large volumes of hydrogen and for tracing the environmental impacts of different hydrogen supplies.

The IEA has identified four near-term opportunities to boost hydrogen on the path towards its clean, widespread use. Focusing on these real-world springboards could help hydrogen achieve the necessary scale to bring down costs and reduce risks for governments and the private sector. While each opportunity has a distinct purpose, all four also mutually reinforce one another.

1. **Make industrial ports the nerve centres for scaling up the use of clean hydrogen.** Today, much of the refining and chemicals production that uses hydrogen based on fossil fuels is already concentrated in coastal industrial zones around the world, such as the North Sea in Europe, the Gulf Coast in North America and southeastern China. Encouraging these plants to shift to cleaner hydrogen production would drive down overall costs. These large sources of hydrogen supply can also fuel ships and trucks serving the ports and power other nearby industrial facilities like steel plants.

2. **Build on existing infrastructure, such as millions of kilometres of natural gas pipelines.** Introducing clean hydrogen to replace just 5% of the volume of countries' natural gas supplies would significantly boost demand for hydrogen and drive down costs.

3. **Expand hydrogen in transport through fleets, freight and corridors.** Powering high-mileage cars, trucks and buses to carry passengers and goods along popular routes can make fuel-cell vehicles more competitive.

4. **Launch the hydrogen trade's first international shipping routes.** Lessons from the successful growth of the global LNG market can be leveraged. International hydrogen trade needs to start soon if it is to make an impact on the global energy system.

International co-operation is vital to accelerate the growth of versatile, clean hydrogen around the world. If governments work to scale up hydrogen in a co-ordinated way, it can help to spur investments in factories and infrastructure that will bring down costs and enable the sharing of knowledge and best practices. Trade in hydrogen will benefit from common international standards. As the global energy organisation that covers all fuels and all technologies, the IEA will continue to provide rigorous analysis and policy advice to support international co-operation and to conduct effective tracking of progress in the years ahead.

As a roadmap for the future, we are offering seven key recommendations to help governments, companies and others to seize this chance to enable clean hydrogen to fulfil its long-term potential.

The IEA's 7 key recommendations to scale up hydrogen

1. **Establish a role for hydrogen in long-term energy strategies.** National, regional and city governments can guide future expectations. Companies should also have clear long-term goals. Key sectors include refining, chemicals, iron and steel, freight and long-distance transport, buildings, and power generation and storage.

2. **Stimulate commercial demand for clean hydrogen.** Clean hydrogen technologies are available but costs remain challenging. Policies that create sustainable markets for clean hydrogen, especially to reduce emissions from fossil fuel-based hydrogen, are needed to underpin investments by suppliers, distributors and users. By scaling up supply chains, these investments can drive cost reductions, whether from low-carbon electricity or fossil fuels with carbon capture, utilisation and storage.

3. **Address investment risks of first-movers.** New applications for hydrogen, as well as clean hydrogen supply and infrastructure projects, stand at the riskiest point of the deployment curve. Targeted and time-limited loans, guarantees and other tools can help the private sector to invest, learn and share risks and rewards.

4. **Support R&D to bring down costs.** Alongside cost reductions from economies of scale, R&D is crucial to lower costs and improve performance, including for fuel cells, hydrogen-based fuels and electrolysers (the technology that produces hydrogen from water). Government actions, including use of public funds, are critical in setting the research agenda, taking risks and attracting private capital for innovation.

5. **Eliminate unnecessary regulatory barriers and harmonise standards.** Project developers face hurdles where regulations and permit requirements are unclear, unfit for new purposes, or inconsistent across sectors and countries. Sharing knowledge and harmonising standards is key, including for equipment, safety and certifying emissions from different sources. Hydrogen's complex supply chains mean governments, companies, communities and civil society need to consult regularly.

6. **Engage internationally and track progress.** Enhanced international co-operation is needed across the board but especially on standards, sharing of good practices and cross-border infrastructure. Hydrogen production and use need to be monitored and reported on a regular basis to keep track of progress towards long-term goals.

7. **Focus on four key opportunities to further increase momentum over the next decade.** By building on current policies, infrastructure and skills, these mutually supportive opportunities can help to scale up infrastructure development, enhance investor confidence and lower costs:

   - Make the most of existing industrial ports to turn them into hubs for lower-cost, lower-carbon hydrogen.
   - Use existing gas infrastructure to spur new clean hydrogen supplies.
   - Support transport fleets, freight and corridors to make fuel-cell vehicles more competitive.
   - Establish the first shipping routes to kick-start the international hydrogen trade.

Chapter 1: Introduction

Hydrogen and energy have a long shared history. The first demonstrations of water electrolysis and fuel cells captured the imagination of engineers in the 1800s. Hydrogen was used to fuel the first internal combustion engines over 200 years ago. Hydrogen provided lift to balloons and airships in the 18th and 19th centuries, and propelled humanity to the moon in the 1960s. Hydrogen in ammonia fertiliser (from fossil fuels and, earlier, from electricity and water) has helped feed a growing global population. And hydrogen has been an integral part of the energy industry since the mid-20th century, when its use became commonplace in oil refining.

Supplying hydrogen to industrial users is now a major business globally. Demand for hydrogen, which has grown more than threefold since 1975, continues to rise (Figure 1). Demand for hydrogen in its pure form is around 70 million tonnes per year (MtH_2/yr). This hydrogen is almost entirely supplied from fossil fuels, with 6% of global natural gas and 2% of global coal going to hydrogen production.[1] As a consequence, production of hydrogen is responsible for carbon dioxide (CO_2) emissions of around 830 million tonnes of carbon dioxide per year ($MtCO_2$/yr), equivalent to the CO_2 emissions of Indonesia and the United Kingdom combined. In energy terms, total annual hydrogen demand worldwide is around 330 million tonnes of oil equivalent (Mtoe), larger than the primary energy supply of Germany.

These existing markets for hydrogen build on its attributes: it is light, storable, reactive, has high energy content per unit mass, and can be readily produced at industrial scale. Today's growing interest in the widespread use of hydrogen for clean energy systems rests largely on two additional attributes: 1) hydrogen can be used without direct emissions of air pollutants or greenhouse gases; and 2) it can be made from a diverse range of low-carbon energy sources. Its potential supply includes production from renewable electricity, biomass and nuclear. Low-carbon production from fossil fuels is also possible, if combined with carbon capture, use and storage (CCUS)[2] and emissions during fossil fuel extraction and supply are mitigated.

Broadly speaking, hydrogen can contribute to a resilient, sustainable energy future in two ways:

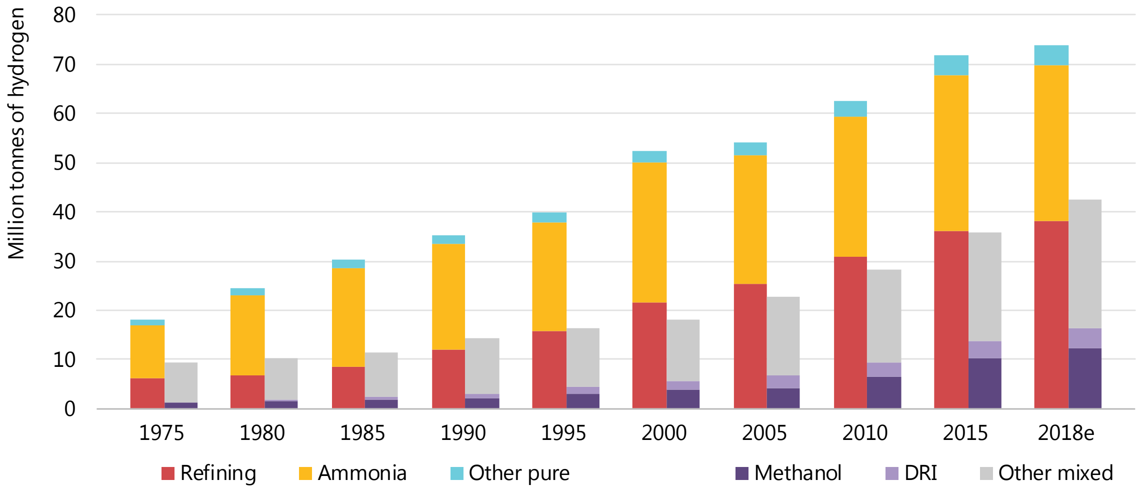
1. Existing applications of hydrogen can use hydrogen produced using alternative, cleaner production methods, and from a more diverse set of energy sources.
2. Hydrogen can be used in a wide range of new applications as an alternative to current fuels and inputs, or as a complement to the greater use of electricity in these applications. In these cases – for example in transport, heating, steel production and electricity – hydrogen can be used in its pure form, or converted to hydrogen-based fuels, including synthetic methane, synthetic liquid fuels, ammonia and methanol.

[1] A further 45 MtH_2/yr are used in industries such as steel and methanol production without prior separation of the hydrogen from other gases.

[2] The term CCUS is used neutrally throughout this report to refer to the capture of CO_2 (before it can be emitted or directly from the air), followed by permanent geological storage or uses of CO_2 that deliver equivalent emissions reductions – for example through chemical integration into long-lasting materials. This report also covers the use of captured CO_2 as an input to hydrogen-based fuels and feedstocks, which is a form of CCUS with emissions reduction benefits that vary widely with the source of carbon and its final use and are generally not equivalent to geological storage of the CO_2.

In both ways, hydrogen has the potential to reinforce and connect different parts of the energy system. By producing hydrogen, renewable electricity can be used in applications that are better served by chemical fuels. Low-carbon energy can be supplied over very long distances, and electricity can be stored to meet weekly or monthly imbalances in supply and demand.

Figure 1. Global annual demand for hydrogen since 1975



Notes: DRI = direct reduced iron steel production. Refining, ammonia and "other pure" represent demand for specific applications that require hydrogen with only small levels of additives or contaminants tolerated. Methanol, DRI and "other mixed" represent demand for applications that use hydrogen as part of a mixture of gases, such as synthesis gas, for fuel or feedstock.

Source: IEA 2019. All rights reserved.

Around 70 MtH_2/yr is used today in pure form, mostly for oil refining and ammonia manufacture for fertilisers; a further 45 MtH_2 is used in industry without prior separation from other gases.

2019: A moment of unprecedented momentum for hydrogen

Interest in hydrogen's potential as a widespread, low-carbon energy carrier is not new. Over recent decades a wide range of experts has researched the potential for producing hydrogen from diverse sources, transporting and storing it, and using it to provide final energy services without emissions. The two previous major cycles of enthusiasm for hydrogen focused largely on the use of fuel cells in the transport sector (Box 1). What is new today is both the breadth of possibilities for hydrogen use being discussed and the depth of political enthusiasm for those possibilities around the world. Hydrogen is increasingly a staple of mainstream energy conversations in almost all regions, with a diverse group of countries and companies all seeing hydrogen as having a potentially valuable and wide-ranging part to play in the future of energy.

Box 1. Previous waves of enthusiasm for hydrogen

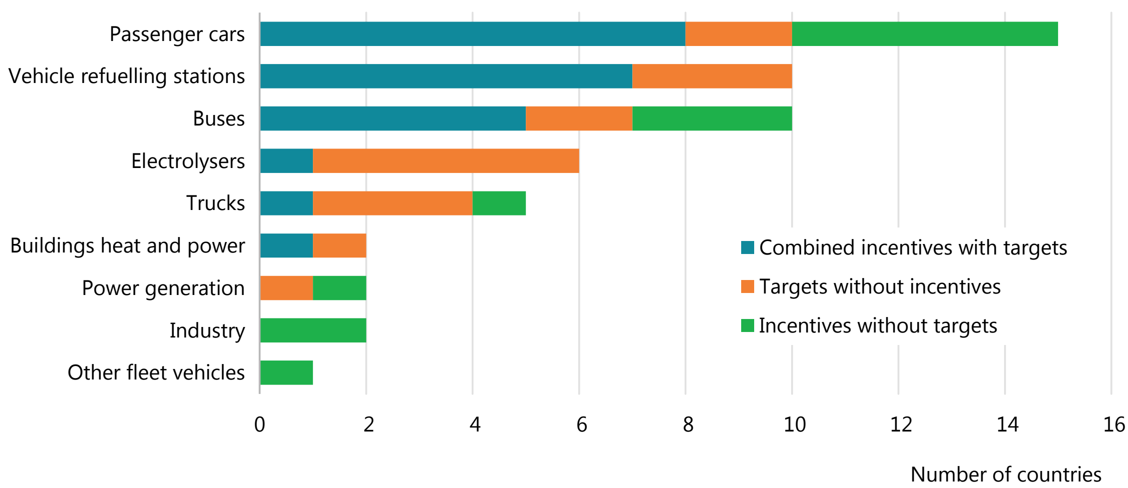
Hydrogen has seen several waves of interest in recent history, none of which fully translated into rising, sustainable investment. A brief summary of these earlier periods indicates that this may have been because hydrogen scale-up was highly dependent on high and rising prices for oil and gas, and was focused to a considerable extent on a single end-use sector: transport.

- Interest in hydrogen rose during the 1970s with oil price shocks, petroleum shortages and attention to air pollution and acid rain. Projections indicated that, in the long term, hydrogen produced from coal or nuclear electricity could have an important role to play in providing energy, particularly for transport. The International Journal of Hydrogen Energy was launched in 1976, and the International Energy Agency (IEA) Hydrogen and Fuel Cell Technology Collaboration Programme was established in 1977. Interest in the potential of hydrogen waned as oil and gas resources proved plentiful, oil prices moderated, nuclear power faced increasing public resistance, and other control measures addressed air pollution problems.
- In the 1990s concern about climate change spurred more studies on hydrogen, with a particular focus on carbon capture and storage (CCS), renewable energy and transport. In 1993 Japan announced funding of JPY 4.5 billion for the first four years of its long-term WE-NET programme for international hydrogen trade based on renewable energy. The European Commission and the Government of Quebec allocated around CAD 33 million to explore together a range of hydrogen storage and use cases, including international hydrogen shipments. Many major automakers unveiled hydrogen cars at motor shows in the 1990s on the back of rapid progress in fuel cell technology. But oil prices remained low through the second half of the decade, stifling support that could have moved these projects closer to the mainstream.
- By the early 2000s concern about climate change had begun to translate into renewed policy action aimed at the transport sector, and concerns about peak oil resurfaced. Although nuclear was not universally favoured, hopes for a new generation of cheaper nuclear plants and the thermal splitting of water were central to many low estimates of hydrogen costs. The United States convened the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) in 2003. Wider deployment of hydrogen-powered vehicles was frustrated in part by the "chicken and egg" problem of needing to develop infrastructure and vehicles in tandem. By 2010, expectations for hydrogen dipped with the retreat of the peak oil narrative, uncertainty about the strength of climate policy developments and progress with battery electric vehicles, which have less expensive initial infrastructure needs than hydrogen vehicles.

Today's coalition of voices in favour of hydrogen includes renewable electricity suppliers, industrial gas producers, electricity and gas utilities, automakers, oil and gas companies, major engineering firms and the governments of most of the world's largest economies. It also includes those who use, or could use, hydrogen as a feedstock for industrial production, not just energy. In 2017 the Hydrogen Council was formed to bring together relevant private-sector players. Its steering group now has 33 members at CEO and chairperson level and 21 supporting members. The possibility that these influential stakeholders will work together to ensure that projects are implemented and markets are developed is an important indication that hydrogen may now command the kind of committed cross-sectoral support it needs for the future.

The number of countries with polices that directly support investment in hydrogen technologies is increasing, along with the number of sectors they target. By mid-2019 the total number of targets, mandates and policy incentives in place globally to directly support hydrogen was around 50 (Figure 2). Those that are sector-specific cover six main areas, with transport being by far the largest. Among the Group of Twenty (G20) and the European Union, 11 have such policies in place and 9 have national roadmaps for hydrogen energy. In the past year alone, many governments made notable hydrogen-related announcements (Table 1). Over the past few years, global spending on hydrogen energy research, development and demonstration (RD&D) by national governments has risen, although it remains lower than the 2008 peak (Figure 3).

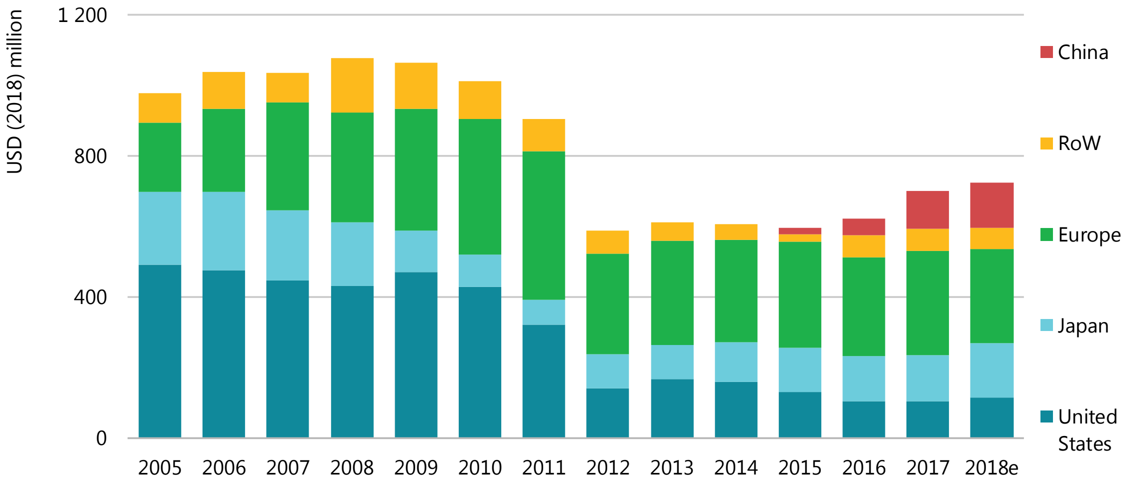
Figure 2. Policies directly supporting hydrogen deployment by target application



Note: Based on available data up to May 2019.

Source: IEA analysis and government surveys in collaboration with IEA Hydrogen Technology Collaboration Programme; IPHE (2019), *Country Updates*.

Figure 3. Government RD&D budgets for hydrogen and fuel cells



Notes: Government spending includes European Commission funding, but does not include sub-national funding, which can be significant in some countries. 2018e = estimated; RoW = rest of world.

Source: IEA (2018a), *RD&D Statistics*.

Table 1. Selected hydrogen-related government announcements since early 2018

Country	Announcements and developments since early 2018
Australia	Announced more than AUD 100 million to support hydrogen research and pilot projects. Published a technical roadmap for hydrogen in Australia produced by the Commonwealth Scientific and Industrial Research Organisation (CSIRO). Has set up a government working group to develop a national hydrogen strategy for completion by the end of 2019.
Austria	Announced that a hydrogen strategy based on renewable electricity would be developed in 2019 as part of the Austrian Climate and Energy Strategy for 2030.
Belgium	Published a government-approved hydrogen roadmap in 2018, with specific targets set for 2030 and 2050 and an associated EUR 50 million regional investment plan for power-to-gas.
Brazil	Included hydrogen in the Science, Technology and Innovation Plan for Renewables and Biofuels. Hosted and supported the 22nd World Hydrogen Energy Conference in 2018.
China	Announced that the Ten Cities programme that launched battery electric vehicles in the People's Republic of China ("China") would be replicated for hydrogen transport in Beijing, Shanghai and Chengdu, among others. Announced that Wuhan will become the first Chinese Hydrogen City, with up to 100 fuel cell automakers and related enterprises and up to 300 filling stations by 2025. Announced targets of 5 000 fuel cell electric vehicles (FCEVs) by 2020 and recommitted to the 2015 target of 1 million FCEVs by 2030, plus 1 000 refuelling stations. Exempted FCEVs (and battery electric vehicles) from vehicle and vessel tax.
European Union	The European Commission published a long-term decarbonisation strategy that included hydrogen pathways for achieving carbon neutrality; recast the directive on the promotion of the use of energy from renewable sources, enabling hydrogen produced from renewable sources with guarantees of origin to be counted against 2030 renewables targets; and set up a "Hydrogen Energy Network" as a platform for discussion of hydrogen among EU member states. Twenty-eight European countries signed the Linz Declaration "Hydrogen Initiative" promoting co-operation on sustainable hydrogen technology, alongside around 100 businesses, organisations and institutions.
France	Unveiled a Hydrogen Deployment Plan and EUR 100 million funding and 2023 and 2028 targets for low-carbon hydrogen in industry, transport and for renewable energy storage, including for islands.
Germany	Approved the National Innovation Programme for Hydrogen and Fuel Cell Technologies for another ten years with EUR 1.4 billion of funding, including subsidies for publicly accessible hydrogen refuelling stations, fuel cell vehicles and micro co-generation purchases, to be complemented by EUR 2 billion of private investment. Supported the first commercial operation of a hydrogen-powered train, and the largest annual increase in refuelling stations in the country, though the H2mobility programme.
India	The Supreme Court asked Delhi to explore use of fuel cell buses in the city to counter air pollution, and the government published an INR 60 million call for research proposals on hydrogen and fuel cells.
Italy	Issued regulations to overcome barriers to the deployment of hydrogen refuelling stations by raising the allowable pressure for hydrogen distribution and enhancing safety, economic and social aspects.

Country	Announcements and developments since early 2018
Japan	Hosted the first Hydrogen Energy Ministerial Meeting of representatives from 21 countries, plus companies, resulting in a joint Tokyo Statement on international co-ordination. Updated its Strategic Roadmap to implement the Basic Hydrogen Strategy, including new targets for hydrogen and fuel cell costs and deployment, and firing hydrogen carriers in power plants. The Development Bank of Japan joined a consortium of companies to launch Japan H2 Mobility with a target to build 80 hydrogen refuelling stations by 2021 under the guidance of the Japanese central government's Ministerial Council on Renewable Energy, Hydrogen and Related Issues. The Cross-Ministerial Strategic Innovation Promotion Program (SIP) Energy Carriers initiative concluded its 2014–18 work programme and a Green Ammonia Consortium was launched to help support the next phase.
Korea	Published a hydrogen economy roadmap with 2022 and 2040 targets for buses, FCEVs and refuelling stations, and expressed a vision to shift all commercial vehicles to hydrogen by 2025. Provided financial support for refuelling stations and eased permitting. Announced that it would work on a technological roadmap for the hydrogen economy.
The Netherlands	Published a hydrogen roadmap and included a chapter on hydrogen in the Dutch Climate Agreement. Spearheaded the first meetings of the Pentalateral Energy Forum of Belgium, the Netherlands, Luxembourg, France, Germany and Austria in support of cooperation on hydrogen in north-west Europe.
New Zealand	Signed a memorandum of co-operation with Japan to work on joint hydrogen projects. Began preparing a New Zealand Green Hydrogen Paper and Hydrogen Strategy. Set up a Green Investment Fund to invest in businesses, including those commercialising hydrogen.
Norway	Awarded funding for development of a hydrogen-powered ferry and a coastal route vessel.
Saudi Arabia	Saudi Aramco and Air Products announced they are to build Saudi Arabia's first hydrogen refuelling station.
South Africa	Included fuel cell vehicles as part of Green Transport Strategy to promote the use of fuel cell public buses in metropolitan and peri-urban areas of the country.
United Kingdom	Set up two GBP 20 million funds for innovation in low-carbon hydrogen supply and innovation in storage at scale including Power-to-X. Published a review of evidence on options for achieving long-term heat decarbonisation, including hydrogen for buildings. Is testing blending of up to 20% hydrogen in part of the UK natural gas network. Announced decarbonising Industrial Clusters Mission supported by GBP 170 million of public investment from the Industrial Strategy Challenge Fund.
United States	Extended and enhanced the 45Q tax credit that rewards the storage of CO_2 in geological storage sites, and added provisions to reward the conversion of CO_2 to other products, including through combination with hydrogen. California amended the Low Carbon Fuel Standard to require a more stringent reduction in carbon intensity by 2030, incentivise development of refuelling stations and enable CCUS operators to participate in generating credits from low-carbon hydrogen. California Fuel Cell Partnership outlined targets for 1 000 hydrogen refuelling stations and 1 000 000 FCEVs by 2030, matching China's targets.

Note: *Co-generation* refers to the combined production of heat and power.

There are multiple mutually reinforcing reasons why this time around might well be different for hydrogen

Hydrogen has never enjoyed so much international and cross-sectoral interest, even in the face of impressive recent progress in other low-carbon energy technologies, such as batteries and renewables. As the cost of technologies has fallen and ambition for tackling climate change and air pollution has risen, understanding of hydrogen's potential role as a flexible complement to electricity has improved. While the level of investment today remains very modest compared to the scale of the energy system, and deployment challenges are significant, the current level of attention has opened a genuine window of opportunity for policy and private-sector action. There are four main reasons for this positive prospect.

1) Greater attention to the deep emissions reductions that hydrogen can help deliver, especially in hard-to-abate sectors

The number of countries establishing ambitious goals for greenhouse gas emissions reduction continues to increase, and with it the number of sectors considering the use of low-carbon hydrogen has risen. The 195 signatories of the 2015 Paris Agreement on climate change agreed to raise their emissions reduction efforts towards net zero emissions from all sectors over the course of the century. In 2018 the Intergovernmental Panel on Climate Change found that global net anthropogenic CO_2 emissions would need to reach net zero around 2050 in a pathway consistent with limited global temperature increases to 1.5°C (IPCC, 2018). The European Union is considering net zero emissions as an objective for 2050 and others seem likely to do the same.

The increased focus on reducing emissions to near zero by mid-century has brought into sharp relief the challenge of tackling hard-to-abate emissions sources. These emissions are in sectors and applications for which electricity is not currently the form of energy at the point of end use, and for which direct electricity-based solutions come with high costs or technical drawbacks.[3] Four-fifths of total final energy demand by end users today is for carbon-containing fuels, not electricity. In addition, much of the raw material for chemicals and other products contains carbon today and generate CO_2 emissions during their processing.

Hard-to-abate emissions sources include aviation, shipping, iron and steel production, chemicals manufacture, high-temperature industrial heat, long-distance and long-haul road transport and, especially in dense urban environments or off-grid, heat for buildings. Rapid technological transformations in these sectors have made limited progress in the face of the costs of low-carbon options, their infrastructure needs, the challenges they pose to established supply chains, and ingrained habits. While significant financial and political commitments will be necessary to realise deep emissions cuts, there is an increasing sense of urgency on the part of governments and companies about the need to start developing appropriate solutions. As a low-carbon chemical energy carrier, hydrogen is a leading option for reducing these hard-to-abate emissions because it can be stored, combusted and combined in chemical reactions in ways that are similar to natural gas, oil and coal. Hydrogen can also technically be converted to "drop-in" low-carbon replacements for today's fuels, which is particularly attractive for sectors with hard-to-abate emissions, especially if there are limits to the direct use of biomass and CCUS.

2) Hydrogen is seen as able to contribute to a wider range of policy objectives

While interest in hydrogen continues to be strongly linked with climate change ambition, there has been a noticeable broadening of the policy objectives to which hydrogen can contribute.

[3] For energy applications that directly use electricity today, confidence is growing in many regions that low-carbon electricity can be cost-competitively supplied to the grid or to off-grid communities, thus decarbonising these end uses without changing fuels. However, achieving a decarbonised electricity supply still faces major economic and technical challenges, in particular in the integration of variable renewable power output.

The benefits of hydrogen for energy security, local air pollution, economic development and energy access are now routinely cited.

Hydrogen can support energy security in several ways. When hydrogen is deployed alongside electricity infrastructure, electricity can be converted to hydrogen and back, or further converted to other fuels, making end users less dependent on specific energy resources and increasing the resilience of energy supplies. Hydrogen produced from fossil fuels with CCUS or from biomass can also increase the diversity of energy sources, especially in a low-carbon economy. If the right infrastructure is developed, it could be attractive in the future for countries to diversify their economies by exporting low-carbon energy in the form of hydrogen and hydrogen-based fuels, or importing hydrogen to benefit from competition that restrains prices. Countries with high-quality resources for hydrogen production are widely dispersed around the globe, and many current energy exporting countries are also endowed with renewable resources that could produce hydrogen. In an ambitious low-carbon context, such hydrogen trade would effectively enable trade and storage of wind and sunshine between different regions to overcome seasonal differences. Lastly, hydrogen could provide an additional way for countries to store reserves of energy strategically in a highly electrified low-carbon world.

Using hydrogen instead of carbon-containing fuels in energy end uses could also reduce local air pollution, improving environmental and health outcomes. Urban air pollution concerns and its related health impacts are now major drivers of energy policy decisions, and governments are keenly interested in ways of reducing air pollution and improving air quality. When used in vehicles and heating appliances, hydrogen does not produce particulates or sulphur oxides or raise ground-level ozone (Stephens-Romero et al., 2009). When used in a fuel cell, hydrogen does not produce nitrogen oxides.

Development of hydrogen infrastructure and technologies is often considered in relation to broader economic development objectives, especially in the context of energy transitions. Hydrogen value chains touch upon many different types of technology and manufacturing sectors. Producing, transmitting and using hydrogen may require chemical technologies, such as carbon capture solvents or fuel cell membranes, and new precision-engineered products, such as storage tank or pipeline materials and burners. There is scope for countries to develop leadership, technical expertise and new jobs in these areas, particularly when they reinforce existing skills and capacities.

While owners of some existing skills and assets would see their value decrease in a low-carbon scenario, much of the value could be conserved by investing in low-carbon solutions that are compatible with current infrastructure. For example, some operators of natural gas grids are now exploring the opportunity to replace natural gas partially with alternatives that have a lower CO_2 intensity, including hydrogen. Likewise, if hydrogen can be used cost-effectively to reduce industrial emissions without any relocation of manufacturing, that would help with the retention of local jobs. Similarly, if CCUS is used to reduce the CO_2 intensity of fossil fuel hydrogen production, that would enable some fossil fuel resources to continue to be used. Transition pathways that make use of existing infrastructure, assets and skills could be easier and cheaper to navigate than the alternatives.

Opportunities for off-grid hydrogen generation and storage systems have emerged from improvements in integrated designs of electrolysers, hydrogen storage and fuel cells. Containerised systems are in development that can be paired with off-grid energy supplies to provide backup power for important facilities such as hospitals and electricity storage for longer periods than battery-based systems. While these systems are still costly, such off-grid solutions can be attractive where electricity demand is modest and the expansion of the electricity grid is not expected in the near term, for example in some parts of Africa. In India hundreds of fuel cells are used to ensure uninterruptible power for telecom towers. Today these systems run largely on imported fossil-based methanol.

3) Hydrogen can help ensure the current rapid growth of renewable electricity continues

Declining renewables costs are one of the forces driving hydrogen's potential upwards. As solar and wind costs become cheaper, their expected share of the future primary energy mix rise. At high proportions of solar and wind power, the variability of their output poses a challenge. A number of countries and regions now have ambitious targets for the share of electricity coming from low-carbon sources, with South Australia aiming for 100% by 2025, Fukushima Prefecture by 2040, Sweden by 2040, California by 2045 and Denmark by 2050. Others have ambitious emissions reduction targets that point in the same direction. The EU objective of reducing emissions by 80–95% by 2050 compared to 1990 levels, for example, implies almost complete decarbonisation of power generation and high levels of variable renewables.

Because hydrogen can be stored or used in a variety of sectors, converting electricity to hydrogen can help with the matching of variable energy supply and demand, both temporally and geographically, alongside alternatives such as pumped-storage hydropower, batteries and grid upgrades. If renewable power generation becomes sufficiently cheap and widespread, it can be used not only to provide low-carbon electricity, but also to create low-carbon hydrogen that can displace fossil fuels in transport, heating and industrial raw materials, and indeed almost any application not susceptible to electrification. All this makes hydrogen one of a suite of technologies that work well together to support the growth of low-carbon energy at the level of the overall energy system.

The question of cost is of course very important in this context. The cost of electricity is the single most significant factor in the cost of electrolytic hydrogen production, and recent sharp declines in solar and wind power costs have therefore reduced the real and expected prices of renewable hydrogen. For example, utility-scale solar photovoltaic (PV) capital costs are 75% lower than in 2010, and electricity from onshore wind is around one quarter cheaper today than it was ten years ago. This has led more potential end users to look closely at whether renewable hydrogen is becoming a competitive way to meet their needs and reduce their environmental impact. Recent investments include a project to use electrolysers for the generation of low-carbon hydrogen to displace a share of fossil fuel-based hydrogen in oil refining and fertiliser production.

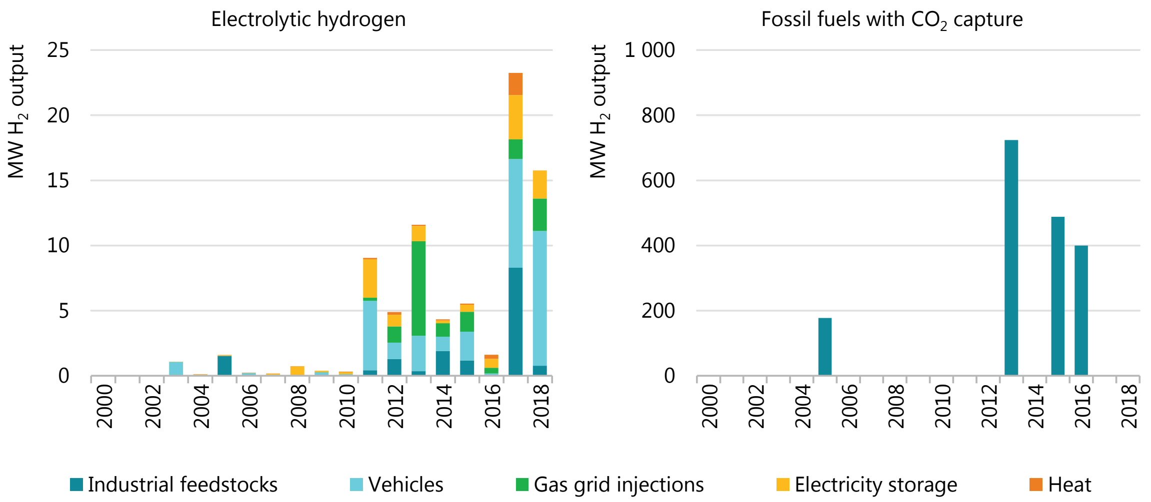
4) Hydrogen can benefit from positive experiences of developing clean energy technologies

Several clean energy technologies have become major new industries since the beginning of this century. While deployment of solar PV and wind turbines was initially backed by direct government support systems and policies, investment in them now stands at USD 124 billion per year, mostly from private capital (IEA, 2019). Electric vehicles are currently following a similar path from government-supported research and pilot projects to a self-sustaining industry. This experience provides today's investors with increased confidence that governments could have the will and capacity to help develop hydrogen, a potentially clean energy technology that largely relies on government-funded projects today, in a similar way and on a similar scale.

Around 11 200 hydrogen-powered cars are already on the road globally, and drivers can choose from several vehicles on the market. Due to the specific advantages of hydrogen in warehouse use, over 20 000 hydrogen forklift trucks are in use. When the IEA published its *Technology Roadmap Hydrogen and Fuel Cells* in 2015, the first commercially available FCEV powered by hydrogen had only recently been launched, and there were just 80 refuelling stations (IEA, 2015). Now there are 381 hydrogen refuelling stations in operation (AFC TCP, 2018). Around 275 000 fuel cell co-generation systems, fed with natural gas, have now been installed in Japan, and fuel cell costs are reported to be around one-third of their 2015 level (a tenth of their 2005 level). Fuel cell durability is up to 10 000 hours, and stationary fuel cells running 80 000 hours have been reported.

There has been a surge in projects for producing hydrogen for energy and climate purposes in recent years. Since 2000 around 230 projects have entered operation around the world to convert electrical energy to hydrogen for a range of energy and climate applications (Figure 4). The capital costs of the water electrolysers commissioned in 2017 and 2018 represent investment of around USD 20–30 million per year, and associated investments in storage tanks, refuelling infrastructure, pipework and other equipment push total project investment even higher. Among these projects, both alkaline and proton exchange membrane (PEM) electrolysers are commonly used: recent projects have tended to favour PEM, possibly reflecting the fact that many of them test environments for less mature technologies that have high potential for cost reduction. Solid oxide electrolyser cells, which promise higher efficiencies, are also beginning to enter this market. To date, electrolyser sizes for these installed projects have been no higher than 10 megawatts (MW_e) (with modules of 2–4 MW_e), and generally much smaller. However, a 20 MW_e project is currently under construction and several project proposals are above the 100 MW_e milestone. A number of the projects have demonstrated the further conversion of hydrogen to synthetic methane, methanol, ammonia and other hydrogen-based fuels and feedstocks.

Figure 4. Capacity of new projects for hydrogen production for energy and climate purposes, by technology and start date



Sources: IEA analysis based on Chehade et al. (2019), "Review and analysis of demonstration projects on Power-to-X pathways in the world", IEA (2018), World Energy Investment, and the World Energy Council (2018), "Hydrogen an enabler of the Grand Transition" and data provided by IEA Hydrogen Technology Collaboration Programme.

Since 2000 nine facilities have begun capturing the CO_2 from fossil fuel-based hydrogen production for industrial applications, although the next such projects are not expected to start for several years. During this period turbines have also been developed to burn 100% hydrogen produced from coal gasification with CCUS. Most of these projects are in North America, but there are also examples in France, Japan and Abu Dhabi. While some sell the captured CO_2 for industrial uses, most store it underground, either via enhanced oil recovery or dedicated geological storage.

While most of these projects received direct public support, including from research budgets, they involve public- and private-sector partners who have shown the technologies to be effective and have learned much about how to manage project risks and contractual considerations. Many stakeholders today share the opinion that technologies such as fuel cells, water electrolysers, hydrogen refuelling and hydrogen turbines are now mainly waiting for large-scale demand and standardisation and not further technological development. Fuel cell costs, in particular, are expected to greatly benefit from mass manufacturing (Chapter 5).

However, significant challenges remain

While the factors in favour of a sustained upswing in investment in hydrogen are much stronger and better aligned than in any prior period, significant challenges still need to be addressed. Overcoming these challenges will be central to launching the virtuous cycle for hydrogen that has benefited other clean energy technologies: (a) policy support and regulatory changes stimulate first movers in low-risk applications; (b) a positive track record attracts private finance and enables a policy shift from direct support to market-based incentives; (c) high and widespread expectations for deployment unlock public and private investment in long-lasting infrastructure and manufacturing; (d) the creation of a multi-billion dollar marketplace stimulates cost reductions through competition and innovation; (e) customers, investors and suppliers become reliant on the technology and each other, providing long-term stability.

Policy makers and businesses around the world are currently working with a wide range of stakeholders to tackle challenges and reduce the risks that currently slow progress through the first two of these steps. The challenges can be grouped into three broad categories.

Challenge 1) Policy and technology uncertainty

Climate change ambition remains the single most important driver for widespread use of clean hydrogen. The speed with which governments will push the transition to low-carbon energy sources in different countries and sectors remains a major uncertainty. While low-carbon hydrogen can be attractive in the near term in certain applications, its major strength is its ability to help deliver very low emissions pathways and manage very high levels of variable renewable electricity. In the absence of clear, and ideally binding, commitments to sustainable and resilient energy systems in the long term, major financial commitments to hydrogen technologies and infrastructure are much less attractive. Policy frameworks that support revenue from low-carbon hydrogen projects in the near term are also required and, despite recent government activity, they are not fully developed in most countries and regions. In some countries this reflects the lack of overarching long-term energy strategies, but it also signifies technology uncertainty.

Most applications for low-carbon hydrogen are not cost-competitive without direct government support. Yet the relative costs of producing hydrogen from different sources in different regions, and how they will compete in the future, are unclear. This makes it difficult to compare potential future hydrogen prices with those of alternatives such as solid-state batteries, pumped-storage hydropower, electric vehicles, biofuels and electrification of high-temperature heat, many of which have head starts and could reap the benefits of path dependency. In the case of fuel cells, the speed of cost reduction is a key factor, yet experts disagree on the relationship between the scale of fuel cell demand, cost and performance improvements.

Technology uncertainty is also evident in discussions about the ways in which hydrogen could be transported over long distances, and the formats in which it could be delivered to end-users.

Challenge 2) Value chain complexity and infrastructure needs

Hydrogen value chains can follow many different paths (Figure 5). Demand for low-carbon hydrogen can come from a variety of sectors, and there are many permutations of hydrogen supply and handling that could meet it. The most cost-competitive outcome will, moreover, be different in various regions and applications. For each possible value chain, investments and policies need to be synchronised in scale and time if hydrogen is to be produced and delivered to end users that are ready to use it. Building trust throughout the value chain so that investments are co-ordinated takes time and may require new contractual relationships. In some cases, governments and companies will need to think and act cross-sectorally in new ways to take full advantage of hydrogen's flexibility.

Infrastructure such as pipeline and delivery networks is of particular importance for a new energy carrier such as hydrogen. While hydrogen can be produced locally, its storage and distribution benefit from economies of scale. When produced from fossil fuels in particular, its supply is cheaper when centralised. In the case of hydrogen use for road transport, where a network of refuelling stations will be a precondition for widespread adoption of FCEVs, the current pace of infrastructure development is a brake on adoption. The ability of governments to commit to large (and necessary) infrastructure investments is limited in many countries and regions: public–private investment models can help, but may add further complexity. In some cases, these investments will also need to be co-ordinated across borders, requiring international collaboration at a level not yet seen for hydrogen.

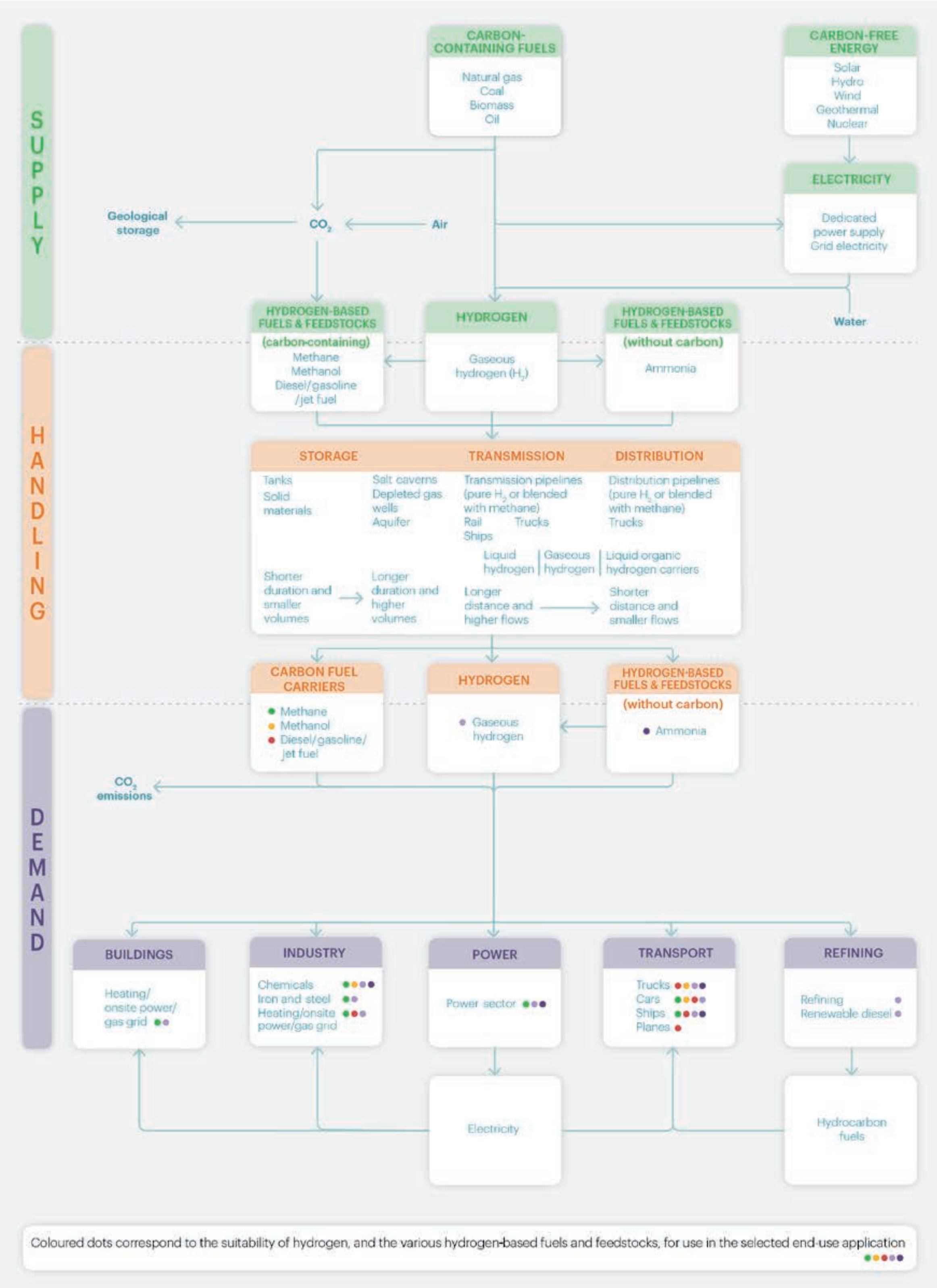
Challenge 3) Regulations, standards and acceptance

Around the world, the state of existing regulations and standards currently limits hydrogen uptake. Certain regulations are unclear or not written with new uses of hydrogen in mind and do not allow exploitation of the full benefits hydrogen can provide. They deal with a range of technical but important questions such as how and where pressurised or liquefied hydrogen can be used, who can handle hydrogen, where hydrogen vehicles can go, tax regimes for conversion between energy carriers, whether CO_2 can be stored, and how much hydrogen can be present in natural gas pipelines. They need to be updated if hydrogen is to have the opportunity to fulfil its potential.

Some important standards have yet to be agreed, including standards dealing with hydrogen vehicle refuelling, gas composition for cross-border sales, safety measures, permitting, materials and how to measure lifecycle environmental impacts. The issue of lifecycle 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. Unlike electricity, hydrogen and hydrogen-based fuels can be blended with fossil fuels in mixtures that end-users cannot identify. 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.

Hydrogen comes with safety risks, high upfront infrastructure costs and some of the industrial dynamics of fossil fuel supply and distribution, especially when paired with CCUS. It is not yet clear how citizens will react to these aspects of hydrogen, or how they will weigh them alongside the convenience and environmental benefits of some hydrogen applications, as well as the potential importance of hydrogen to long-term sustainability.

Figure 5. A guide to the hydrogen energy value chain, from supply to end use



Source: IEA 2019. All rights reserved.

Hydrogen can be produced from a wide variety of sources and used in a wide variety of applications, with value chains containing different combinations of supply, handling and demand technologies.

The crucial role for governments

The risk that today's interest in hydrogen does not translate into sustainable deployment and instead leads to a further cycle of disappointment is very real. Governments have a central role to play in avoiding this outcome and in helping hydrogen to achieve its potential. That raises the question of how far governments should go to facilitate the uptake of low-carbon hydrogen in the near term. Governments might be tempted to take a technology-neutral approach and leave it to the market to decide which technologies are adopted. This approach is generally sensible, but for the case of hydrogen there are also strong arguments for governments to take a more enabling approach. Indeed, as described previously, a number of governments are already doing so, as they have previously done for various low-carbon technologies.

This report sets out to help public and private decision makers by providing the following:

- Chapters 2 to 5 combine key facts about hydrogen and energy with rigorous analysis. They deal with the supply of hydrogen (Chapter 2); its storage, transmission and distribution (Chapter 3); and its various end-use applications (Chapters 4 and 5). The cutting-edge analysis, including sensitivities, is intended to help governments put the facts into context and gauge their importance. This report does not present new scenarios for hydrogen deployment, but instead outlines the current status of technologies, their possible future development, and their economic and policy context (Box 2). Further work at both a global and local level will be required to inform specific policies, building upon the foundation provided by this report and the rapidly growing evidence base around the world.
- Chapter 6 provides suggestions for policies to build a springboard for hydrogen's greater use over the next decade via the most promising near-term value chains. It identifies four real-world interconnected value chains that offer realistic potential to scale up clean hydrogen and to reduce costs, and concludes by highlighting specific, action-oriented recommendations for governments to consider.

There are no easy answers to the questions currently facing decision makers, but the report finds several compelling reasons why governments might choose to consider boosting their efforts in support of low-carbon hydrogen. Individual governments will of course rightly want to weigh all the relevant facts, consider the analysis and come to their own conclusions in the light of their own circumstances. This report is intended to help inform deliberations and decisions by governments, as well as to inform discussions among governments and between governments and companies and other stakeholders.

Box 2. How this report manages uncertainties about present and future costs and potentials

The aim of this report is not to describe a vision for hydrogen in a future energy system, but rather to outline the status of technologies and their possible future development, and to describe their economic and policy context. Given the level of uncertainty about some of the relevant technologies and their competitors, certain assumptions have been made in order to present reasonable comparisons for the present and the future.

Parameters for the cost and performance of technologies have been based on extensive literature analysis, conversations with experts and peer review. The values behind the numbers and charts in the report are listed in an annex to the report that is available to download from the IEA website. For ease of use, single values or mid-points are given in the text and figures in many places. In some cases, and in particular for less mature technologies, this approach does not reflect the full range of different values quoted by reliable experts in the field. To the extent possible, other considerations relating to social and political headwinds and tailwinds are highlighted and material provided on the IEA website for readers to explore sensitivity analyses.

For the purposes of illustration, this report presents examples of costs and levels of demand at three different times: today (with 2018 as the base year), 2030, and the long term (the period after 2030). For future time periods, fuel prices, levels of demand and other parameters are extracted from recent IEA global energy system modelling exercises. Where current trends to 2030 are referenced, these are in line with the New Policies Scenario of the IEA *World Energy Outlook 2018* (IEA, 2018c). Where pathways compatible with the goals of the Paris Agreement on climate change are referenced, these are in line with the Sustainable Development Scenario (SDS) of the IEA *World Energy Outlook 2018*. The SDS is fully aligned with the Paris Agreement's goal of holding the increase in the global average temperature to well below 2°C above pre-industrial levels and pursuing efforts to limit the temperature increase to 1.5°C, as well as with the achievement of the United Nations Sustainable Development Goals on universal access to energy and reducing the severe health impacts of air pollution.

Hydrogen and energy: A primer

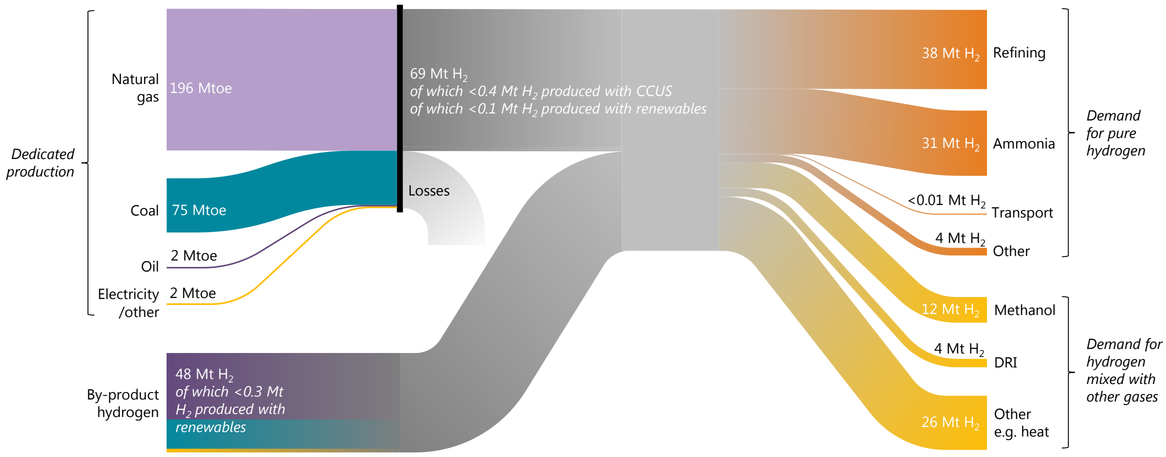
How is hydrogen produced and used today?

This report identifies around 70 million tonnes (Mt) of current demand worldwide for "pure" hydrogen, with "pure" meaning that the specific applications require hydrogen with only small levels of additives or contaminants tolerated (Figure 6). The main applications for this hydrogen are oil refining and ammonia production, mainly for fertilisers. A further 45 Mt of demand exists for hydrogen as part of a mixture of gases, such as synthesis gas, for fuel or feedstock. The main applications for hydrogen as part of a mixture of gases are methanol production and steel production. While one-third of hydrogen demand today is for transport sector applications in a broad sense – in refineries and for methanol used in vehicle fuel – less than 0.01 Mt per year of pure hydrogen (less than 0.03 Mtoe) is used in FCEVs, most of which is derived from natural gas.

The overwhelming majority of hydrogen produced today is from fossil fuels, and around 60% of it is produced in "dedicated" hydrogen production facilities, meaning that hydrogen is their primary product. Most of this is produced from natural gas, though some comes from coal, and a small fraction comes from water electrolysis (a process that produces hydrogen from water and electricity). One-third of global supply is "by-product" hydrogen, meaning that it comes from facilities and processes designed primarily to produce something else. This by-product hydrogen often needs dehydrating or other types of cleaning, and can then be sent to a variety of hydrogen-using processes and facilities. Most hydrogen is currently produced near to its end use, using resources extracted in the same country.

Overall, less than 0.7% of current hydrogen production is from renewables or from fossil fuel plants equipped with CCUS. In total, hydrogen production today is responsible for 830 $MtCO_2$/yr. In general, demand for pure hydrogen that is supplied from dedicated facilities is the most straightforward to replace with alternative sources of low-carbon hydrogen.

Figure 6. Today's hydrogen value chains



Notes: Other forms of pure hydrogen demand include the chemicals, metals, electronics and glass-making industries. Other forms of demand for hydrogen mixed with other gases (e.g. carbon monoxide) include the generation of heat from steel works arising gases and by-product gases from steam crackers. The shares of hydrogen production based on renewables are calculated using the share of renewable electricity in global electricity generation. The share of dedicated hydrogen produced with CCUS is estimated based on existing installations with permanent geological storage, assuming an 85% utilisation rate. Several estimates are made as to the shares of by-products and dedicated generation in various end uses, while input energy for by-product production is assumed equal to energy content of hydrogen produced without further allocation. All figures shown are estimates for 2018. The thickness of the lines in the Sankey diagram are sized according to energy contents of the flows depicted.

Source: IEA 2019. All rights reserved.

Today's hydrogen industry is large, with many sources and uses. Most hydrogen is produced from gas in dedicated facilities, and the current share from renewables is small.

Chapter 2 provides more detail on the processes and costs of hydrogen production. It concludes that production costs are highly dependent on factors such as electricity costs and taxes, grid fees, natural gas prices, the availability and price of CCUS services, and the capacity utilisation rates of electrolysers. The price of hydrogen varies widely between regions and end uses (different end uses require different volumes, pressures and purity levels of hydrogen); it also varies according to the way that hydrogen is transported.

What does it mean to be a chemical energy carrier and not an energy source?

Hydrogen is not an energy source but an energy carrier, which means that its potential role has similarities with that of electricity. Both hydrogen and electricity can be produced by various energy sources and technologies. Both are versatile and can be used in many different applications. No greenhouse gases, particulates, sulphur oxides or ground level ozone are produced from the use of either hydrogen or electricity. If the hydrogen is used in a fuel cell, it emits nothing but water. However, both hydrogen and electricity can have a high CO_2 intensity upstream if produced from fossil fuels such as coal, oil or natural gas. This disadvantage can only be overcome by using renewables or nuclear as the initial energy input, or equipping fossil fuel plants with CCUS.

The crucial difference between hydrogen and electricity is that hydrogen is a chemical energy carrier, composed of molecules and not only electrons. This distinction underpins all the reasons why hydrogen might outcompete electricity in some situations (and vice versa). Chemical energy is attractive because it can be stored and transported in a stable way, as is done today with oil, coal, biomass and natural gas.[4] Molecules can be stored for long periods, transported across the sea in ships, burned to produce high temperatures, and used in existing infrastructure and business models designed around fossil fuels. Because of its molecular nature, hydrogen can also be combined with other elements such as carbon and nitrogen to make hydrogen-based fuels that are easier to handle, and can be used as feedstock in industry, helping to reduce emissions.

Without hydrogen a decarbonised energy system based on electricity would be much more flow-based. Flow-based energy systems must match demand and supply in real time, across wide distances, and can be vulnerable to disruptions of supply. Chemical energy can add a stock-based element to an energy economy and thus contribute significantly to energy system resilience.

All energy carriers, including fossil fuels, encounter efficiency losses each time they are produced, converted or used. In the case of hydrogen, these losses can accumulate across different steps in the value chain. After converting electricity to hydrogen, shipping it and storing it, then converting it back to electricity in a fuel cell, the delivered energy can be below 30% of what was in the initial electricity input. This makes hydrogen more "expensive" than electricity or the natural gas used to produce it. It also makes a case for minimising the number of conversions between energy carriers in any value chain.

That said, in the absence of constraints to energy supply, and as long as CO_2 emissions are valued, efficiency can be largely a matter of economics, to be considered at the level of the whole value chain. This is important as hydrogen can be used with much higher efficiency in certain applications and has the potential to be produced without greenhouse gas emissions. For example, a hydrogen fuel cell in a vehicle is around 60% efficient, whereas a gasoline internal combustion engine is around 20% efficient, and a modern coal-fired power plant is around 45% efficient, with electricity power line losses accounting for a further 10% or more.

What is the difference between hydrogen and hydrogen-based fuels and feedstocks?

Hydrogen can be used in its pure form as an energy carrier or as an industrial raw material. It can also be combined with other inputs to produce what are referred to as hydrogen-based fuels and feedstocks. Hydrogen-based fuels and feedstocks can be produced using hydrogen from any source, whether electricity, biomass or fossil fuels, and can readily be used in applications such as engines, turbines and chemical processes. They include such derivative products as synthetic methane, synthetic liquid fuels and methanol, all of which require carbon alongside hydrogen. They also include ammonia, which can be used as a chemical feedstock or potentially as a fuel, and which is made by combining hydrogen with nitrogen.

[4] Batteries also store chemical energy, but not in the bonds of molecules that can be stored in bulk. In batteries, the chemical energy is a build-up of ions and electrons on cathodes and anodes in specially prepared combinations of chemicals; often these are complex chemicals with poor stability. The chemical energy in batteries degrades more quickly over time.

This report considers the production and use of both hydrogen and hydrogen-based fuels and feedstocks. They all generate demand for hydrogen, and they can all contribute to energy security as well as to decarbonisation, although different production routes will have different CO_2 intensities.

Power-to-X is a commonly used term for the conversion of electricity to other energy carriers or chemicals, generally through hydrogen produced by the electrolysis of water. The "X" can stand for any resulting fuel, chemical, power or heat. For example, power-to-gas refers to the production of electrolytic hydrogen itself or synthetic methane produced from electrolytic hydrogen combined with CO_2. Likewise, power-to-liquids refers to the production of hydrogen-based liquid fuels. Together, hydrogen-based fuels that integrate electrolytic hydrogen are sometimes referred to as "electrofuels" or, in the very specific case of power from solar energy, solar fuels.[5]

Why do some people talk about black, blue, brown, green and grey hydrogen?

In recent years, colours have been used to refer to different sources of hydrogen production. "Black", "grey" or "brown" refer to the production of hydrogen from coal, natural gas and lignite respectively. "Blue" is commonly used for the production of hydrogen from fossil fuels with CO_2 emissions reduced by the use of CCUS. "Green" is a term applied to production of hydrogen from renewable electricity. In general, there are no established colours for hydrogen from biomass, nuclear or different varieties of grid electricity. As the environmental impacts of each of these production routes can vary considerably by energy source, region and type of CCUS applied, colour terminology is not used in this report.

This report highlights low-carbon hydrogen production routes. This includes hydrogen from renewable and nuclear electricity; it also includes hydrogen from biomass and fossil fuels with CCUS, provided that upstream emissions are sufficiently low, that CO_2 capture is applied to all the associated CO_2 streams, and that the CO_2 is prevented from reaching the atmosphere. The same principle applies to low-carbon hydrogen-based fuels and feedstocks made using low-carbon hydrogen and a sustainable carbon source.

What are the most relevant physical properties of hydrogen?

Hydrogen contains more energy per unit of mass than natural gas or gasoline, making it attractive as a transport fuel (Table 2). However, hydrogen is the lightest element and so has a low energy density per unit of volume. This means that larger volumes of hydrogen must be moved to meet identical energy demands as compared with other fuels. This can be achieved, for example, through the use of larger or faster-flowing pipelines and larger storage tanks. Hydrogen can be compressed, liquefied, or transformed into hydrogen-based fuels that have a higher energy density, but this (and any subsequent re-conversion) uses some energy.

[5] Broader definitions have been noted elsewhere, with electrofuels including biochemical processes that use electricity as an input, but do not pass via electrolytic hydrogen as an intermediate (Ridjan, 2016).

Table 2. Physical properties of hydrogen

Property	Hydrogen	Comparison
Density (gaseous)	0.089 kg/m^3 (0°C, 1 bar)	1/10 of natural gas
Density (liquid)	70.79 kg/m^3 (-253°C, 1 bar)	1/6 of natural gas
Boiling point	-252.76°C (1 bar)	90°C below LNG
Energy per unit of mass (LHV)	120.1 MJ/kg	3x that of gasoline
Energy density (ambient cond., LHV)	0.01 MJ/L	1/3 of natural gas
Specific energy (liquefied, LHV)	8.5 MJ/L	1/3 of LNG
Flame velocity	346 cm/s	8x methane
Ignition range	4–77% in air by volume	6x wider than methane
Autoignition temperature	585°C	220°C for gasoline
Ignition energy	0.02 MJ	1/10 of methane

Notes: cm/s = centimetre per second; kg/m^3 = kilograms per cubic metre; LHV = lower heating value; MJ = megajoule; MJ/kg = megajoules per kilogram; MJ/L = megajoules per litre.

What are the health and safety considerations?

Like other energy carriers, hydrogen presents certain health and safety risks when used on a large scale. Safety considerations and incidents can slow, or even prevent, the deployment of a new energy technology if the risks are not well communicated and managed. CCUS is a salient example, and lithium-ion batteries have also faced concerns. On the other hand, the health and safety impacts of established energy products – gasoline, diesel, natural gas, electricity, coal – for consumers are familiar and rarely questioned, showing that risks – including flammability, presumed carcinogenicity and toxicity – can be managed to the satisfaction of users.

As a light gas of small molecules, hydrogen requires special equipment and procedures to handle it. Hydrogen is so small it can diffuse into some materials, including some types of iron and steel pipes, and increase their chance of failure. It also escapes more easily through sealings and connectors than larger molecules, such as natural gas. Chapter 3 discusses the considerable potential for use of existing natural gas infrastructure despite these issues.

Hydrogen is a non-toxic gas, but its high flame velocity, broad ignition range and low ignition energy make it highly flammable. This is partly mitigated by its high buoyancy and diffusivity, which causes it to dissipate quickly. It has a flame that is not visible to the naked eye and it is colourless and odourless, making it harder for people to detect fires and leaks. There are already many decades of experience of using hydrogen industrially, including in large dedicated distribution pipelines. Protocols for safe handling at these sites are already in place, and they also exist for hydrogen refuelling infrastructure in site-specific forms. However, they remain complex and unfamiliar compared to those for other energy carriers. Widespread use in the energy system would bring new challenges. They would need further development and any public concerns would need to be alleviated.

The health and safety considerations of most hydrogen-based fuels and feedstocks are familiar to the energy sector. The exceptions are ammonia and liquid organic hydrogen carriers (LOHCs, discussed in Chapter 3), which have only recently been seriously considered for potential use in the energy system. Ammonia generally raises more health and safety considerations than hydrogen, and its use would probably need to continue to be restricted to professionally trained operators. It is highly toxic, flammable, corrosive, and escapes from leaks in gaseous form. However, unlike hydrogen, it has a pungent smell, making leaks easier to detect. It is also a precursor to air pollution. Like hydrogen, there is long experience of using ammonia industrially. It has been used as a refrigerant since the early 19th century and it has also been used in large-scale fertiliser production for over a century. Ammonia is routinely stored and transported, including in ocean-going tankers, and is sometimes injected directly into the soil in agriculture. Methylcyclohexane, a potential candidate LOHC, is flammable and dangerous to ingest, and its production requires toluene (which is toxic), but as a liquid, methylcyclohexane is less hazardous compared with gases, which can be inhaled. Dibenzyltoluene is considered to be an alternative LOHC option and is safer. Neither are currently handled in very large quantities, except in specific chemical facilities, but safe handling in pipelines or ships is not thought to pose a significant safety problem with appropriate controls in place.

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Chapter 2: Producing hydrogen and hydrogen-based products

- **Around 70 Mt of dedicated hydrogen are produced today, 76% from natural gas and almost all the rest (23%) from coal.** Annual hydrogen production consumes around 205 billion m^3 of natural gas (6% of global natural gas use) and 107 Mt of coal (2% of global coal use), with coal use concentrated in the People's Republic of China ("China"). As a consequence, global hydrogen production today is responsible for 830 $MtCO_2$/yr – corresponding to the annual CO_2 emissions of Indonesia and the United Kingdom combined.

- **Electrolysis currently accounts for 2% of global hydrogen production, but there is significant scope for electrolysis to provide more low-carbon hydrogen.** Surplus electricity from variable renewables has low costs, but the number of hours during which this surplus occurs is generally low. Falling costs mean that dedicated renewables for hydrogen production in regions with excellent resource conditions could, however, now become a reliable low-cost hydrogen source. If all current dedicated hydrogen production were produced through water electrolysis (using water and electricity to create hydrogen), this would result in an annual electricity demand of 3 600 TWh – more than the annual electricity generation of the European Union. Water requirements would be 617 million m^3, or 1.3% of the water consumption of the global energy sector today; this is roughly twice the current water consumption for hydrogen from natural gas.

- **There are huge regional variations in hydrogen production costs today, and their future economics depend on factors that will continue to vary regionally, including prices for fossil fuels, electricity and carbon.** Natural gas without CCUS is currently the most economic option for hydrogen production in most parts of the world, with costs being as low as USD 1/kgH_2 in the Middle East. Among low-carbon options, electrolysis requires electricity prices of USD 10–40/MWh and full load hours of 3 000–6 000 to become cost-competitive with natural gas with CCUS (depending on local gas prices). Regions with good renewable resources or nuclear power plants may find electrolysis an attractive option, especially if they currently depend on relatively high cost natural gas imports.

- **Conversion of hydrogen into other hydrogen-based fuels could be attractive where few other low-carbon alternatives are available, but is not economic at current prices.** The conversion of hydrogen to ammonia benefits from existing infrastructure and demand; it also does not need carbon as an input. For synthetic liquid fuels from electrolytic hydrogen, however, electricity costs of USD 20/MWh translate into costs of USD 60–70/bbl without taking account of any capital expenditure or CO_2 feedstock costs. For synthetic methane the equivalent figure is USD 10–12/MBtu. Carbon pricing or equivalent policies would be needed to reduce the cost gap between synthetic hydrocarbons and fossil fuels.

Hydrogen can be produced using a range of energy sources and technologies. Global hydrogen production today is dominated by the use of fossil fuels. Electrolytic hydrogen – that is, hydrogen produced from water and electricity – plays only a minor role (although it was a major source of industrial hydrogen in the 1920s to 1960s, using electricity generated from hydropower, before being displaced by natural gas). With declining costs for renewable power (in particular solar PV and wind), interest is now growing in water electrolysis for hydrogen production and in the scope for further conversion of that hydrogen into hydrogen-based fuels or feedstocks, such as synthetic hydrocarbons and ammonia, which are more compatible than hydrogen with existing infrastructure.

This chapter explores the various ways of making hydrogen and hydrogen products. It begins with an analysis of the existing sources and methods of production of hydrogen. It then considers key sources of hydrogen production, looking in turn at natural gas, water and electricity, coal, and biomass in terms of both technology options and costs. The chapter then provides an overview of the scope for converting hydrogen into fuels and feedstocks that are easier than hydrogen to store, transport and use.

Production of hydrogen today

Hydrogen can be extracted from fossil fuels and biomass, or from water, or from a mix of both (Figure 7). Around 275 Mtoe of energy are used for the production of hydrogen today (2% of global total primary energy demand). Natural gas is currently the primary source of hydrogen production, and steam methane reformers using natural gas are the workhorse of dedicated hydrogen production in the ammonia and methanol industries and in refineries. Natural gas accounts for around three-quarters of the annual global dedicated hydrogen production of around 70 million tonnes of hydrogen (MtH_2), using around 205 billion cubic metres (bcm) of natural gas (6% of global natural gas use). Coal comes next, due to its dominant role in China: it accounts for an estimated 23% of global dedicated hydrogen production and uses 107 Mt of coal (2% of global coal use). Oil and electricity account for the remainder of the dedicated production.

The dependence on natural gas and coal means that hydrogen production today generates significant CO_2 emissions: 10 tonnes of carbon dioxide per tonne of hydrogen (tCO_2/tH_2) from natural gas,[6] 12 tCO_2/tH_2 from oil products, and 19 tCO_2/tH_2 from coal. This results in total CO_2 formation of about 830 $MtCO_2$/yr, corresponding to the combined CO_2 emissions of Indonesia and the United Kingdom. Most of this CO_2 is emitted to the atmosphere, although in ammonia/urea plants the concentrated CO_2 streams from steam methane reforming (SMR) (around 130 $MtCO_2$ each year) are captured and used in the production of urea fertiliser.[7]

Reforming is the most widespread method for producing hydrogen from natural gas. There are three methods: steam reforming (using water as an oxidant and a source of hydrogen), partial oxidation (using oxygen in the air as the oxidant), or a combination of both called autothermal reforming (ATR).[8] Steam reforming is used to extract hydrogen from natural gas and – much

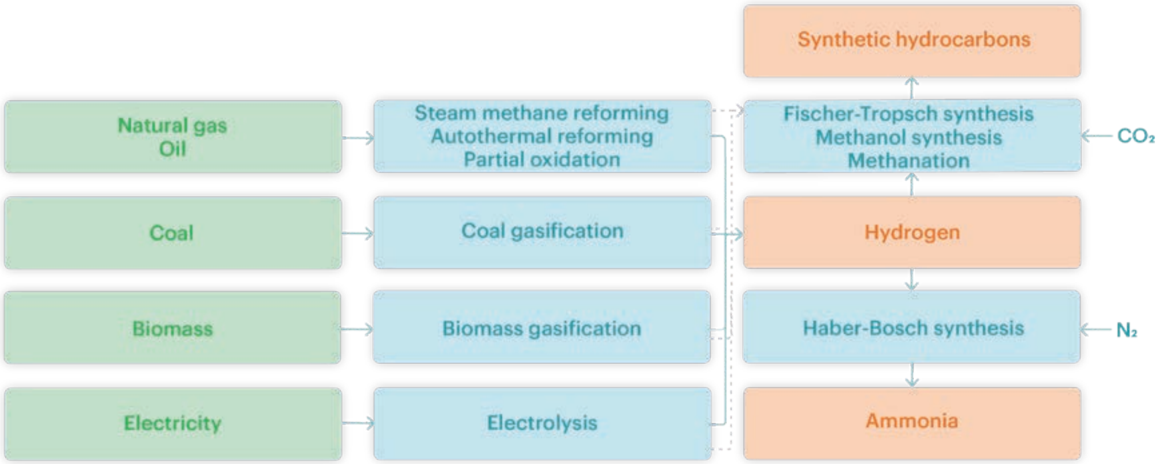
[6] Fugitive emissions during natural gas production, processing and transport are important to consider when comparing different hydrogen production routes as they represent a significant share of the CO_2 mitigation potential (Tlili et al., 2019).

[7] The carbon contained in the urea fertiliser is, however, released again as CO_2 when the fertiliser is applied by farmers to the soil.

[8] Steam reforming requires heat ("endothermic"), while partial oxidation releases heat ("exothermic"). ATR uses both air and water as oxidants, so it does not require or release heat.

less frequently – from liquefied petroleum gas and naphtha. Partial oxidation is used to extract hydrogen from heavy fuel oil and coal. In all cases, a synthesis gas mostly made of carbon monoxide and hydrogen is formed, then converted to hydrogen and CO_2 if pure hydrogen is the main product. Other processes include gasification (where the raw material, such as coal or biomass, is converted into a synthesis gas that is then transformed into hydrogen and CO_2) and electrolysis (where hydrogen is produced by splitting water into hydrogen and oxygen). Though known for a long time, electrolysis plays only a minor role in total hydrogen production today, mostly in the chlor-alkali industry where hydrogen is a by-product.

Figure 7. Potential pathways for producing hydrogen and hydrogen-based products



Notes: N_2 = nitrogen. The dotted lines represent the flow of hydrogen-containing synthesis gas (mixture of hydrogen and carbon monoxide) from hydrocarbon fuels for further conversion into other synthetic hydrocarbons, such as coal-to-liquids or gas-to-liquids. Though not discussed in this chapter, this direct conversion route of hydrocarbons via synthesis gas into other synthetic hydrocarbons is likely more favourable in terms of emissions (especially when coupled with CCUS) or costs compared with producing pure hydrogen from hydrocarbons first and then combining this hydrogen again with CO_2 for the production of synthetic hydrocarbons, particularly if the CO_2 input is of fossil origin.

Source: IEA 2019. All rights reserved.

Various options exist to produce hydrogen, with SMR, coal gasification and water electrolysis being the prevalent ones today.

Hydrogen from natural gas

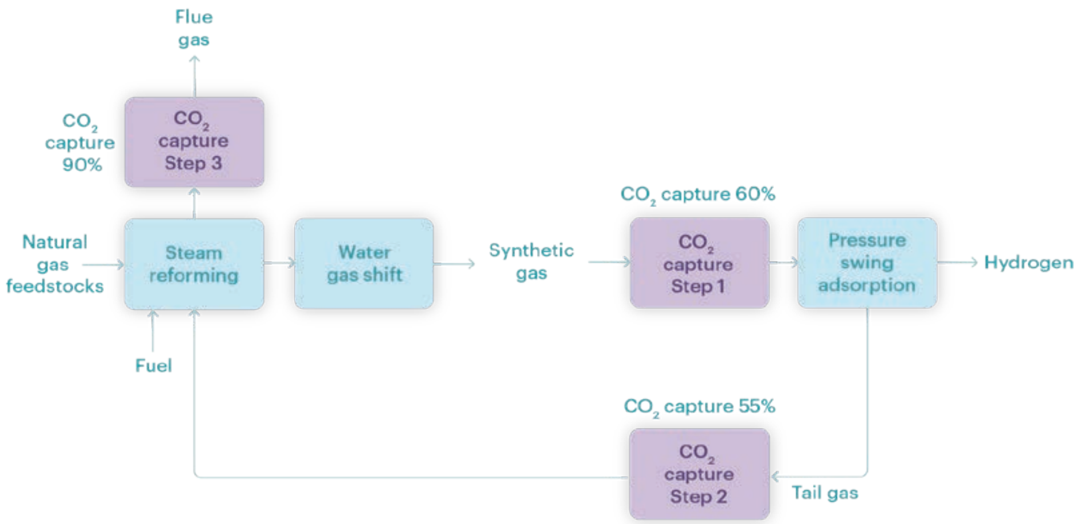
SMR is the most widespread technology for hydrogen production from natural gas at large scale, though ATR is also in use. Natural gas in SMR is both a fuel and a feedstock (together with water). Typically 30–40% of it is combusted to fuel the process, giving rise to a "diluted" CO_2 stream, while the rest of it is split by the process into hydrogen and more concentrated "process" CO_2. SMR is likely to remain the dominant technology for large-scale hydrogen production in the near term because of its favourable economics and the large number of SMR units in operation today.

Technology options for low-carbon hydrogen

CCUS can be applied both to SMR and ATR hydrogen production. Using CCUS with SMR plants can lead to a reduction in carbon emissions of up to 90%, if applied to both process and energy emission streams. Several SMR-CCUS plants are already operational today, producing around

0.5 MtH_2/yr between them. There are several ways in which CO_2 capture can take place at an SMR plant. CO_2 can be separated from the high-pressure synthesis gas stream, reducing emissions by up to 60% (Figure 8). This typically costs around USD 53 per tonne of carbon dioxide (tCO_2) for merchant plants (that is, plants where hydrogen production is not integrated with the production of ammonia or methanol), based on current natural gas prices in Europe. CO_2 can also be captured from the more diluted furnace flue gas. This can boost the level of overall emission reduction to 90% or more, but it also increases costs to around USD 80/tCO_2 in merchant plants, and to USD 90–115/tCO_2 in integrated ammonia/urea and methanol plants, which have more diluted CO_2 streams (see IEAGHG, 2017a and 2017b).

Figure 8. Production process of hydrogen from gas with CCUS



Source: IEAGHG (2017a), "Reference data and supporting literature reviews for SMR based hydrogen production with CCS".

CCUS is crucial to decarbonising the large SMR fleet in operation today.

ATR is an alternative technology in which the required heat is produced in the reformer itself. This means that all the CO_2 is produced inside the reactor, which allows for higher CO_2 recovery rates than can be achieved with SMR. ATR also allows for the capture of emissions at lower cost than SMR because the emissions are more concentrated. A number of studies have shown that the costs of SMR with capture rates exceeding 90% are higher than that of a comparable ATR system (H21, 2018). A large share of global ammonia and methanol production already combines SMR with ATR technology, and the announced HyNet and H21 projects in the United Kingdom have plans to use ATR with CCUS instead of SMR. Other options for using natural gas to produce hydrogen exist, but are still only at either demonstration or laboratory scale today (Box 3).

Box 3. Emerging technologies to produce hydrogen

Methane splitting offers a potential new way to produce hydrogen from natural gas. Various technologies have been developed since the 1990s. The main technology is based on alternating-current three-phase plasma, and uses methane as a feedstock and electricity as an energy source. It produces hydrogen and solid carbon, but no CO_2 emissions (Fulcheri, 2018).

Methane splitting requires high-temperature plasma and significant thermal losses reduce its efficiency advantage, but it uses three to five times less electricity than electrolysis for the same amount of hydrogen produced. It has very low CO_2 formation and creates solid carbon in the form of carbon black. It requires more natural gas than electrolysis, but could create additional revenue streams from the sale of carbon black for use in rubber, tyres, printers and plastics. The US firm Monolith Materials operates a pilot methane splitting plant in California and is building an industrial plant in Nebraska; the Nebraska plant will ultimately be run on low-carbon electricity and sell hydrogen to the Nebraska Public Power District, which plans to convert a 125 MW coal plant to burn hydrogen instead of coal. Although the total efficiency would be lower than using the natural gas directly in the power plant, the emissions from gas combustion would be avoided and the hydrogen would effectively be a "store" of input electricity for the power network.

Global demand for carbon black is expected to increase from 12 Mt to 16 Mt in the next five years, which would have significant accompanying CO_2 emissions using current technology. Producing under 5 MtH_2/yr of hydrogen via methane splitting could substitute all this demand and avoid these emissions. Markets for other exotic forms of solid carbon – carbon nanotubes, carbon fibres, graphene – are one to two orders of magnitude smaller than that for carbon black, but could grow rapidly with the expansion of batteries or carbon-reinforced concrete (Dagle et al., 2017). Other solid carbon markets may provide other options (Hanson, 2018).

Meanwhile, alternative process designs for SMR are being explored. While natural gas would still be required as feedstock, other energy sources could be used to produce the necessary steam, and this could facilitate the capture of the more concentrated "process" CO_2 stream. Electricity is a potential candidate for the production of the necessary high-temperature steam (Bazzanella and Ausfelder, 2017), while concentrating solar heat could be used in areas with the right kind of solar resources.

If even higher levels of solar concentration could generate temperatures of around 800–1 000°C, solar energy could be used directly to split water into hydrogen and oxygen without the need for natural gas and CO_2 storage. The technology for these higher solar concentration levels, however, is still at laboratory scale.

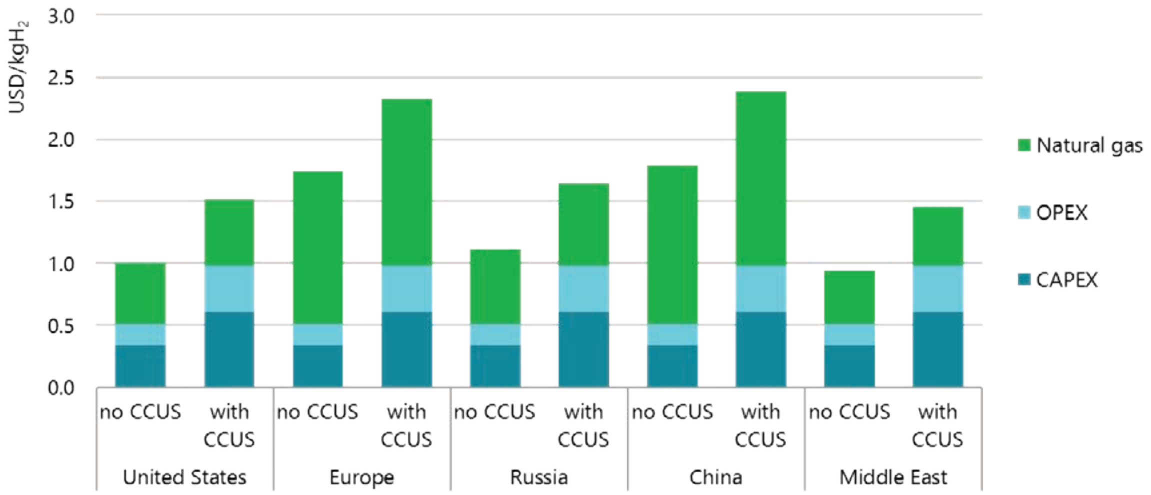
Sources: Fulcheri (2018), "Direct decarbonization of methane by thermal plasma for the co-production of hydrogen and carbon nanostructures"; Dagle et al. (2017), "An overview of natural gas conversion technologies for co-production of hydrogen and value-added solid carbon products"; Bazzanella and Ausfelder (2017), "Low carbon energy and feedstock for the European chemical industry"; and personal communication with Rob Hanson, 2018.

Costs of hydrogen production from natural gas

The production cost of hydrogen from natural gas is influenced by various technical and economic factors, with gas prices and capital expenditure (CAPEX) being the two most important.

Fuel costs are the largest cost component in all regions and account for between 45% and 75% of production costs (Figure 9). Low gas prices in the Middle East, the Russian Federation, and North America give rise to some of the lowest hydrogen production costs. Gas importers such as Japan, Korea, China and India have to contend with higher gas import prices, and that makes for higher hydrogen production costs.

Figure 9. Hydrogen production costs using natural gas in different regions, 2018



Notes: kgH_2 = kilogram of hydrogen; OPEX = operational expenditure. CAPEX in 2018: SMR without CCUS = USD 500–900 per kilowatt hydrogen (kW_{H2}), SMR with CCUS = USD 900–1 600/kW_{H2}, with ranges due to regional differences. Gas price = USD 3–11 per million British thermal units (MBtu) depending on the region. More information on the underlying assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

Availability of low-cost gas is a crucial cost determinant for SMR-based hydrogen.

Adding CCUS to SMR plants leads, on average, to cost increases of some 50% for CAPEX and some 10% for fuel, with the exact amounts depending on the design. It also leads on average to a doubling of OPEX as a result of CO_2 transport and storage costs. In the most promising regions, however, costs for hydrogen from SMR with CCUS are in the range of USD 1.4–1.5/kgH_2, making it one of the lowest cost low-carbon hydrogen production routes (see section "Comparison between alternative hydrogen production pathways" in this chapter.for a comparison with other production technologies).

Hydrogen from water and electricity

Water electrolysis is an electrochemical process that splits water into hydrogen and oxygen. Less than 0.1% of dedicated hydrogen production globally comes from water electrolysis today, and the hydrogen produced by this means is mostly used in markets where high-purity hydrogen is necessary (for example, electronics and polysilicon). In addition to the hydrogen produced through water electrolysis, around 2% of total global hydrogen is created as a by-product of chlor-alkali electrolysis in the production of chlorine and caustic soda.

With declining costs for renewable electricity, in particular from solar PV and wind, interest is growing in electrolytic hydrogen (Chapter 4) and there have been several demonstration projects in recent years. The efficiency of electrolyser systems today ranges between 60% and 81% depending on the technology type and load factor. Producing all of today's dedicated hydrogen output (69 MtH_2) from electricity would result in an electricity demand of 3 600 terawatt hours (TWh), more than the total annual electricity generation of the European Union.

Electrolysis requires water as well as electricity. Around 9 litres of water are needed to produce 1 kgH_2,[9] producing 8 kilograms (kg) of oxygen as a by-product, which at smaller scale can be used in the health care sector or at a larger scale for industrial purposes. If all of today's dedicated hydrogen production of around 70 MtH_2 were to be produced by electrolysis, this would result in a water demand of 617 million cubic metres (m^3), which would correspond to 1.3% of the water consumption of the global energy sector today (IEA, 2016) or roughly twice the current water consumption for hydrogen from SMR (345 million m^3 of water for 52 MtH_2 from SMR).

Freshwater access can be an issue in water-stressed areas. Using seawater could become an alternative in coastal areas. Using reverse osmosis for desalination requires an electricity demand of 3–4 kilowatt hours (kWh) per m^3 of water and costs around USD 0.7–2.5 per m^3 of water (Tractebel, 2018; Caldera et al., 2018). This has only a minor impact on the total costs of water electrolysis, increasing total hydrogen production costs by USD 0.01–0.02/kgH_2. Direct use of seawater in electrolysis currently leads to corrosive damage and to the production of chlorine, but research is looking at how to make it easier to use seawater in electrolysis in the future.

Technology options

Three main electrolyser technologies exist today: alkaline electrolysis, proton exchange membrane (PEM) electrolysis, and solid oxide electrolysis cells (SOECs). Their main technical and economic characteristics are summarised in Table 3.

Alkaline electrolysis is a mature and commercial technology. It has been used since the 1920s, in particular for hydrogen production in the fertiliser and chlorine industries. The operating range of alkaline electrolysers goes from a minimum load of 10% to full design capacity. Several alkaline electrolysers with a capacity of up to 165 megawatts electrical (MW_e) were built in the last century in countries with large hydropower resources (Canada, Egypt, India, Norway and Zimbabwe), although almost all of them were decommissioned when natural gas and steam methane reforming for hydrogen production took off in the 1970s. Alkaline electrolysis is characterised by relatively low capital costs compared to other electrolyser technologies due to the avoidance of precious materials.

PEM electrolyser systems were first introduced in the 1960s by General Electric to overcome some of the operational drawbacks of alkaline electrolysers. They use pure water as an electrolyte solution, and so avoid the recovery and recycling of the potassium hydroxide electrolyte solution that is necessary with alkaline electrolysers. They are relatively small,

[9] For comparison, SMR without CCUS requires around 7 litres of raw water per kgH_2 (IEAGHG, 2017b).

making them potentially more attractive than alkaline electrolysers in dense urban areas. They are able to produce highly compressed hydrogen for decentralised production and storage at refuelling stations (30–60 bar without an additional compressor and up to 100–200 bar in some systems, compared to 1–30 bar for alkaline electrolysers) and offer flexible operation, including the capability to provide frequency reserve and other grid services. Their operating range can go from zero load to 160% of design capacity (so it is possible to overload the electrolyser for some time, if the plant and power electronics have been designed accordingly). Against this, however, they need expensive electrode catalysts (platinum, iridium) and membrane materials, and their lifetime is currently shorter than that of alkaline electrolysers. Their overall costs are currently higher than those of alkaline electrolysers, and they are less widely deployed.

SOECs are the least developed electrolysis technology. They have not yet been commercialised, although individual companies are now aiming to bring them to market. SOECs use ceramics as the electrolyte and have low material costs. They operate at high temperatures and with a high degree of electrical efficiency. Because they use steam for electrolysis, they need a heat source. If the hydrogen produced were to be used for the production of synthetic hydrocarbons (power-to-liquid and power-to-gas), the waste heat from these synthesis processes (e.g. Fischer-Tropsch synthesis, methanation) could be recovered to produce steam for further SOEC electrolysis. Nuclear power plants, solar thermal or geothermal heat systems could also be heat sources for high-temperature electrolysis (Box 4).

Unlike alkaline and PEM electrolysers, it is possible to operate an SOEC electrolyser in reverse mode as a fuel cell, converting hydrogen back into electricity, which means it could provide balancing services to the grid in combination with hydrogen storage facilities. This would increase the overall utilisation rate of the equipment. It is also possible to use a SOEC electrolyser for co-electrolysis of steam and carbon dioxide, producing a gas mixture (carbon monoxide and hydrogen) for subsequent conversion to a synthetic fuel. One key challenge for those developing SOEC electrolysers is addressing the degradation of materials that results from the high operating temperatures.

Table 3. Techno-economic characteristics of different electrolyser technologies

	Alkaline electrolyser			PEM electrolyser			SOEC electrolyser		
	Today	2030	Long term	Today	2030	Long-term	Today	2030	Long term
Electrical efficiency (%, LHV)	63–70	65–71	70–80	56–60	63–68	67–74	74–81	77–84	77–90
Operating pressure (bar)	1–30			30–80			1		
Operating temperature (°C)	60–80			50–80			650 – 1 000		
Stack lifetime (operating hours)	60 000 – 90 000	90 000 – 100 000	100 000 – 150 000	30 000 – 90 000	60 000 – 90 000	100 000 – 150 000	10 000 – 30 000	40 000 – 60 000	75 000 – 100 00
Load range (%, relative to nominal load)	10–110			0–160			20–100		
Plant footprint (m^2/kW_e)	0.095			0.048					

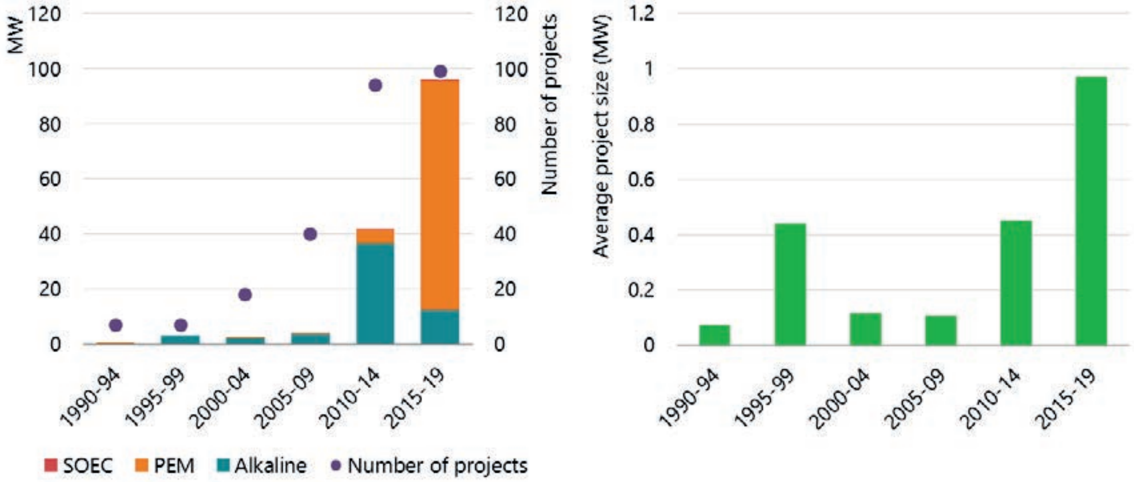
	Alkaline electrolyser			PEM electrolyser			SOEC electrolyser		
	Today	2030	Long term	Today	2030	Long-term	Today	2030	Long term
Electrical efficiency (%, LHV)	63–70	65–71	70–80	56–60	63–68	67–74	74–81	77–84	77–90
CAPEX (USD/kW$_e$)	500 – 1400	400 – 850	200 – 700	1 100 – 1 800	650 – 1 500	200 – 900	2 800 – 5 600	800 – 2 800	500 – 1 000

Notes: LHV = lower heating value; m^2/kW$_e$ = square metre per kilowatt electrical. No projections made for future operating pressure and temperature or load range characteristics. For SOEC, electrical efficiency does not include the energy for steam generation. CAPEX represents system costs, including power electronics, gas conditioning and balance of plant; CAPEX ranges reflect different system sizes and uncertainties in future estimates.

Sources: Buttler and Spliethoff (2018), "Current status of water electrolysis for energy storage, grid balancing and sector coupling via power-to-gas and power-to-liquids: a review"; Agora Verkehrswende, Agora Energiewende and Frontier Economics (2018), *The Future Cost of Electricity-Based Synthetic Fuels*; NOW (2018), *Studie IndWEDe Industrialisierung der Wasserelektrolyse in Deutschland: Chancen und Herausforderungen für nachhaltigen Wasserstoff für Verkehr, Strom und Wärme*; Schmidt et al. (2017), "Future cost and performance of water electrolysis: An expert elicitation study"; FCH JU (2014), *Development of Water Electrolysis in the European Union, Final Report*; Element Energy (2018), "Hydrogen supply chain evidence base".

There has been an increase in new electrolysis installations over the last decade aimed at producing hydrogen from water, with PEM technology making significant inroads into the market. Geographically most of the projects are in Europe, although projects have also been started or announced in Australia, China and the Americas. The average unit size of these electrolyser additions has increased in recent years from 0.1 MW$_e$ in 2000–09 to 1.0 MW$_e$ in 2015–19, indicating a shift from small pilot and demonstration projects to commercial-scale applications. This should start to create economies of scale that will help to drive down capital costs and to scale up the supply chain of the electrolyser industry (Figure 10). Several projects under development have electrolyser sizes of 10 MW$_e$ or above, and some projects with electrolyser sizes of 100 MW$_e$ or larger are now under discussion.

Figure 10. Development of electrolyser capacity additions for energy purposes and their average unit size, 1990–2019



Note: Capacity additions refer to already installed capacity additions and are cumulated over the specified 5-year periods.

Sources: IEA analysis based on Chehade et al. (2019), "Review and analysis of demonstration projects on Power-to-X pathways in the world", IEA (2018), *World Energy Investment*, and the World Energy Council (2018), "Hydrogen an enabler of the Grand Transition" and data provided by IEA Hydrogen Technology Collaboration Programme.

Global electrolyser capacity additions for energy purposes have been growing rapidly in recent years, and installations have been growing in size, providing cost reductions from economies of scale and learning effects.

Box 4. Thermal routes for hydrogen production – a case for nuclear?

Heat can be used in various ways in the production of hydrogen. Heat in form of steam is required in the process of steam methane reforming. The electricity consumption of water electrolysis can be reduced by not electrolysing liquid water, but steam, so shifting part of the required energy for the electrolysis from electrical to thermal energy. SOEC is an example of such a high-temperature electrolysis. This means that there is a lot of interest in the scope for integrating heat into hydrogen production and how best to source heat requirements. Potential opportunities exist for places where low-cost heat is available, whether this comes from sources such as waste heat from industrial processes, or from geothermal or solar heat in regions with good resources.

Nuclear power plants are another option for the provision of heat for hydrogen production. They could, for example, provide steam for natural gas-based steam methane reforming. Depending on local conditions, using steam from nuclear power could be cheaper than using steam from natural gas, as well as reducing the carbon intensity of the hydrogen produced. It could also provide a useful additional revenue stream for nuclear power plants.

Electricity and heat (produced at temperature levels of around 300°C by nuclear power plants) could also be used to provide electricity and steam for SOEC electrolysis. Research is underway to develop materials for SOEC electrolysis that are well suited to the temperature levels of nuclear energy heat sources (US-DOE, 2018).

Small modular reactors could also have a role to play in SOEC electrolysis in the future. Six small modular reactors with a combined capacity of 300 MW_e could, for example, meet the annual hydrogen demand of a mid-sized ammonia plant (73 000 tonnes of hydrogen per year [tH_2/yr]). Exploring non-electric applications for small modular reactors, such as hydrogen, is part of the Joint Use Modular Plant (JUMP) research programme in the United States.

In the longer term, advanced nuclear reactors, such as the two industrial prototype high-temperature pebble-bed reactors currently being constructed in China, could also become the heat source for thermochemical water splitting, with some reactor designs having coolant outlet temperatures of 800–1 000°C.

Source: US-DOE (2018), "Energy Department announces up to $3.5m for nuclear-compatible hydrogen production".

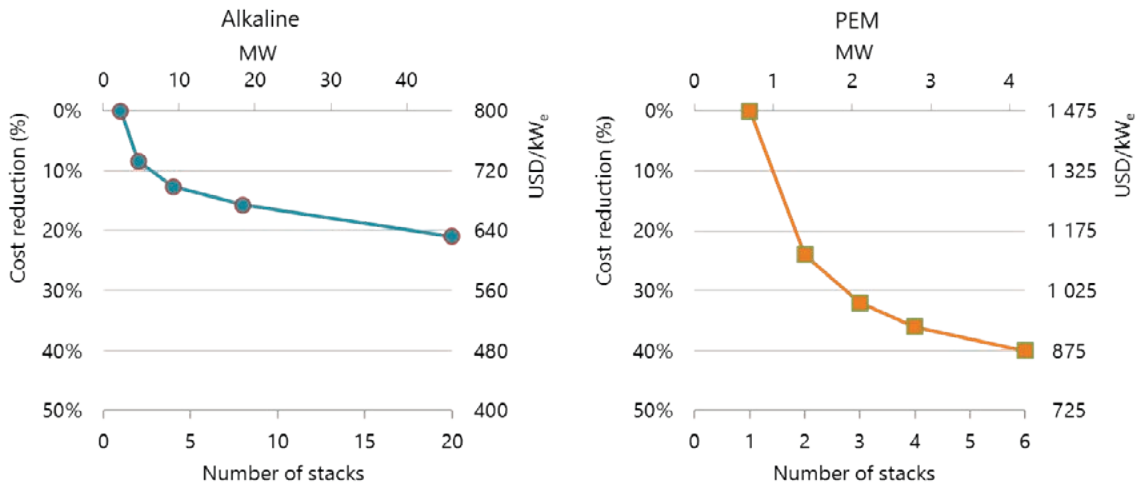
Costs of hydrogen production from water and electricity

The production costs of hydrogen from water electrolysis are influenced by various technical and economic factors, with CAPEX requirements, conversion efficiency, electricity costs and annual operating hours being the most important.

CAPEX requirements are today in the range of USD 500–1 400/kW_e for alkaline electrolysers and USD 1 100–1 800/kW_e for PEM electrolysers, while estimates for SOEC electrolysers range across USD 2 800–5 600/kW_e (Table 3). The electrolyser stack is responsible for 50% and 60% of the CAPEX costs of alkaline and PEM electrolysers respectively. The power electronics, gas-conditioning and plant components account for most of the rest of the costs.

Future cost reductions will be influenced by innovations in the technologies themselves, (for example the development of less costly materials for electrodes and membranes), and by economies of scale in the manufacturing processes (for example by the development of larger electrolysers). Figure 11 illustrates the potential for cost reduction in current alkaline and PEM electrolysers from switching to larger multi-stack systems (combining several electrolyser stacks to increase the overall capacity of the electrolyser system).

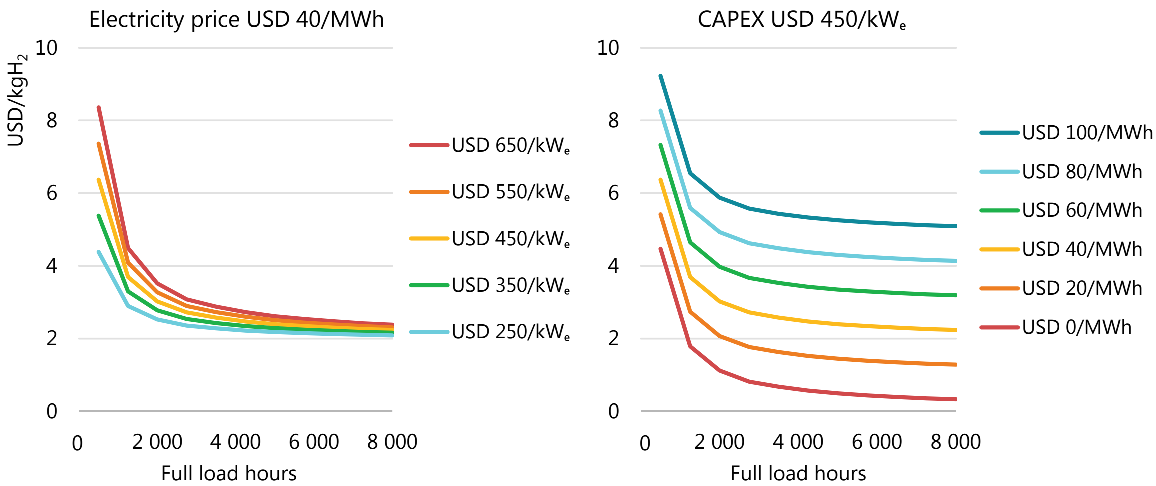
Figure 11. Expected reduction in electrolyser CAPEX from the use of multi-stack systems



Notes: Based on a single stack size of 2 MW for alkaline electrolysis and 0.7 MW for PEM electrolysis.
Source: Based on analysis supported by Task 38 of the IEA Hydrogen Technology Collaboration Programme and published in Proost (2018), "State-of-the art CAPEX data for water electrolysers, and their impact on renewable hydrogen price settings".

Scaled-up electrolysers and automated production processes are leading to significant CAPEX reductions.

Figure 12. Future levelised cost of hydrogen production by operating hour for different electrolyser investment costs (left) and electricity costs (right)



Notes: MWh = megawatt hour. Based on an electrolyser efficiency of 69% (LHV) and a discount rate of 8%.

Source: IEA 2019. All rights reserved.

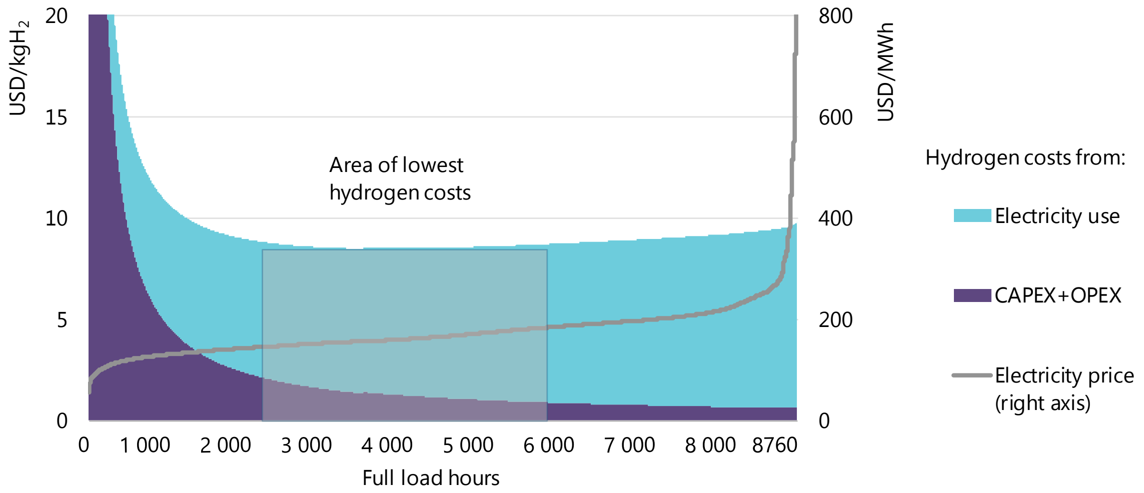
With increasing full load hours, the impact of CAPEX on hydrogen costs declines and the electricity becomes the main cost component for water electrolysis.

As electrolyser operating hours increase, the impact of CAPEX costs on the levelised cost of hydrogen declines and the impact of electricity costs rises (Figure 12). Low-cost electricity available at a level to ensure the electrolyser can operate at relatively high full load hours is therefore essential for the production of low-cost hydrogen.[10]

In electricity systems with increasing shares of variable renewables, surplus electricity may be available at low cost. Producing hydrogen through electrolysis and storing the hydrogen for later use could be one way to take advantage of this surplus electricity, but if surplus electricity is only available on an occasional basis it is unlikely to make sense to rely on it to keep costs down. Running the electrolyser at high full load hours and paying for the additional electricity can actually be cheaper than just relying on surplus electricity with low full load hours.

The relationship between electricity costs and operating hours becomes apparent when looking at electrolysers that use grid electricity for hydrogen production (Figure 13). Very low-cost electricity is generally available only for a very few hours within a year, which implies a low utilisation of the electrolyser and high hydrogen costs that reflect CAPEX costs. With increasing hours, electricity costs increase, but the higher utilisation of the electrolyser leads to a decline in the cost of producing a unit of hydrogen up to an optimum level at around 3 000–6 000 equivalent full load hours. Beyond that, higher electricity prices during peak hours lead to an increase in hydrogen unit production costs.

Figure 13. Hydrogen costs from electrolysis using grid electricity



Notes: CAPEX = USD 800/kW$_e$; efficiency (LHV) = 64%; discount rate = 8%.
Source: IEA analysis based on Japanese electricity spot prices in 2018, JEPX (2019), *Intraday Market Trading Results 2018*.

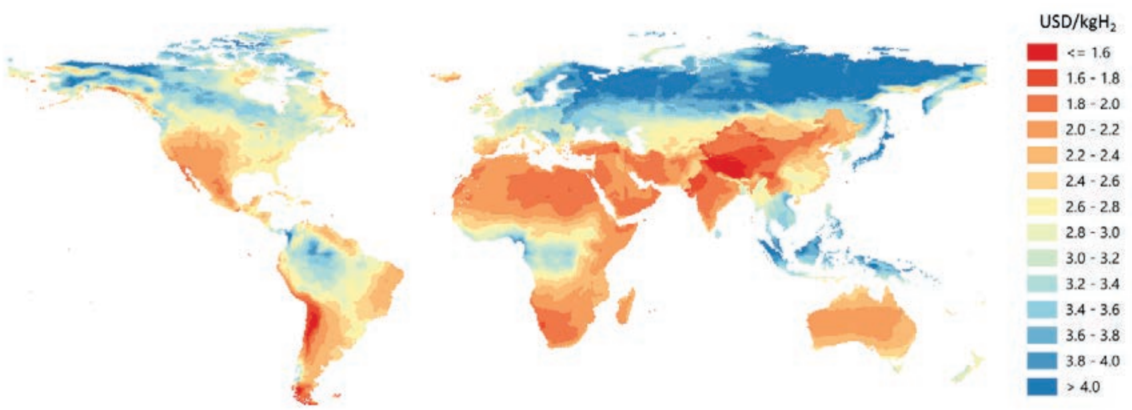
Higher utilisation rates help to reduce the impact of CAPEX, but for grid-connected electrolysers this means higher electricity prices; the lowest hydrogen costs are achieved in mid-load operation.

[10] Full load hours are an indicator of the annual utilisation of an electrolyser. Full load hours represent the number of hours within a year the electrolyser would have to run at its design capacity, i.e. at "full load", to achieve a certain annual output. Full load hours of 8 760 h represent the maximum possible utilisation, meaning that the electrolyser would be running for all hours within a year at its design capacity. From given full load hours and electrolyser capacity, the annual hydrogen production can be calculated (taking into account the conversion efficiency, as the electrolyser capacity is typically measured in electricity input terms).

Dedicated electricity generation from renewables or nuclear power offers an alternative to the use of grid electricity for hydrogen production. With declining costs for solar PV and wind generation, building electrolysers at locations with excellent renewable resource conditions could become a low-cost supply option for hydrogen, even after taking into account the transmission and distribution costs of transporting hydrogen from (often remote) renewables locations to the end users, as discussed in Chapter 3.

Promising areas exist, for example, in Patagonia, New Zealand, Northern Africa, the Middle East, Mongolia, most of Australia, and parts of China and the United States (Figure 14). The Asian Renewable Energy Hub project site in Western Australia aims to build 7.5 gigawatts (GW) of wind generation and 3.5 GW of solar generation, with around 8 GW of the generation being dedicated to hydrogen production for domestic use and for export (Asian Renewable Energy Hub, 2019). Several other projects to produce hydrogen from dedicated renewable resources in various parts of the world are in preparation or have been announced. In areas where both resources are excellent, combining solar PV and onshore wind in a hybrid plant has the potential to lower costs further.

Figure 14. Hydrogen costs from hybrid solar PV and onshore wind systems in the long term



Notes: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area. Electrolyser CAPEX = USD 450/kW$_e$, efficiency (LHV) = 74%; solar PV CAPEX and onshore wind CAPEX = between USD 400–1 000/kW and USD 900–2 500/kW depending on the region; discount rate = 8%.

Source: IEA analysis based on wind data from Rife et al. (2014), *NCAR Global Climate Four-Dimensional Data Assimilation (CFDDA) Hourly 40 km Reanalysis* and solar data from renewables.ninja (2019).

The declining costs of solar PV and wind could make them a low-cost source for hydrogen production in regions with favourable resource conditions.

Hydrogen from coal

Hydrogen production from coal using gasification is a well-established technology, used for many decades by the chemical and fertiliser industries for the production of ammonia (especially in China). Globally around 130 coal gasification plants in operation, more than 80% of which are in China. Hydrogen production using coal produces CO_2 emissions of about 19 tCO_2/tH_2, which is twice as much as natural gas.

Technology options

The high CO_2 emissions intensity of coal-based hydrogen means that carbon capture technology will need to be used if hydrogen from coal is to have a future in a low-carbon energy system. The use of CCUS brings some challenges: coal produces hydrogen with a relatively low hydrogen-to-carbon ratio (hydrogen to carbon ratio of 0.1:1 from coal vs. 4:1 from methane) and brings with it a high level of impurities in the feedstock (sulphur, nitrogen and minerals) (Muradov, 2017).

The synthesis gas obtained from the gasification of coal could be used to fuel a combined-cycle power plant and – assuming the coal gasification plant was equipped with CCUS – the electricity it generated would count as low carbon. If an additional water-gas-shift (WGS) unit could be added, the synthesis gas could also be used to produce more hydrogen, allowing the coal gasification plant to shift between the production of electricity and hydrogen according to which is more profitable. Currently, however, there are no large-scale commercial units producing both hydrogen and electricity.

The performance of individual CO_2 capture technologies and methods for integrating them differ in terms of CO_2 removal rate as well as hydrogen and CO_2 purity levels. Hydrogen purity requirements vary strongly by end-use application. While most fuel cells require high purity levels, lower levels suffice for gas turbines, refinery processes and industrial boilers. Few technologies exist that produce both high-purity hydrogen and CO_2 that is pure enough for other uses or storage, since gas separation technologies focus on either hydrogen removal or CO_2 removal. The optimal combination of hydrogen production route and capture technology therefore depends on what the hydrogen is going to be used for, as well as on the production costs.

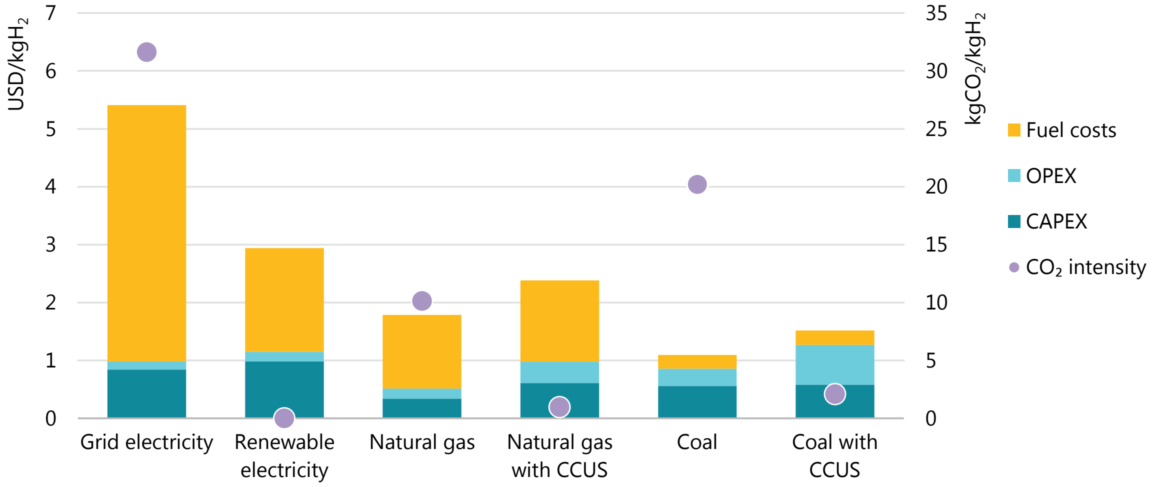
The vast majority of hydrogen production from coal currently takes place in China using coal gasification, mainly to produce ammonia. China is exploring the role of hydrogen in its economy, and using coal is currently the cheapest way of producing it, with costs amounting to RMB 0.6–0.7/m^3 (about USD 1/kgH_2). CHN Energy, China's largest power company, is also the world's largest hydrogen production company. Its 80 coal gasifiers can produce around 8 MtH_2/yr, which is equivalent to 12% of global dedicated hydrogen production today. Using coal with CCUS currently looks likely to be the lowest-cost way of producing cleaner hydrogen in China, but current technologies enable a CO_2 intensity only as low as 2 kilograms of carbon dioxide per kilogram of hydrogen ($kgCO_2/kgH_2$) while advanced technologies may permit this to reach as low as 0.4 $kgCO_2/kgH_2$ (Figure 15).

In Australia the Hydrogen Energy Supply Chain (HESC) Latrobe Valley project is seeking to produce hydrogen from lignite using high-pressure partial oxidation. The related CarbonNet Carbon Capture and Storage Project presents a potential solution for mitigating CO_2 separated from the hydrogen production process in the commercial phase. The hydrogen produced would be liquefied and exported to Japan. The first step is a one-year pilot project to treat 160 tonnes of lignite to produce 3 tH_2.

Costs of hydrogen production from coal

CAPEX requirements account for around 50% of the cost of producing hydrogen from coal, and fuel accounts for a further 15–20% (Figure 15). The availability and cost of coal therefore plays an important role in determining the viability of coal-based hydrogen projects.

Figure 15. Hydrogen production costs in China today



Notes: CAPEX of coal with CCUS = USD 1 475/kW$_{H_2}$. Renewable electricity costs = USD 30/MWh at 4 000 full load hours. More information on the underlying assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

Coal-based hydrogen with CCUS is likely to remain the lowest-cost clean hydrogen production route in China for the near term.

Reducing the carbon footprint will be a critical factor for the prospects of coal-based hydrogen in a low-carbon context. Adding CCUS to coal-based hydrogen production is expected to increase CAPEX and fuel costs by 5% and OPEX by 130%. In China and India, with their established coal mining infrastructure and the lack of availability of cheap domestic natural gas, coal-based hydrogen equipped with CCUS is likely to be at least in the medium term the cheapest option for clean hydrogen production.

Hydrogen from biomass

Hydrogen can be produced from biomass in different ways. In biochemical routes, microorganisms work on organic material to produce biogas (a process referred to as anaerobic digestion) or a combination of acids, alcohols and gases (fermentation). Thermochemical gasification of biomass is a process that works much like coal gasification to convert biomass to a mix of carbon monoxide, CO_2, hydrogen and methane. Anaerobic digestion to produce biogas is the most technically mature of these processes, but can only process sewage sludge, agricultural, food processing and household waste, and some energy crops. Fermentation can process the non-edible cellulosic part of some plants. Gasification could potentially convert all organic matter, and in particular the lignin component of biomass. Although there are a number of biomass gasification demonstration plants in the world, the technology is not yet fully developed, and the problem of the formation of tars that may cause catalyst poisoning has not been fully resolved yet (Ericsson, 2017). In all cases, the produced gas would need to be further processed to extract hydrogen.

The complex processing of biomass means that it is generally a more expensive way of producing low-carbon hydrogen than solar- or wind-based electrolysis. The potential for large-scale biomass-based hydrogen production is also be limited by the availability of cheap biomass. For example, satisfying a theoretical hydrogen demand of 60 MtH$_2$ in the US market –

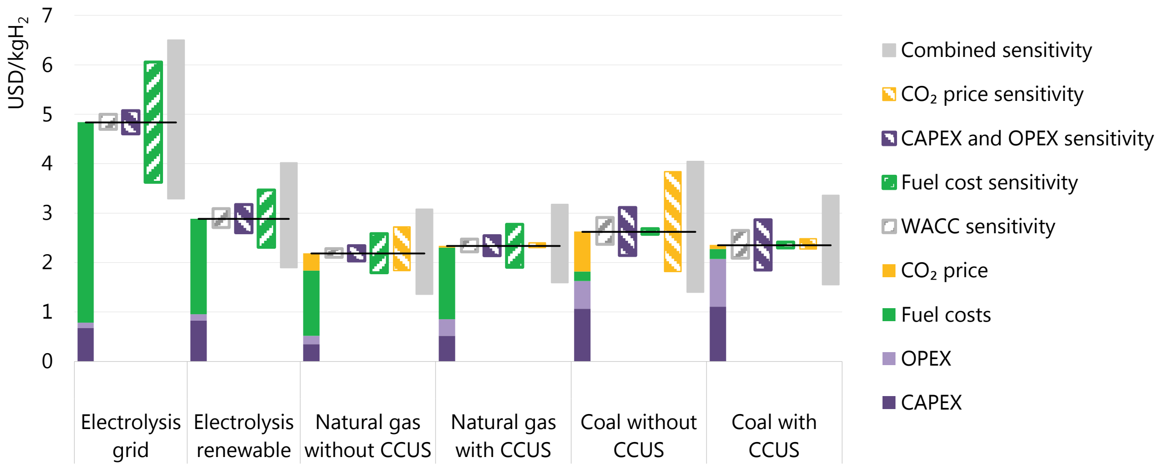
corresponding to four times the United States' current hydrogen demand – would require almost 100% of its technical biomass potential, but only 6% of its wind power, and less than 1% of its solar power potential (Ruth, Jadun and Pivovar, 2017). Combining hydrogen production from biomass with carbon capture and storage could, however, be an option to create so-called "negative emissions", which may have a role to play in the future.[11]

Comparison between alternative hydrogen production pathways

In the near term – that is, until 2030 – the cost advantage of fossil fuels is likely to continue in most places, with hydrogen from natural gas without CCUS costing in the range of USD 1–2/kgH$_2$, depending on local gas prices.[12]

Except in the case of hydrogen produced from coal, fuel costs are the biggest single component of hydrogen production costs (Figure 16). Future hydrogen costs will therefore largely be influenced by electricity and gas costs, or parameters influencing these costs such as conversion efficiencies. Electrolysis production costs can also be sensitive to CAPEX requirements, in particular if plants are operating at low full load hours.

Figure 16. Hydrogen production costs for different technology options, 2030



Notes: WACC = weighted average cost of capital. Assumptions refer to Europe in 2030. Renewable electricity price = USD 40/MWh at 4 000 full load hours at best locations; sensitivity analysis based on +/-30% variation in CAPEX, OPEX and fuel costs; +/-3% change in default WACC of 8% and a variation in default CO$_2$ price of USD 40/tCO$_2$ to USD 0/tCO$_2$ and USD 100/tCO$_2$. More information on the underlying assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

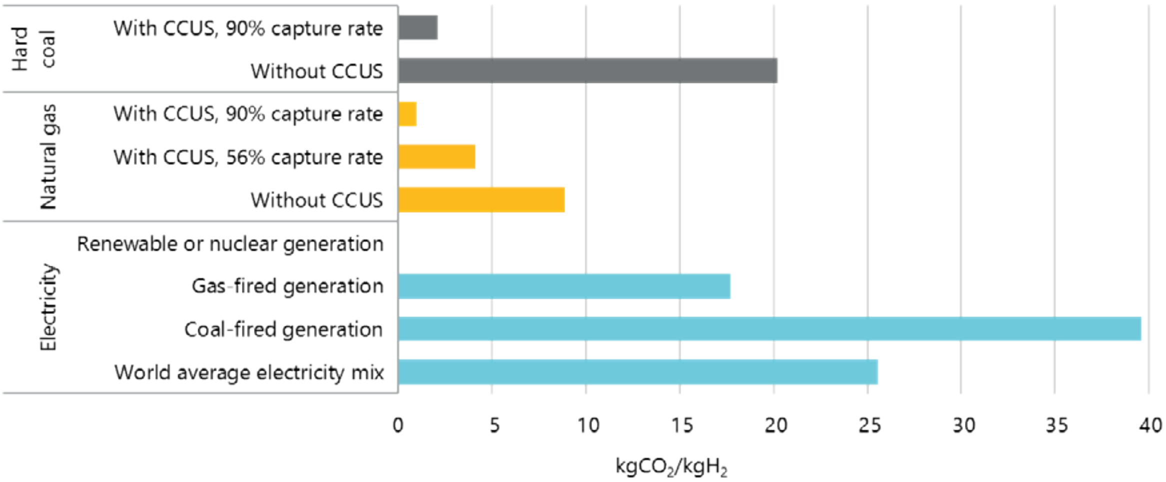
In the near term, hydrogen production from fossil fuels will remain the most cost-competitive option in most cases.

[11] By combining the use of bioenergy and CCUS, CO$_2$ formed during bioenergy conversion processes can be captured and injected into long-term geological storage. This provides the possibility to effectively remove CO$_2$ from the atmosphere while producing energy.

[12] Just taking into account the LHV energy content of 1 kgH$_2$, i.e. ignoring any later uses of hydrogen, a cost of USD 1/kgH$_2$ corresponds to USD 30/MWh, or in barrels of oil equivalent to almost USD 50 per barrel (bbl).

The CO_2 impact of different hydrogen production technologies varies widely (Figure 17). The carbon intensity of hydrogen from natural gas without CCUS is roughly half that of coal without CCUS. The CO_2 intensity of electrolysis depends on the CO_2 intensity of the electricity input. The conversion losses during electricity generation mean that using electricity from natural gas or coal power plants would result in higher CO_2 intensities than directly using natural gas or coal for hydrogen production. This means that for electrolysis to have the same or lower CO_2 intensity as hydrogen production from natural gas without CCUS, the CO_2 intensity of electricity has to be below 185 grams of carbon dioxide per kilowatt hour (gCO_2/kWh), just above half the emissions of a modern combined-cycle gas power plant.

Figure 17. CO_2 intensity of hydrogen production



Notes: Capture rate of 56% for natural gas with CCUS refers to capturing only the feedstock-related CO_2, whereas for 90% capture rate CCUS is also applied to the fuel-related CO_2 emissions; CO_2 intensities of electricity taking into account only direct CO_2 emissions at the electricity generation plant: world average 2017 = 491 gCO_2/kWh, gas-fired power generation = 336 gCO_2/kWh, coal-fired power generation = 760 gCO_2/kWh. The CO_2 intensities for hydrogen also do not include CO_2 emissions linked to the transmission and distribution of hydrogen to the end users, e.g. from grid electricity used for hydrogen compression. More information on the underlying assumptions is available at www.iea.org/hydrogen2019.

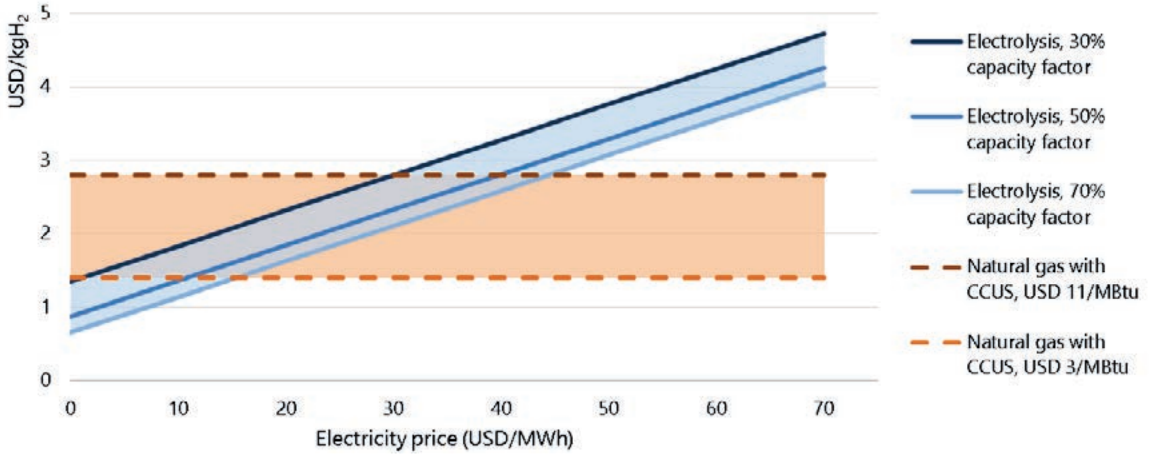
Source: IEA 2019. All rights reserved.

The CO_2 intensity of hydrogen directly from natural gas is half of that from coal and nearly half that from gas-fired electricity; the CO_2 intensity of electrolysis depends on the CO_2 intensity of the electricity.

Low-carbon hydrogen produced with CCUS or from renewable electricity is in most cases currently more costly than hydrogen generated from unabated fossil fuels. The cost of hydrogen produced from natural gas is generally around USD 1.5–3/kgH_2, while for hydrogen generated from renewable electricity (solar PV or onshore wind) it is generally around USD 2.5–6/kgH_2. Making hydrogen from natural gas with CCUS in the Middle East competitive with unabated fossil fuel hydrogen production would require a CO_2 price of around USD 50/tCO_2, or an equivalent cost benefit for the CCUS option.

The future competitiveness of low-carbon hydrogen produced from natural gas with CCUS or from renewable electricity (from solar PV or onshore wind) mainly depends on gas and electricity prices. At low gas prices, renewable electricity must reach a cost range below USD 10/MWh for electrolysis to become cost-competitive with natural gas with CCUS. Higher gas prices would make higher-cost renewable electricity cost-competitive: at a gas price of USD 11/MBtu, renewable electricity would be competitive at up to around USD 30–45/MWh (Figure 18).

Figure 18. Comparison of hydrogen production costs from electricity and natural gas with CCUS in the near term



Notes: More information on the underlying assumptions is available at www.iea.org/hydrogen2019.
Source: IEA 2019. All rights reserved.

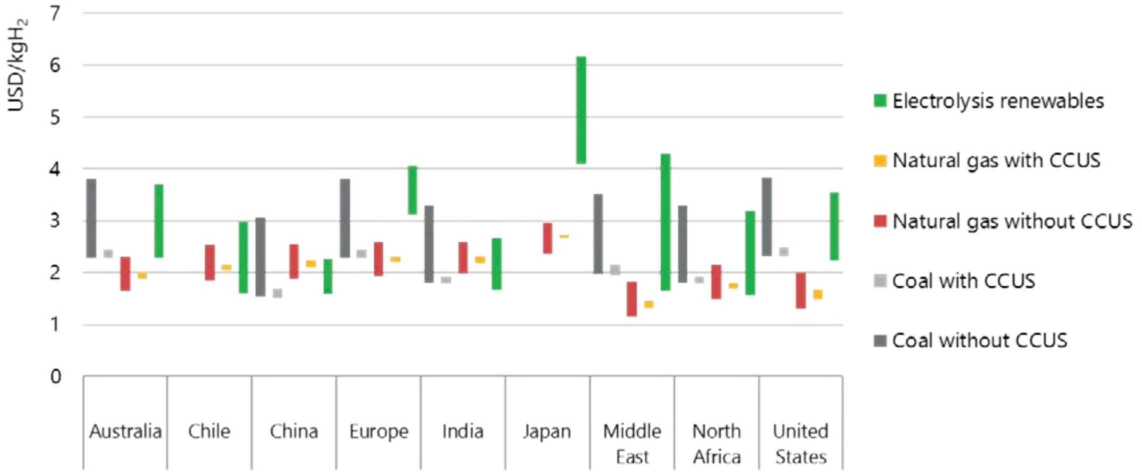
Depending on local gas prices, electricity at USD 10- 40/MWh and at full load hours of around 4 000 hours are needed for water electrolysis to become cost-competitive with natural gas with CCUS.

The impact of renewable electricity and gas costs on hydrogen production costs becomes apparent when looking at specific countries (Figure 19). In countries with good renewable resources, but dependent on natural gas imports, in particular in the form of liquefied natural gas, producing hydrogen from renewables may be cheaper than producing it from natural gas, while production from natural gas with CCUS may be the cheaper option in regions with cheap domestic gas resources and CO_2 storage availability.

Other factors are also relevant to the choice between alternative low-carbon hydrogen production options. For hydrogen production from fossil fuels in combination with CO_2 storage, the geological availability and public acceptance of CO_2 storage are prerequisites. For water electrolysis, access to adequate supplies of water is a prerequisite, even if the costs for water treatment (e.g. seawater desalination) are only a small fraction of the total hydrogen production costs. Countries could also consider importing hydrogen or hydrogen-based products if they are available at a lower price than domestic alternatives, as discussed in more detail in Chapter 3.

From an investment viewpoint, the scale of investment is also relevant. While CCUS plants require a certain scale to justify the investment in CO_2 transport and storage infrastructure, electrolysers operate at a smaller scale using more modular technology, which can be gradually expanded and adjusted to demand. For example, the H21 North of England project in the UK plans to produce hydrogen from twelve ATR units with CCUS, each with a capacity of around 1 350 MW_{H2} and requiring an investment of around USD 945 million per unit, whereas the largest electrolyser module offered today is 20 MW_e (14 MW_{H2}), requiring investment of around USD 18 million (or USD 280 million for 220 MW_{H2}).

Figure 19. Hydrogen production costs in different parts of the world



Notes: Bars indicate range between near- and long-term hydrogen production costs, which include a CO_2 price of USD 25/t CO_2 in the near term and USD 100/tCO_2 in the long term. For options from coal and natural gas, the higher value indicates the long-term costs (due to the increasing CO_2 price), whereas for hydrogen from renewable electricity the lower value indicates the long-term costs.

Source: IEA 2019. All rights reserved.

In countries relying on gas imports and characterised by good renewable resources, clean hydrogen production from renewable electricity can compete effectively with production that relies on natural gas.

Converting hydrogen to hydrogen-based fuels and feedstocks that are easier to store, transport and use

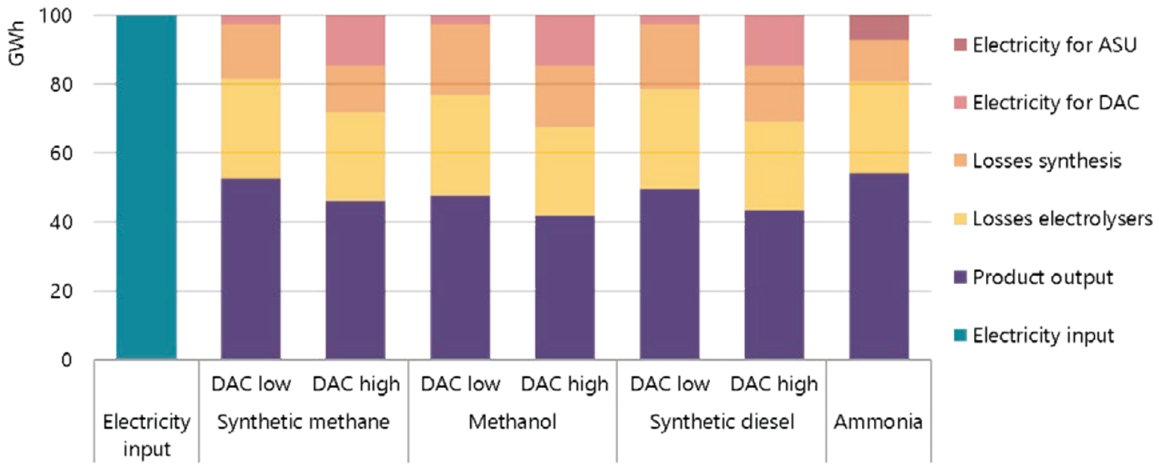
Hydrogen has low energy density, which makes it more challenging to store and transport than fossil fuels. However, it can be converted into hydrogen-based fuels and feedstocks, such as synthetic methane, synthetic liquid fuels and ammonia, which can make use of existing infrastructure for their transport, storage and distribution. This can reduce the costs of reaching final users. Some of the synthetic hydrocarbons produced from hydrogen can be direct substitutes for their fossil equivalents. Ammonia is already used today as a feedstock in the chemical industry (see Chapter 4) and could be a hydrogen carrier for the long-distance transport of hydrogen in the future (see Chapter 3), or itself be used as fuel in the shipping sector (see Chapter 5).

The potential benefits and opportunities of these hydrogen-based fuels and feedstocks have to be weighed, however, against the costs of converting hydrogen into these products. Many of the technology pathways to produce these fuels and feedstocks are at an early demonstration stage, resulting in high costs. Producing ammonia requires the separation of nitrogen from the air, while the production of synthetic hydrocarbons requires carbon as an input, which has implications for the cost of production, while the origin of the carbon also affects the environmental impact and the carbon intensity of the synthetic hydrocarbon.

Technology options

Various pathways exist to convert hydrogen into fuels and feedstocks that can be more easily handled, transported and used. Ammonia can be produced by combining hydrogen and nitrogen, and synthetic hydrocarbons, such as methane, methanol, diesel or jet fuel, can be produced by combining hydrogen with carbon in the form of CO_2. However, for pathways based on electrolytic hydrogen, much of the electricity used to convert hydrogen into fuels and feedstocks is lost during the process of conversion (Figure 20).

Figure 20. Outputs and losses of different pathways for hydrogen-based fuels and feedstocks from electrolytic hydrogen



Notes: ASU = air separation unit (for nitrogen production); DAC = direct air capture; GWh = gigawatt hour. The energy contents of the outputs (methane, methanol, diesel and ammonia) are based on their LHVs. For methane, methanol and diesel, DAC has been assumed here as the source of CO_2 feedstocks, with electricity needs of 250 kWh per tCO_2 for low-temperature DAC (DAC low) and 1 750 kWh per tCO_2 for high-temperature DAC (DAC high). Low-temperature DAC also requires heat of 1 535 kWh per tCO_2, which could be covered in large part by the shown synthesis heat losses.

Source: IEA 2019. All rights reserved.

Around 45–60% of the electricity used for the production of synthetic hydrocarbons or ammonia is lost during the process.

Ammonia

Ammonia is a compound of nitrogen and hydrogen and therefore does not generate CO_2 emissions when combusted. It is a gas at normal temperature and pressure, but can be liquefied at -33°C, a temperature that is not too difficult to reach. Liquid ammonia has a 50% higher volumetric energy density than liquid hydrogen. Ammonia has been used as a refrigerant for 170 years, and as a chemical feedstock for nitrogen fertilisers and explosives for a century. Industry is used to storing and transporting it, including in oceangoing tankers. Ammonia can, in principle, be used as a fuel in various energy applications (e.g. for co-firing in coal power plants), but none of these applications is being commercially used today. The toxicity of ammonia means that its handling requires care and would likely be limited to professionally trained operators, potentially restricting its techno-economic potential.

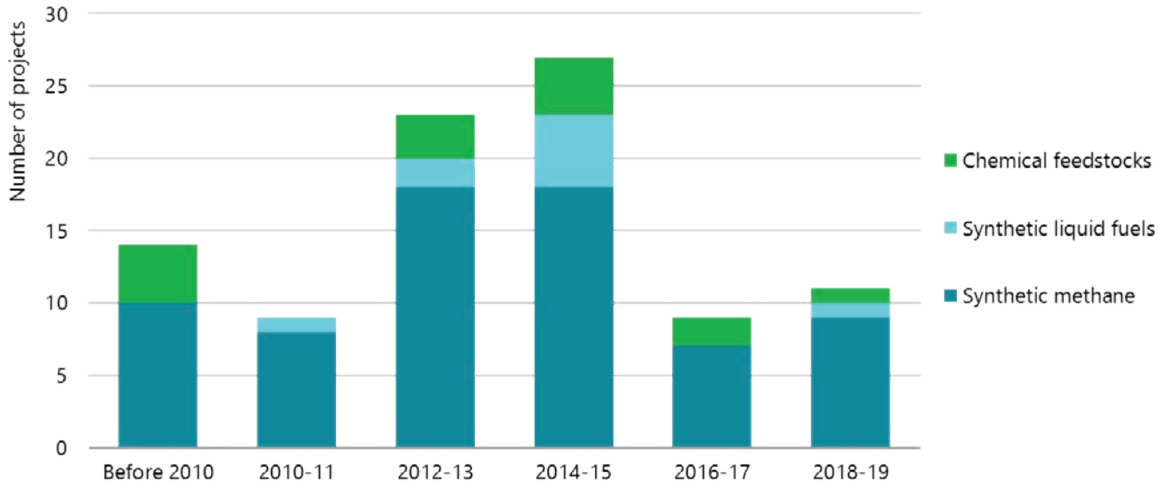
Ammonia has been made with hydrogen from electrolysers running on hydropower and nitrogen from ASUs since the 1920s, with a few plants in Norway feeding the entire European demand for nitrogen fertilisers (IEA, 2017). New projects are, however, now underway to produce ammonia from renewable electricity. For example, a commercial-scale ammonia plant with a production capacity of 50 tonnes ammonia per day and an electrolyser capacity of 30 MW_e is being built in Port Lincoln in South Australia, and will be powered by wind and solar electricity (Ammonia Industry, 2018).

Synthetic hydrocarbons

Hydrogen can be combined with CO_2 to produce synthetic hydrocarbons such as methane, or synthetic liquid fuels such as methanol, diesel, gasoline and jet fuel. Some of these products have higher energy densities than hydrogen or ammonia:

- **Synthetic methane:** This can be directly produced from CO_2 and hydrogen in a methanation process. Applications of the methanation process today rely mostly on catalytic (thermochemical) methanation. Biological methanation is also possible, in which microorganisms in an anaerobic environment convert hydrogen and CO_2 into methane, but this is at an earlier stage of development. The majority of the projects for hydrogen-based fuels and feedstocks have so far been aimed at producing synthetic methane, with almost 70 demonstration plants (Figure 21). Most of these are located in Germany and other European countries.

Figure 21. Number of new projects for making various hydrogen-based fuels and feedstocks from electrolytic hydrogen



Sources: IEA analysis based on Chehade et al. (2019), "Review and analysis of demonstration projects on Power-to-X pathways in the world", IEA (2018), *World Energy Investment*, and the World Energy Council (2018), "Hydrogen an enabler of the Grand Transition" and data provided by IEA Hydrogen Technology Collaboration Programme.

The majority of the pilot and demonstration projects for hydrogen-based fuels and feedstocks produce synthetic methane.

- **Synthetic diesel or kerosene:** The production of synthetic diesel or kerosene requires hydrogen and carbon monoxide as inputs. Since carbon monoxide is generally not easily available, CO_2 can be used instead. This CO_2 is first converted into carbon monoxide, and the resulting synthesis gas of carbon monoxide and hydrogen is then converted (via

Fischer-Tropsch [FT] synthesis)[13] to raw liquid fuels and, with further upgrading, into synthetic diesel or kerosene. FT synthesis is relatively slow and requires costly investment.

- **Synthetic methanol:** Methanol is the simplest alcohol. It has an energy content equal to 19.9 megajoules per kilogram (LHV) and a 80% higher energy density than liquid hydrogen. As a liquid it is easily transportable, like other common petroleum fuels. It is as toxic as common liquid petroleum fuels, but unlike them it is not carcinogenic or mutagenic. Methanol is soluble in water and is biodegradable, and its production from synthesis gas is fully commercial. Around 40% of global methanol production today is used for energy purposes, but methanol can also be used as the building block for synthesising a range of chemicals, e.g. for the production of plastics.

Significant amounts of electricity and generation capacity are required for the production of synthetic hydrocarbons because of the low overall efficiency of production processes. Around 1 000 TWh and 700 TWh of electricity would be needed as input for synthetic hydrocarbons to provide just 1% of current global oil and global gas production respectively, representing around 4% and 3% of global electricity generation in 2018. This would require 600 GW and 400 GW of solar PV capacity at a capacity factor of 20%, or 340 GW and 230 GW of onshore wind capacity at a capacity factor of 35%.

The production of synthetic hydrocarbon from hydrogen uses CO_2 as input, which can be derived through various means (Box 6). In Werlte in Germany, for example, a plant with an electrolyser capacity of 6 MW_e has been producing 300 m^3 per hour of synthetic methane since 2013, with CO_2 being provided by a biogas plant. A synthetic liquids plant for methanol production has been operating in Iceland since 2012 with an electrolyser capacity of 6 MW_e and a methanol output of 4 000 tonnes per year. The required CO_2 is captured from a geothermal power plant.

Box 5. CO_2 sources for synthetic hydrocarbons

The production of methane or liquid hydrocarbon fuels and feedstocks from hydrogen often uses CO_2 as input. For example, replacing today's global fossil kerosene demand of 2 600 million barrels per year completely with synthetic kerosene would require 1 gigatonne of carbon dioxide ($GtCO_2$) per year. If the synthetic hydrocarbon fuel is combusted, this CO_2 is again released to the atmosphere (assuming the combustion process is not equipped with CCUS). From a climate perspective, the source of CO_2 is therefore vitally important.

One option is to acquire CO_2 produced from the combustion of fossil fuels, or from various industry plants offering more concentrated CO_2 streams such as in cement production. Although the CO_2 is based on fossil fuels, its utilisation can contribute to CO_2 reduction as, in principle, each carbon molecule is being used twice: the carbon contained in a fossil fuel is used to produce energy or in an

[13] FT synthesis is a fully commercial process. Several large-scale plants converting coal or natural gas via FT synthesis into liquid fuels are in operation. The largest coal-to-liquid plant has operated since the 1980s in Secunda, South Africa, with a capacity of 160 000 barrels per day (bbl/d). The largest gas-to-liquid plant has operated in Qatar since 2011 at 140 000 bbl/d.

industrial production process; and then the resulting CO_2 is used in combination with hydrogen to produce a synthetic hydrocarbon fuel. However, such a system would still involve emissions of CO_2 from fossil fuels and would have a theoretical upper limit of 50% emissions reduction (Bennett, Schroeder and McCoy, 2014).

For very low CO_2 pathways, non-fossil CO_2 sources would be needed. One option is to use CO_2 formed at high purity during the production of biogas and bioethanol. Capturing CO_2 from these processes requires only moderate additional investment and energy, and has CO_2 capture costs as low as USD 20–30/tCO_2 (Irlam, 2017). If the production of the hydrogen-based fuel is at the same site as the production of the upgraded biogas or biofuel, then the two product streams can be blended to take advantage of the same infrastructure for onward distribution. There is also an efficiency from maximising the use of the carbon contained in the original biomass input. If biomass gasification were to reach commercial scale, it could also become a potential CO_2 source owing to relatively low CO_2 capture costs and compatibility with most biomass feedstocks (Ericsson, 2017). To raise efficiency, it may not be necessary to separate the CO_2 if the externally-sourced hydrogen can be introduced directly into the gasification products (containing CO_2, and also hydrogen and carbon monoxide) so that they can be converted to synthetic fuels in one combined reaction process (Hannula, 2016). However, it remains uncertain whether sufficient biogenic CO_2 could be available in the future at the scale needed for widespread production of hydrogen-based synthetic hydrocarbon fuels.

CO_2 can also be captured directly from the atmosphere, where there a no constraints on the availability of CO_2. However, due to the low atmospheric concentrations of CO_2, DAC is more energy-intensive than CO_2 capture from gases formed at power plants or industrial facilities. Today's units require both electricity and heat for CO_2 capture, with the two main types of system being high-temperature or low-temperature DAC. High-temperature DAC operates at around 900°C and uses an aqueous solution to absorb CO_2, while low-temperature DAC operates at around 100°C with a solid sorbent. Estimates for the energy requirements of DAC are in the order of 250–400 kWh of heat and 1 500–1 750 kWh of electricity per tonne of CO_2. The heat requirement can, however, be reduced by integrating DAC with the production of synthetic hydrocarbon fuels (Fasihi and Breyer, 2017). DAC plants operate today at a scale of 900 tCO_2 per year or less in Canada, Iceland, Italy and Switzerland, but practical experience remains limited. Cost estimates for DAC remain uncertain, but studies estimate that in the long term costs for DAC may fall to a range of USD 94–232/tCO_2 for high-temperature DAC (Keith et al., 2018) and USD 130–170t CO_2 for low-temperature DAC (Fasihi, Efimova and Breyer, 2019).

The environmental impact of hydrogen-based synthetic hydrocarbon fuels depends on the CO_2 intensity of both the hydrogen and the CO_2. Policy must therefore consider the CO_2 intensity of the whole value chain, including the source of the CO_2, to avoid outcomes that do not lead to CO_2 reduction overall. Policies that incentivise hydrogen production and hydrogen-based fuel production separately could inadvertently encourage the separation of CO_2 from hydrogen in fossil methane and its recombination with hydrogen to produce methane again, with an investment of energy in the process. A low-carbon hydrogen-based fuel is one with net emissions after combustion that are zero, or nearly zero, after subtracting emissions of CO_2 originating from a biogenic or atmospheric carbon source. It is important to manage this accounting challenge effectively. The simplest approach, if feasible, may be to certify and track carbon through the supply chain as "fossil" or "non-fossil". The operator of the CO_2 capture facility would be credited with lower emissions for their process compared with the same process without CO_2 capture.

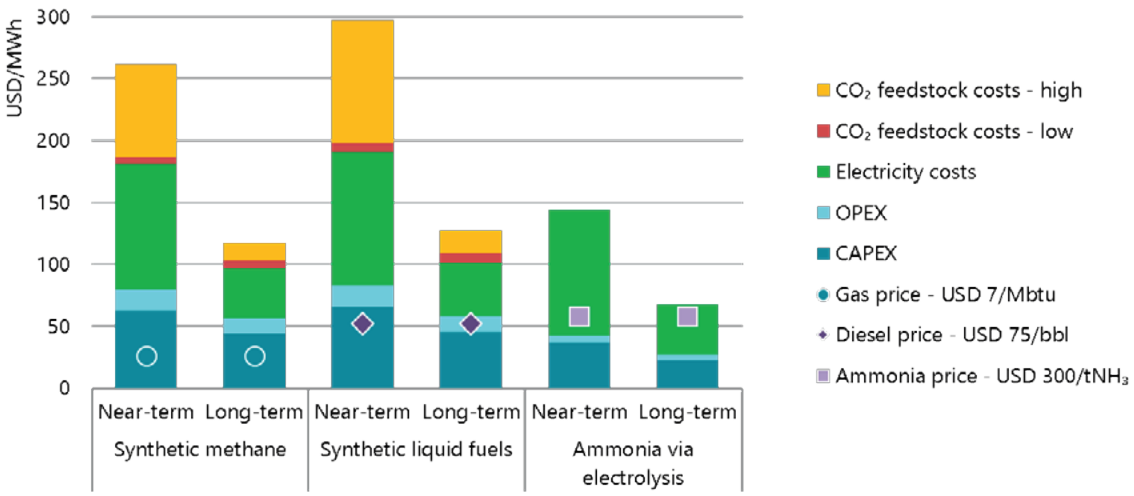
Sources: Bennett, Schroeder and McCoy (2014), "Towards a framework for discussing and assessing CO_2 utilisation in a climate context", Irlam (2017), "Global costs of carbon capture and storage: 2017 update"; Ericsson (2017), "Biogenic carbon dioxide as feedstock for production of chemicals and fuels: A Techno-economic assessment with a European perspective"; Hannula (2016), "Hydrogen enhancement potential of synthetic biofuels manufacture in the European context: A techno-economic assessment"; Keith et al. (2018), "A process for capturing CO_2 from the atmosphere"; Fasihi and Breyer (2017), "Synthetic methanol and dimethyl ether production based on hybrid PV-wind power plants"; Fasihi, Efimova and Breyer (2019), "Techno-economic assessment of CO_2 direct air capture plants".

Production costs

The main cost components for the production of ammonia and synthetic hydrocarbons are the CAPEX and the hydrogen costs, together with the electricity costs if the hydrogen is produced through electrolysis and, for synthetic hydrocarbons, the CO_2 feedstock costs.

Capital costs constitute around 30–40% of the total production costs for ammonia and synthetic hydrocarbons if the hydrogen is produced from electricity. CAPEX costs are dominated by the costs of the electrolyser, while the synthesis process and other equipment components have a smaller impact.[14] Learning effects could roughly halve the CAPEX costs of the different production pathways in the long term, thereby bringing down the cost of production (Figure 22).

Figure 22. Indicative production costs of electricity-based pathways in the near and long term



Notes: NH_3 = ammonia.; renewable electricity price = USD 50/MWh at 3 000 full load hours in near term and USD 25/MWh in long term; CO_2 feedstock costs lower range based on CO_2 from bioethanol production at USD 30/tCO_2 in the near and long term; CO_2 feedstock costs upper range based on DAC = USD 400/tCO_2 in the near term and USD 100/tCO_2 in the long term; discount rate = 8%. More information on the underlying assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019.

Future cost reductions for hydrogen-based products from electricity will depend on lowering the cost of electricity, with cost reductions for CO_2 feedstocks also being critical for synthetic hydrocarbons.

[14] For example, for ammonia production from electrolytic hydrogen, the synthesis process and the air separation unit account for less than 5% of the total CAPEX.

For electricity-based pathways, the largest cost component for hydrogen-based products is typically electricity, accounting for about 40–70% of the production cost of different hydrogen-based products.[15] An electricity price of USD 20/MWh alone is equivalent to USD 60–70/bbl when used for liquid hydrocarbon production and USD 10–12/MBtu of methane.[16] These prices are already close to the price range of fossil fuel options even without adding CAPEX and OPEX, CO_2 feedstock cost and other costs. Reducing the cost of electricity is therefore an important goal, together with increasing the overall efficiency of the conversion chain (Figure 20).

CO_2 feedstock costs are an important further cost component in the case of synthetic hydrocarbon fuels. They can vary significantly, depending on the availability of suitable CO_2 sources. Costs may be low if pure CO_2 is readily available as a by-product of a production process such as the manufacture of bioethanol, but can be much higher. CO_2 feedstock costs of USD 30/tCO_2 translate for synthetic diesel into a cost of USD 13/bbl; and CO_2 feedstock costs of USD 100/tCO_2 into a cost of USD 42/bbl. However, whether a producer of CO_2 would be willing to sell it to a synthetic fuel manufacturer at close to the cost of capture would depend on the prevailing CO_2 emissions price or the level of any competing financial benefit for sending the CO_2 to long-term geological storage, if available.

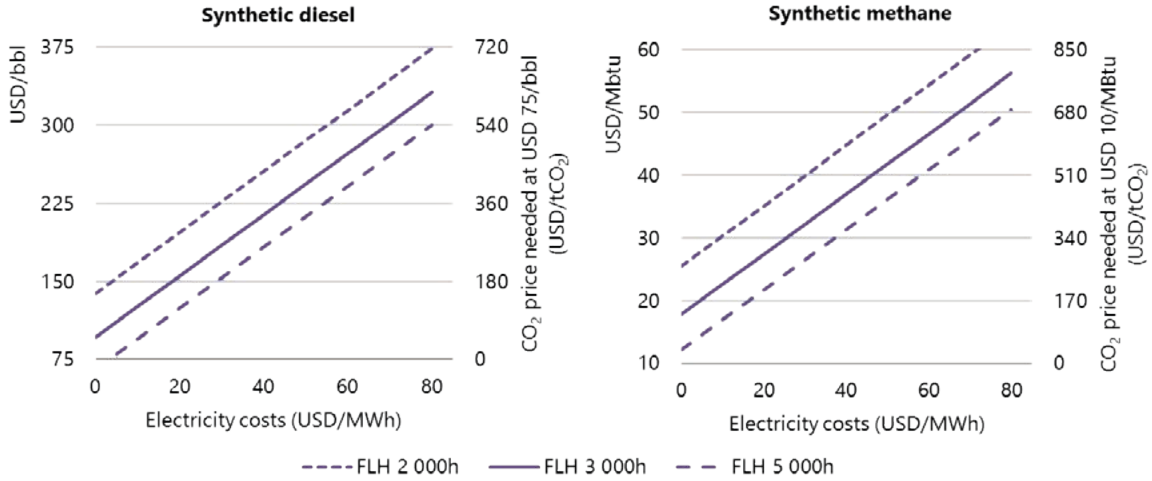
When the production costs of different electricity-based pathways are compared, the costs for ammonia come out as lower than those for synthetic hydrocarbons (Figure 22). Synthetic hydrocarbons benefit, however, from the existing fossil fuel-based infrastructure for transmission and distribution, which means that it is cheaper to transport them to end users. They also have a greater number of established end uses. The use of ammonia is so far limited to its application as a feedstock in the chemical industry, and value chains for using ammonia as a fuel in the energy sector are virtually non-existent today.

High CO_2 prices (or equivalent policies discouraging fossil fuel use) would be needed for synthetic hydrocarbon fuels to become competitive with fossil fuel alternatives. If, for example, synthetic diesel can be produced at a cost of USD 150/bbl, a CO_2 price of USD 180/tCO_2, or equivalent policy measure, would be needed for synthetic diesel to become competitive with fossil diesel at USD 75/bbl (Figure 23). The high level of equivalent CO_2 prices that would be needed for synthetic hydrocarbon fuels from electricity to compete with fossil fuels suggests that the use of synthetic hydrocarbon fuels at a larger scale is unlikely to happen in the near term. The economics of hydrogen-based fuels and feedstocks does, however, depend on the specific local conditions and the configuration of the different process components, as illustrated in Box 6 for the case of ammonia production at different locations in China.

[15] In case of low CO_2 feedstock costs in Figure 22.

[16] Ranges reflect different electrolyser efficiencies.

Figure 23. Synthetic diesel and methane production costs and CO_2 price penalty needed for competitiveness with fossil diesel and natural gas in the long term



Notes: FLH: full load hours. Left axes show the production cost for synthetic diesel and methane, while the right axes show the CO_2 price needed to reach competitiveness with fossil diesel at USD 75/bbl and with natural gas at USD 10/MBtu. More information on the underlying assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

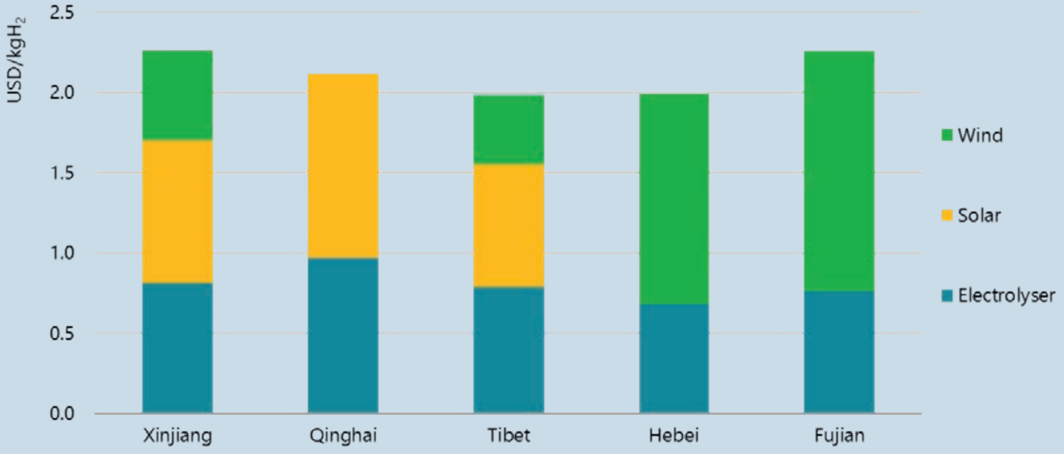
A combination of low electricity costs and high CO_2 prices is needed to make synthetic diesel and methane competitive with fossil crude oil and natural gas.

Box 6. Production of hydrogen and ammonia from solar and wind in China

Developing cost-effective hydrogen supply chains requires location-specific aspects of the different technology options to be taken into account. This applies to the production of both hydrogen and hydrogen-based products. China provides an example: it has abundant renewable energy resources that are often located in vast sparsely populated regions far away from large industrial clusters. In some places, renewable energy has been deployed so rapidly that electricity networks have had difficulty adapting in real time. This has provided an opportunity for producers of hydrogen and hydrogen-rich chemicals to tap into renewable resources. Ammonia production is one opportunity given that China is the world's largest user of nitrogen fertilisers, consuming 46 Mt per year.

A detailed economic assessment by the IEA, based on hourly solar and wind data over a year in five locations across different provinces, suggests hydrogen can be produced at a cost of USD 2–2.3/kgH_2. In some provinces the lowest production costs are reached by using only solar (Qinghai) or wind (Hebei and Fujian), while in Xinjiang and Tibet performance is best with a combination of the two.

Estimated hydrogen production costs from solar and wind in China, 2020



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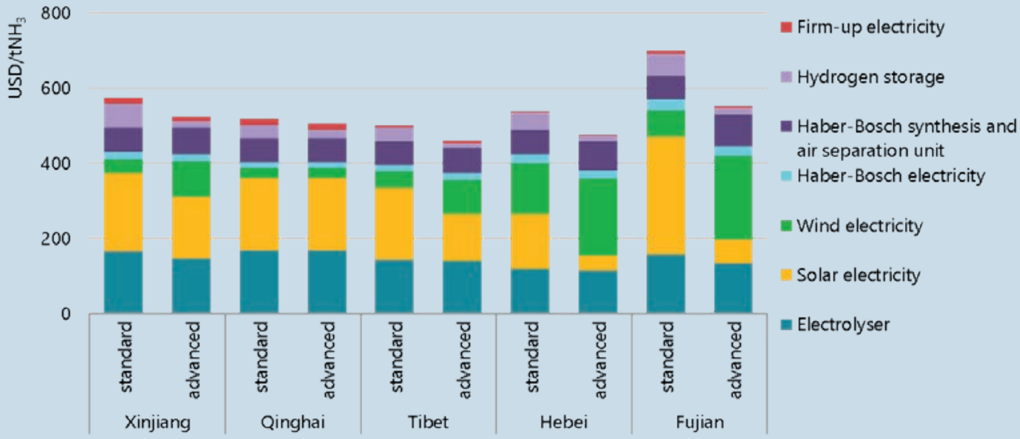
The search for the optimal format for ammonia production based on variable renewables is more complex. Calculating the appropriate size of solar and wind capacity involves taking account of the size of the electrolysers, the hydrogen buffer storage and of the Haber-Bosch loop, as well as the use of more costly "firm-up" electricity to run the Haber-Bosch loop continuously.

In all provinces a mix of solar and wind is needed for best performance, despite cost differences between both resources. Mixing reduces the size of the hydrogen buffer storage and reduces the need for more costly firm-up electricity; it only marginally increases the capacity factor of the Haber-Bosch loop and the electrolysers

Estimated ammonia production costs from solar and wind in China, 2020



Notes: tNH_3 = tonne of ammonia. Left-hand bars correspond to "standard" flexibility of the Haber-Bosch operations with a 40% downward flexibility of the Haber-Bosch synthesis; right-hand bars correspond to the "advanced" flexibility case, allowing 80% downward flexibility and the possibility of shutting down the synthesis process completely. From bottom to top, the bars show the following costs: electrolyser, electricity from solar and wind for hydrogen production, renewable electricity for running the Haber-Bosch synthesis, Haber-Bosch synthesis and air separation unit for nitrogen production, hydrogen buffer storage and firm-up electricity to run the Haber-Bosch process when there is not enough wind at night.

Source: IEA 2019. All rights reserved.

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Chapter 3: Storage, transmission and distribution of hydrogen

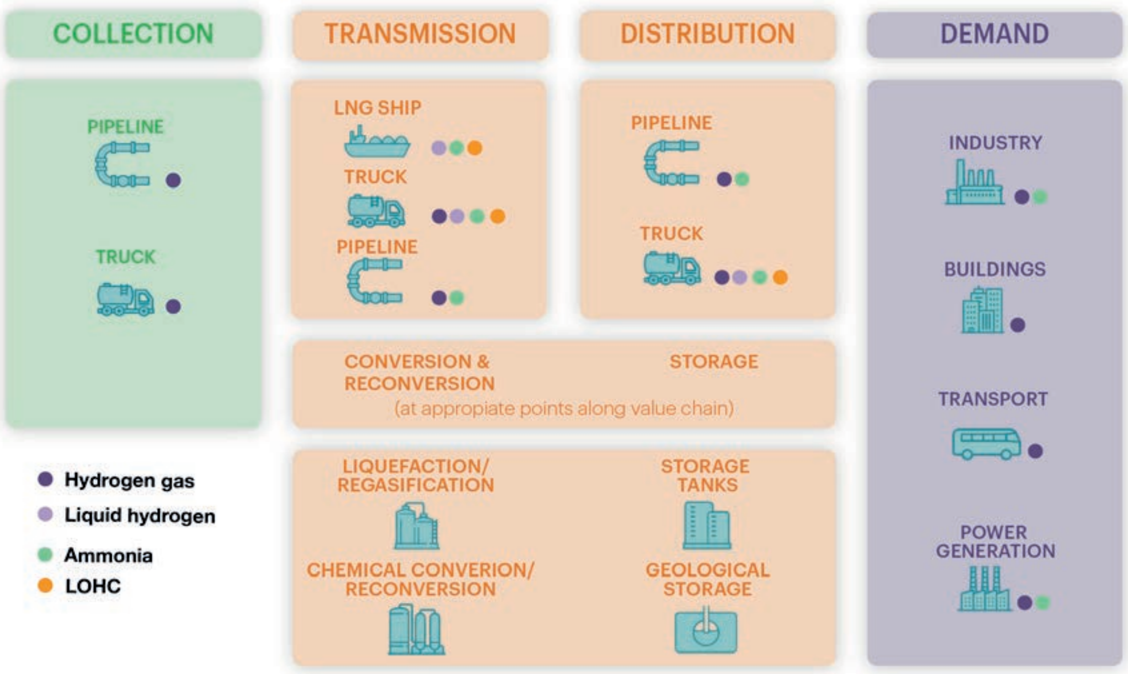
- **Transport and storage costs will play a significant role in the competitiveness of hydrogen.** If hydrogen can be used close to where it is made, these costs could be close to zero. However, if the hydrogen has to travel a long way before it can be used, the costs of transmission and distribution could be three times as large as the cost of hydrogen production.
- **The smooth operation of large-scale and intercontinental hydrogen value chains will depend on the availability of adequate storage capacity and functionality.** Various storage options are available today, with underground facilities that can hold tens of thousands of tonnes of hydrogen already in operation. Further research is needed to assess what storage is likely to be needed in the future in terms of volume, duration, price, and speed of discharge, and to examine options to promote their development.
- **Long-distance transmission and local distribution of hydrogen is difficult given its low energy density.** Compression, liquefaction or incorporation of the hydrogen into larger molecules are possible options to overcome this hurdle. Each option has advantages and disadvantages, and the cheapest choice will vary according to geography, distance, scale and the required end use.
- **Blending hydrogen into existing natural gas pipeline networks would provide a boost to hydrogen supply technologies** without incurring the investment costs and risks of developing new hydrogen transmission and distribution infrastructure. Action to update and harmonise national regulations that set limits on allowed concentrations of hydrogen in natural gas streams would help to facilitate such blending.
- **If hydrogen needs to be shipped overseas, it generally has to be liquefied or transported as ammonia or in liquid organic hydrogen carriers (LOHCs).** For distances below 1 500 km, transporting hydrogen as a gas by pipeline is likely to be the cheapest delivery option; above 1 500 km, shipping hydrogen as ammonia or an LOHC is likely to be more cost-effective. These alternatives are cheaper to ship, but the costs of conversion before export and reconversion back to hydrogen before consumption are significant. They may also sometimes give rise to safety and public acceptance issues.
- **Pipelines are likely to be the most cost-effective long-term choice for local hydrogen distribution if there is sufficiently large, sustained and localised demand.** However, distribution today usually relies on trucks carrying hydrogen either as a gas or liquid, and this is likely to remain the main distribution mechanism over the next decade.
- **There are a number of regions where hydrogen imports could be cheaper than domestic production.** In Japan domestic production of hydrogen using electrolysers and its distribution could cost around USD 6.5 per kgH_2 in 2030; hydrogen imported from Australia could cost around USD 5.5/kgH_2. Similar opportunities may develop in Korea and parts of Europe. Using ammonia directly in end-use sectors could further improve the competitiveness of imports. Even where importing hydrogen is not the cheapest option, some energy-importing countries may wish to consider imports to increase their energy diversity and access to low-carbon energy.

If hydrogen is to play a meaningful role in clean, flexible energy systems, it will be largely because it can be used to store energy in large quantities for long periods and to move it over very long distances. Delivery infrastructure choices and costs are thus critically important.

Today hydrogen is usually stored and delivered in compressed gas or liquid form. The majority is either produced and consumed on-site (around 85%) or transported via trucks or pipelines (around 15%). In the future the balance between these options could change and new alternatives could emerge. The competitiveness of the different options will depend on the distance over which hydrogen is transported, and on scale and end use. Long-distance transport would enable the export of hydrogen from low-cost production regions to high-cost ones (Figure 24). For energy import-dependent countries, it could also improve the diversity of energy sources and increase energy security.

This chapter first looks at possible storage options for hydrogen and hydrogen carriers. It then examines the possibility of using existing natural gas grids to transport and distribute hydrogen. This is followed by a discussion of the various delivery options and costs for long-distance transmission and local distribution. It finishes with an assessment of the total cost of storage, transmission and distribution for a number of different trade routes. Our assessment of costs is based on the most recent data from industry and scientific literature; however, there is inevitably a high degree of uncertainty about many of these estimates including those relating to future technology developments.

Figure 24. Transmission, distribution and storage elements of hydrogen value chains



Note: LOHC = liquid organic hydrogen carrier.
Source: IEA 2019. All rights reserved.

Depending on the context and type of hydrogen carrier, various components can be combined in value chains for hydrogen transmission and distribution, leading to location-specific costs.

Hydrogen storage

Today hydrogen is most commonly stored as a gas or liquid in tanks for small-scale mobile and stationary applications. However, the smooth operation of large-scale and intercontinental hydrogen value chains in the future will require a much broader variety of storage options. At an export terminal, for example, hydrogen storage may be required for a short period prior to shipping. Hours of hydrogen storage are needed at vehicle refuelling stations, while days to weeks of storage would help users protect against potential mismatches in hydrogen supply and demand. Much longer-term and larger storage options would be required if hydrogen were used to bridge major seasonal changes in electricity supply or heat demand, or to provide system resilience.[17] The most appropriate storage medium depends on the volume to be stored, the duration of storage, the required speed of discharge, and the geographic availability of different options. In general, however, geological storage is the best option for large-scale and long-term storage, while tanks are more suitable for short-term and small-scale storage.

Geological storage

Salt caverns, depleted natural gas or oil reservoirs and aquifers are all possible options for large-scale and long-term hydrogen storage (HyUnder, 2014; Kruck et al., 2013). They are currently used for natural gas storage and provide significant economies of scale, high efficiency (the quantity of hydrogen injected divided by the quantity that can be extracted), low operational costs and low land costs. These characteristics mean that they are likely to be the lowest-cost option for hydrogen storage even though hydrogen has low energy density compared to natural gas (Bünger et al., 2014).

Salt caverns have been used for hydrogen storage by the chemical sector in the United Kingdom since the 1970s and the United States since the 1980s. They typically cost less than USD 0.6/kgH_2, have an efficiency of around 98%, and have a low risk of contaminating the hydrogen that is stored (H21, 2018; Bünger et al., 2014; Lord, Kobos and Borns, 2014). Their high pressures enable high discharge rates, making them attractive for industrial and power sector applications. Because salt cavern storage is generally operated as a series of separate, adjacent caverns, natural gas storage facilities could be converted to hydrogen stores one at a time as hydrogen use increases, reducing upfront costs. The United States has the largest salt cavern hydrogen storage system currently in operation; it can store around 30 days of hydrogen output from a nearby steam methane reformer (between 10 and 20 thousand tonnes of H_2 (ktH_2)) to help manage the supply and demand for refining and chemicals. The United Kingdom has three salt caverns that can store 1 ktH_2, while a 3.5 ktH_2 storage demonstration project in a salt cavern is under preparation in Germany (planned for 2023).

Depleted oil and gas reservoirs are typically larger than salt caverns, but they are also more permeable and contain contaminants that would have to be removed before the hydrogen could be used in fuel cells. Water aquifers are the least mature of the three geological storage options, and there is mixed evidence for their suitability (although they were previously used for years to store town gas with 50–60% hydrogen). As with oil and gas reservoirs, natural barriers trap the vast majority of the hydrogen deep underground. However, reactions with micro-organisms, fluids and rocks can lead to losses of hydrogen. As they have not previously been

[17] An additional option would be for hydrogen to provide short-duration electricity storage, for example for less than a day. However, it is likely that pumped-storage hydropower, compressed air storage and/or batteries will outcompete hydrogen where they are available.

investigated for commercial use with pure hydrogen, many aquifers would also incur exploration and development costs. The feasibility and cost of storing hydrogen in depleted reservoirs and aquifers have still to be proven. If they could overcome the challenges and establish themselves as viable, both would be options to provide storage on the scale required for seasonal hydrogen storage, especially in locations without access to salt caverns.

Although geological storage offers the best prospects for long-term and large-scale storage, the geographical distribution, large size and minimum pressure requirements of sites make them much less suitable for short-term and smaller-scale storage. For these applications, tanks are the most promising option.

Storage tanks

Tanks storing compressed or liquefied hydrogen have high discharge rates and efficiencies of around 99%, making them appropriate for smaller-scale applications where a local stock of fuel or feedstock needs to be readily available.

Compressed hydrogen (at 700 bar pressure) has only 15% of the energy density of gasoline, so storing the equivalent amount of energy at a vehicle refuelling station would require nearly seven times the space. Ammonia has a greater energy density and so would reduce the need for such large tanks, but these advantages have to be weighed against the energy losses and equipment for conversion and reconversion when end uses require pure hydrogen (see below). When it comes to vehicles rather than filling stations, compressed hydrogen tanks have a higher energy density than lithium-ion batteries, and so enable a greater range in cars or trucks than is possible with battery electric vehicles.

Research is continuing with the aim of finding ways to reduce the size of the tanks, which would be especially useful in densely populated areas. This includes looking at the scope for underground tanks that can tolerate 800 bar pressure and so enable greater compression of hydrogen. Hydrogen storage in solid-state materials such as metal and chemical hydrides is at an early stage of development, but could potentially enable even greater densities of hydrogen to be stored at atmospheric pressure.

Hydrogen transmission and distribution

The low energy density of hydrogen means that it can be very expensive to transport over long distances. Nonetheless, a number of possible options are available to overcome this hurdle, including compression, liquefaction or incorporation of the hydrogen into larger molecules that can be more readily transported as liquids. In many countries there is an extensive existing natural gas pipeline network that could be used to transport and distribute hydrogen. New infrastructure could also be developed, with dedicated pipeline and shipping networks potentially allowing large-scale overseas hydrogen transport. Each possible option has a variety of advantages and disadvantages, and the cheapest choice will vary according to geography, distance, scale and the required end use of the hydrogen. This section discusses the opportunities and issues related to each of the main transmission and distribution options.

Blending hydrogen in existing natural gas grids

Developing a new hydrogen value chain would be contingent upon successfully completing and connecting production, transmission, distribution, storage and end-use infrastructure. This would require co-ordinated investment by many different market participants, which could be challenging for them to implement. Blending hydrogen into the natural gas infrastructure that already exists would, however, avoid the significant capital costs involved in developing new transmission and distribution infrastructure. Further, if blending were to be carried out at low levels, while it might increase the cost of natural gas delivery to consumers, it would also provide reductions in CO_2 emissions. Blending would be considerably easier to implement if steps were taken to clarify existing national regulations on hydrogen in natural gas and to harmonise regulations across borders.

There are almost 3 million kilometres (km) of natural gas transmission pipelines around the world and almost 400 billion cubic metres (bcm) of underground storage capacity; there is also an established infrastructure for international liquefied natural gas (LNG) shipping (Snam, IGU and BCG, 2018; Speirs et al., 2017). If some of this infrastructure could be used to transport and use hydrogen, it could provide a major boost to the development of hydrogen. For example, a blend of 3% hydrogen[18] in natural gas demand globally (around 3 900 bcm in 2018) would require close to 12 MtH_2. If the majority of this hydrogen came from electrolysers, then this by itself would require around 100 gigawatts (GW) of installed electrolyser capacity (at a 50% load factor), a level that could deliver around a 50% reduction in the capital cost of electrolysers. However, hydrogen blending faces a number of challenges:

- The energy density of hydrogen is around a third of that of natural gas and so a blend reduces the energy content of the delivered gas: a 3% hydrogen blend in a natural gas transmission pipeline would reduce the energy that the pipeline transports by around 2% (Haeseldonckx and D'haeseleer, 2007). End users would need to use greater gas volumes to meet a given energy need. Similarly, industrial sectors that rely on the carbon contained in natural gas (e.g. for treating metal) would have to use greater volumes of gas.
- Hydrogen burns much faster than methane. This increases the risk of flames spreading. A hydrogen flame is also not very bright when burning. New flame detectors would probably be needed for high-blending ratios.
- Variability in the volume of hydrogen blended into the natural gas stream would have an adverse impact on the operation of equipment designed to accommodate only a narrow range of gas mixtures (Abbott, Bowers and James, 2013). It could also affect the product quality of some industrial processes.
- The upper limit for hydrogen blending in the grid depends on the equipment connected to it, and this would need to be evaluated on a case-by-case basis. The component with the lowest tolerance will define the tolerance of the overall network.

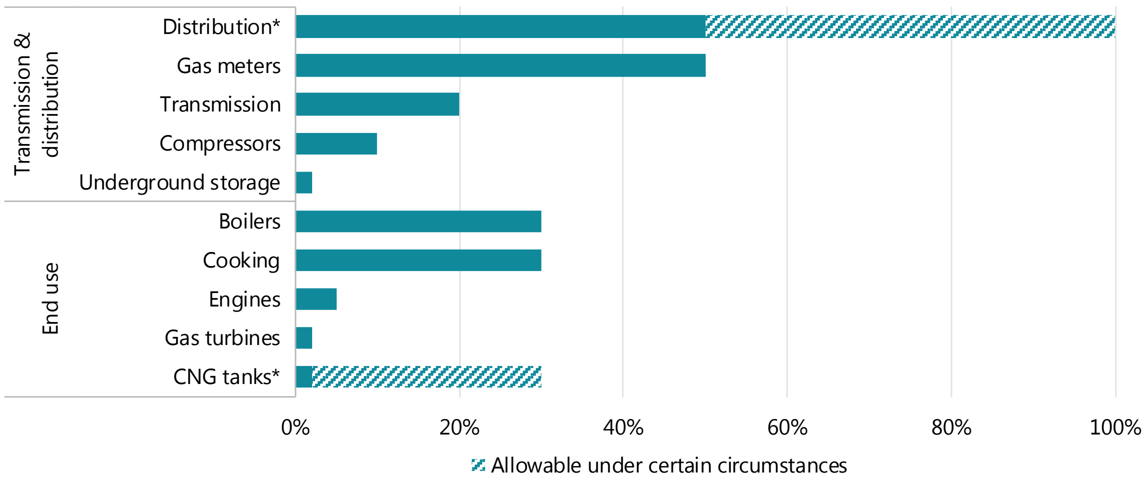
Some existing components along the natural gas value chain have a high tolerance for hydrogen blending (Figure 25). For example, polyethylene distribution pipelines can handle up to 100% hydrogen, and the H21 Leeds City Gate project in the United Kingdom aims to demonstrate the feasibility of delivering hydrogen through the gas distribution network to provide heat for households and businesses. Similarly, salt caverns can store pure hydrogen instead of natural gas without any need for upgrades. Many gas heating and cooking appliances in Europe are certified for up to 23% hydrogen, although the effects of such levels over many years of use are still unclear (Altfeld and Pinchbeck, 2013).

However, there are other parts of the existing natural gas value chain that cannot tolerate high levels of blended hydrogen. The biggest constraint is likely to be in the industrial sector, where many industrial applications have not been certified or assessed in detail for hydrogen blending.

[18] All blending percentages in this section are on a volume basis.

For example, chemical producers using natural gas as a feedstock may need to adjust processes and contracts with natural gas suppliers that stipulate a narrow specification of gas content. The control systems and seals of existing gas turbines are not designed for the properties of hydrogen and can tolerate less than 5% blended hydrogen (ECS, 2015). A similar issue arises for many installed gas engines, where the recommended maximum level of blended hydrogen is 2%. Minor modifications to existing turbines and engines might enable them to handle higher hydrogen blending levels, and new equipment could be specifically designed to cope with higher levels of hydrogen. But such adjustments would take time and money.

Figure 25. Tolerance of selected existing elements of the natural gas network to hydrogen blend shares by volume



* The higher tolerance of CNG tanks is for Type IV tanks (although the tolerance for CNG tanks may be as low as 0.1% depending on the humidity of the natural gas (United Nations, 2014); the higher tolerance for distribution would require specific safety assessments.

Note: CNG = compressed natural gas.

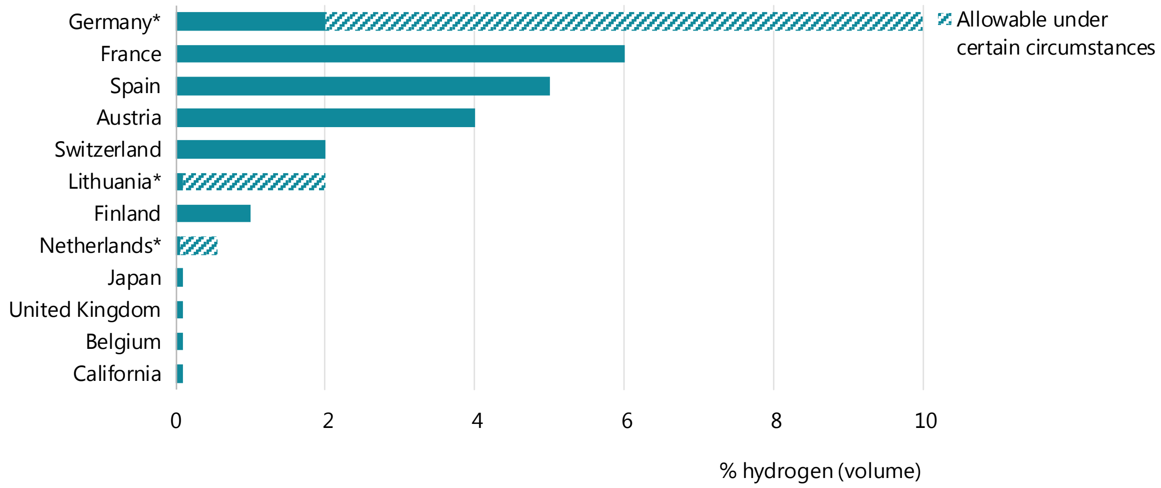
Sources: Altfeld and Pinchbeck (2013), "Admissible hydrogen concentrations in natural gas systems", Gas Energy http://www.gas-for-energy.com/products/2013-admissible-hydrogen-concentrations-in-natural-gas-systems-1/; Jones, Kobos and Borns (2018), "Geologic storage of hydrogen: Scaling up to meet city transportation demands", *Inter. Journal of Hydrogen Energy*; Kouchachvili and Entchev (2018), "Power to gas and H_2/NG blend in SMART energy networks concept", *Renewable Energy*; Melaina, Antonia and Penev (2013), "Blending hydrogen into natural gas pipeline networks: A review of key issues", National Renewable Energy Laboratory; Müller-Syring and Henel (2014), "Wasserstofftoleranz der Erdgasinfrastruktur inklusive aller assoziierten Anlagen", DVGW; Reitenbach, et al. (2015), "Influence of added hydrogen on underground gas storage: a review of key issues", *Environmental Earth Science*; Weidner et al. (2016), "Sector Forum Energy Management/Working Group Hydrogen Final Report".

CNG tanks, turbines and engines have the lowest hydrogen tolerance. Minor adaptations could increase the grid's tolerance and exploit its transport capacity.

Existing national regulations for gas quality are defined by the elements along the gas value chain that are least able to cope with blending. Many regions specify a maximum of 2% blending, with a few specifying between 4% and 6% (Figure 26). Germany specifies a maximum of 10%, but less than 2% if CNG filling stations are connected to the network. Specifications for certain pieces of equipment can also be restrictive: for example, European standards stipulate that the hydrogen content of natural gas streams must be below 1% for control systems and seals of gas turbines.

Since natural gas is internationally traded, harmonising blend limits across borders is a crucial step to support deployment. Standards should also account for possible variability in hydrogen blending levels over time. In Europe a number of technical committees and industry working groups (e.g. HyReady and HIPS-Net) are examining standards for hydrogen blending, while the European Commission is also examining standards and the role of renewable gases and hydrogen in the natural gas network (Eurogas, 2018).

Figure 26. Current limits on hydrogen blending in natural gas networks



* Higher limit for Germany applies if there are no CNG filling stations connected to the network; higher limit for the Netherlands applies to high-calorific gas; higher limit for Lithuania applies when pipeline pressure is greater than 16 bar pressure.

Sources: Dolci et al. (2019), "Incentives and legal barriers for Power-to-Hydrogen pathways: An international snapshot", *International Journal of Hydrogen*; HyLaw (n.d.), *Online Database*; Staffell et al. (2019) "The role of hydrogen and fuel cells in the global energy system", *Energy and Environmental Science*.

Today most countries limit hydrogen concentrations in the natural gas network; modifying these regulations will be necessary to stimulate meaningful levels of hydrogen blending.

Keeping track of how much hydrogen has been injected into the grid and its carbon intensity is also important. Such an accounting method – sometimes called a "guarantee of origin" – is essential if operators are to be paid a premium for supplying lower-carbon gas. An example is the system in California whereby some customers can purchase certificates for renewable methane blended into the grid despite the gas molecules themselves being untraceable after injection. In Europe the CertifHy project has designed an operational framework for guarantees of origin and issued more than 75 000 digital certificates.

In addition to issues relating to the grid itself, policies to bring about higher blending levels need to incorporate strategies for replacing equipment in homes, offices and factories. The conversion could be done progressively region by region. Implementing policies of this kind would be time-consuming and costly, but not unprecedented: the United Kingdom, Austria, Germany and the United States switched from town gas (with 50% hydrogen) to natural gas in the 1960s and 1970s. The United Kingdom replaced 40 million appliances at a cost of USD 12 billion over 10 years (Dodds and Ekins, 2013).

There are currently 37 demonstration projects examining hydrogen blending in the gas grid. The Ameland project in the Netherlands did not find that blending hydrogen up to 30% posed any difficulties for household devices, including boilers, gas hobs and cooking appliances (Kippers, De Laat and Hermkens, 2011). Injection has also been tested at both the transmission and distribution level. Other European projects are testing the technical and monitoring requirements of underground storage (Hypos, 2017).

Hydrogen blending into the natural gas stream could be used to provide a pure stream of hydrogen if it is separated at the end-use site. There are a number of options to do this, but the cost of these technologies and the need to recompress natural gas once the hydrogen is extracted currently makes this a relatively expensive process. One option, pressure swing adsorption, can cost between USD 3/kgH_2 and USD 6/kgH_2 depending on the blending level and end-use demand (Melaina, Antonia and Penev, 2013).

Overall, hydrogen blending would be likely to increase costs slightly by around USD 0.3/kgH_2 to USD 0.4/kgH_2, on top of the costs of hydrogen production. This increase arises from the need for injection stations on the transmission and distribution grids, as well as higher operational costs (Roland Berger, 2017).

New hydrogen transmission and distribution infrastructure

A number of new options could be developed to transport hydrogen from its point of production to end users. Like natural gas, pure hydrogen can be liquefied before it is transported to increase its density. However, liquefaction requires hydrogen to be cooled to minus 253°C; if the hydrogen itself were to be used to provide this energy, then it would consume between around 25% and 35% of the initial quantity of hydrogen (based on today's technologies) (Ohlig and Decker, 2014). This is considerably more energy than is required to liquefy natural gas, which consumes around 10% of the initial quantity of natural gas.

An alternative possibility is to incorporate the hydrogen into larger molecules that can be more readily transported as liquids. Options include ammonia and LOHCs (Box 7).[19] Ammonia and LOHCs are much easier to transport than hydrogen, but they often cannot be used as final products and a further step is needed to liberate the hydrogen before final consumption (except in cases where ammonia, for example, can be used directly by the final customer). This entails extra energy and cost, which must be balanced against the lower transport costs.

Our analysis indicates that transmission of hydrogen as a gas by pipeline is generally the cheapest option if the hydrogen needs be transported for distances of less than about 1 500 km. For longer distances, transmission as ammonia or LOHC may well be a more cost-effective option, especially if the hydrogen needs to be moved overseas, even taking into account the costs of converting hydrogen into ammonia or LOHC and back again. For local distribution, pipelines are cost-effective for distributing high volumes of hydrogen over longer distances; in other cases trucks are likely to be the cheaper option.

[19] Hydrogen can also be incorporated into other well-established end-use fuels, such as synthetic methane or biofuels (as discussed in Chapter 2), and then shipped in the existing infrastructure for these products and distributed to their existing demand centres, reducing their CO_2 intensity. Whether or not this can be cost-effective depends on the trade-off between the higher costs of the additional processing step and the lower costs of using existing infrastructure. See Chapter 4 for further discussion.

Box 7. Advantages and disadvantages of ammonia and LOHCs

Converting hydrogen to ammonia requires energy equivalent to between 7% and 18% of the energy contained in the hydrogen, depending on the size and location of the system (Aakko-Saksaa et al., 2018; Hansen, 2017; Bartels, 2008). A similar level of energy is lost if the ammonia needs to be reconverted back to high-purity hydrogen at its destination (Brown, 2017; Giddey, 2017). Nevertheless, ammonia liquefies at -33°C, a much higher temperature than is the case for hydrogen, and contains 1.7 times more hydrogen per cubic metre than liquefied hydrogen, which means it is much cheaper to transport than hydrogen. While ammonia already has a well-established international transmission and distribution network (see Chapter 2), it is a toxic chemical and this may limit its use in some end-use sectors. There is also a risk that some uncombusted ammonia could escape, which can lead to the formation of particulate matter (an air pollutant) and acidification (Table below).

Making an LOHC involves "loading" a "carrier" molecule with hydrogen, transporting it, and then extracting pure hydrogen again at its destination. LOHCs have similar properties to crude oil and oil products, and their key advantage is that they can be transported as liquids without the need for cooling. However, as with ammonia, there are costs associated with the conversion and reconversion processes involved. These processes would require energy equivalent to between 35% and 40% of the hydrogen itself (Wulf and Zapp, 2018; Reuß et al., 2017). In addition, the carrier molecules in an LOHC are often expensive and are not used up when hydrogen is created again at the end of the process, so need to be shipped back to their place of origin.

Several different LOHC molecules are under consideration, each with various benefits and drawbacks. In this chapter LOHCs refers to methylcyclohexane (MCH), a relatively low-cost option with toluene as the carrier molecule. Around 22 Mt of toluene is currently produced annually (for commercial products), a quantity that could carry 1.4 MtH_2 if it were to be used as an LOHC. It costs around USD 400–900 per tonne. However, toluene is toxic and would require careful handling. A non-toxic alternative LOHC is dibenzyltoluene. Although this is much more expensive than toluene today, scaling up could make it a more attractive option in the long run, especially given its non-toxic nature. Methanol and formic acid are other options, but they lead to greenhouse gas emissions if used directly (unless produced with non-fossil sources of carbon).

For both ammonia and LOHCs, effective utilisation of the heat released in the conversion process could increase the efficiency of the value chain and reduce overall costs.

Selected properties of hydrogen carriers

		Liquid hydrogen	Ammonia	LOHC (MCH)
Process and technology maturity*	Conversion	Small scale: High Large scale: Low	High	Medium
	Tank storage	High	High	High
	Transport	Ship: Low Pipeline: High Truck: High	Ship: High Pipeline: High Truck: High	Ship: High Pipeline: High Truck: High
	Reconversion	High	Medium	Medium
	Supply chain integration	Medium/high	High	Medium

	Liquid hydrogen	Ammonia	LOHC (MCH)
Hazards**	Flammable; no smell or flame visibility	Flammable; acute toxicity; precursor to air pollution; corrosive	Toluene: flammable; moderate toxicity. Other LOHCs can be safer.
Conversion and reconversion energy required***	Current: 25–35% Potential: 18%	Conversion: 7–18% Reconversion: < 20%	Current: 35–40% Potential: 25%
Technology improvements and scale-up needs	Production plant efficiency; boil-off management	Integration with flexible electrolysers; improved conversion efficiency; H_2 purification	Utilisation of conversion heat; reconversion efficiency
Selected organisations developing supply chain	HySTRA; CSIRO; Fortescue Metals Group; Air Liquide	Green Ammonia consortium; IHI Corporation; US Department of Energy	AHEAD; Chiyoda; Hydrogenious; Framatome; Clariant

* High = proven and commercial; Medium = prototype demonstrated; Low = validated or under development; Small scale = < 5 tonnes per day; Large scale = > 100 tonnes per day.

** Toxicity criteria based on inhalation.

*** Given as a percentage of lower heating value of hydrogen; values are for hydrogen that could be used in fuel cells; lower-purity hydrogen would require less energy.

Sources: Aakko-Saksaa et al. (2018), "Liquid organic hydrogen carriers for transportation and storing of renewable energy – Review and discussion", *Journal of Power Sources*; Bartels, (2008), "A feasibility study of implementing an Ammonia Economy", Iowa State University; Brown, (2017), "Round-trip efficiency of ammonia as a renewable energy transportation media", *Ammonia Energy*; Giddey (2017), "Ammonia as a renewable energy transportation media", *ACS Sust. Chem. Eng.*; Hansen (2017), "Solid oxide cell enabled ammonia synthesis and ammonia based power production"; Reuß et al. (2017), "Seasonal storage and alternative carriers: A flexible hydrogen supply chain model", *Applied Energy*; Wulf and Zapp, (2018), "Assessment of system variations for hydrogen transport by liquid organic hydrogen carriers", *International Journal of Hydrogen Energy*.

Long-distance transmission

Transporting energy over long distances is easier when the energy is a chemical fuel rather than electricity. Chemical fuels tend to have high energy densities, do not suffer losses while being transported, benefit from economies of scale, and allow point-to-point trading or transmission across widespread networks. Most natural gas and oil are moved around the world in large-scale pipelines and ships, and both these options can also be used for hydrogen and hydrogen carriers. Moving hydrogen using trains could also be an inland option for some regions, although this would in general be a more expensive option than moving the hydrogen by pipeline.

Pipelines

There are close to 5 000 km of hydrogen pipelines around the world today, compared with around 3 million km of natural gas transmission pipelines. These existing hydrogen pipelines are operated by industrial hydrogen producers and are mainly used to deliver hydrogen to chemical and refinery facilities. The United States has 2 600 km, Belgium 600 km and Germany just under 400 km (Shell, 2017).

Pipelines have low operational costs and lifetimes of between 40 and 80 years. Their two main drawbacks are the high capital costs entailed and the need to acquire rights of way. These mean that certainty of future hydrogen demand and government support are essential if new pipelines are to be built. Existing high-pressure natural gas transmission pipes could be converted to deliver pure hydrogen in the future if they are no longer used for natural gas, but their suitability must be assessed on a case-by-case basis and will depend on the type of steel used in the pipeline and the purity of hydrogen being transported (NREL, 2013).[20] Recent studies in the Netherlands have suggested that the existing natural gas network could be used to transmit hydrogen with small modifications (Netbeheer Nederland, 2018; DNV GL, 2017). The main challenge is that three times more volume is needed to supply the same amount of energy as natural gas. Additional transmission and storage capacity across the network might therefore be required, depending on the extent of the growth of hydrogen.

Ammonia is often transported by pipeline, and new pipelines for ammonia would be cheaper than new pipelines for pure hydrogen. Ammonia pipelines in the United States currently feed hundreds of retail points and total 4 830 km in length. In Eastern Europe the 2 400 km Odessa line pumps ammonia from Russia to fertiliser and chemical plants as far as Ukraine.

LOHCs are similar to crude oil and diesel, and so could use existing oil pipelines. However, the need to transfer the hydrogen carrier back to its place of origin to be re-loaded with hydrogen, either by truck or a parallel pipeline operating in the opposite direction, makes this a complicated and expensive method of transport.

Shipping

Imported hydrogen offers scope for countries to diversify their energy imports, and one result of this is significant interest in using ships to transport hydrogen.

There are currently no ships that can transport pure hydrogen. Such ships would be broadly similar to LNG ships and would require the hydrogen to be liquefied prior to transport. While both the ships and the liquefaction process would entail significant cost, a number of projects are actively looking to develop suitable ships. The expectation is that these ships will be powered by hydrogen that boils off during the journey (around 0.2% of the cargo would likely be consumed per day, similar to the amount of natural gas consumed in LNG carriers). Unless a high-value liquid can be transported in the opposite direction in the same vessel, ships would need to return empty.

Among hydrogen carriers, the most developed in terms of intercontinental transmission is ammonia, which relies on chemical and semi-refrigerated liquefied petroleum gas (LPG) tankers. Trade routes today include transport from the Arabian Gulf and Trinidad and Tobago to Europe and North America. LOHCs would be the easiest form in which to transport hydrogen by ship, because oil product tankers could be used, although the cost of conversion and then reconversion back to hydrogen before use would also need to be taken into consideration. Ships would also need to return with the original carrier, adding to the complexity of supply routes.

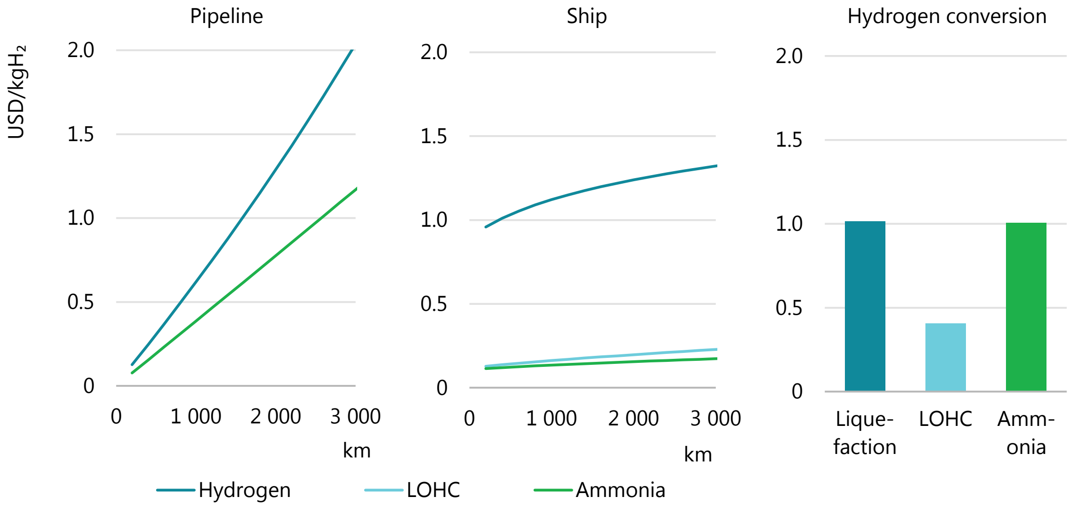
In all cases, shipping supply chains require the necessary infrastructure, including storage tanks, liquefaction and regasification plants, and conversion and reconversion plants, to be built at the loading and receiving terminals as appropriate.

[20] The purity of the H_2 is critical; very pure hydrogen is much more aggressive than 99.5% pure hydrogen, which can be used in hydrogen boilers in homes.

Long-distance transmission costs

For pipelines, taking into account all capital and operating costs, the IEA estimates that it would cost around USD 1/kgH_2 to transport hydrogen as a gas for around 1 500 km (Figure 27). The cost of converting the hydrogen to ammonia is around USD 1/kgH_2 (with some variation between different regions). While it is cheaper to move ammonia by pipeline then hydrogen, these conversion costs mean that the total cost of transmitting ammonia for around 1 500 km is about USD 1.5/kgH_2. As the transmission distance increases, the cost of transporting hydrogen by pipeline escalates faster than the cost for ammonia since a greater number of compressor stations are required. If the transmission distance is 2 500 km the cost of transporting ammonia by pipeline, including the conversion cost, becomes broadly similar to the cost of transporting hydrogen as a gas (around USD 2/kgH_2).

Figure 27. Cost of hydrogen storage and transmission by pipeline and ship, and cost of hydrogen liquefaction and conversion



Notes: Hydrogen transported by pipeline is gaseous; hydrogen transported by ship is liquefied. Costs include the cost of transport and any storage that is required; costs of distribution and reconversion are not included. More information on the assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

The cheapest option to transport hydrogen depends strongly on the mode and distance; the additional costs of conversion need to be weighed against transport savings.

For ships, hydrogen gas must be liquefied or converted prior to transmission. This entails an additional cost to be added to the cost of moving and storing the hydrogen, LOHC or ammonia. For liquid hydrogen, storing the hydrogen at import and export terminals is also relatively expensive. The cost of conversion and moving hydrogen 1 500km by ship as an LOHC is USD 0.6/kgH_2, as ammonia is USD 1.2/kgH_2 and as liquid hydrogen is USD 2/kgH_2. The cost of shipping increases as the transmission distance increases given the need for a greater number of ships, longer voyage distances and additional storage, but not by a significant degree compared to the costs of conversion. The increase in costs at greater distances is also much smaller than is the case for pipelines. As noted above, these costs relate solely to hydrogen transmission; a full cost comparison of the different modes needs to take into account the costs of local distribution and reconversion to hydrogen.

Local distribution

Once the hydrogen has reached the import terminal or transmission hub, local distribution is necessary to deliver it to final users. As with transmission, the best options for doing this for hydrogen, ammonia and LOHCs will depend on volume, distance and end-user needs.

Trucks

Today hydrogen distribution mostly relies on compressed gas trailer trucks for distances less than 300 km. Liquid hydrogen tanker trucks are often used instead where there is reliable demand and the liquefaction costs can be offset by the lower unit costs of hydrogen transport.[21] In both cases, the hydrogen is distributed in tubes that are loaded onto trailers. Trucks can be used to distribute ammonia or LOHCs in a broadly similar way.

In theory a single trailer transporting compressed hydrogen gas can hold up to 1 100 kgH_2 in lightweight composite cylinders (at 500 bar). This weight is rarely achieved in practice, however, as regulations around the world limit the allowable pressure, height, width and weight of tubes that can be transported. In the United States, for example, the pressure limit for steel tubes means that a trailer has a maximum load of 280 kgH_2 (although the US Department of Transport recently approved the manufacture and use of higher-pressure composite storage vessels).

Highly insulated cryogenic tanker trucks can carry up to 4 000 kg of liquefied hydrogen, and are commonly used today for long journeys of up to 4 000 km. These trucks are not suitable for transport above this distance as the hydrogen heats up and causes a rise in pressure.

Around 5 000 kgH_2 in the form of ammonia or 1 700 kgH_2 in the form of LOHC could be moved in a road tanker. In the case of LOHC, a truck would also be needed to transport the carrier molecules back to the original destination after the hydrogen has been extracted from them.

Pipelines

Many modern low-pressure gas distribution pipes are made of polyethylene or fibre-reinforced polymer, and would generally be suitable to transport hydrogen with some minor upgrades. In the United Kingdom almost the entire distribution pipe network, which is about 14 times the length of the country's gas transmission grid, is being replaced with plastic pipes as part of a gas infrastructure upgrade programme. Distribution pipelines for natural gas are extensive in areas with high heating demand, such as northern Europe, the People's Republic of China and North America, reaching into urban areas as well as industrial clusters.

New dedicated hydrogen distribution pipelines would represent a more significant capital cost, especially on the scale required for supplying hydrogen to heat buildings. Distributing ammonia by pipe over long distances would be less costly, but is likely to be attractive only if there is a large demand for ammonia given the costs of converting ammonia back into hydrogen before use. As with transmission, distribution of LOHCs by pipeline is likely to be impractical given the need to return the carrier molecules to their place of origin at the end of the process.

[21] Industry sources indicate that this tipping point is being reached today for hydrogen supply for vehicles in California.

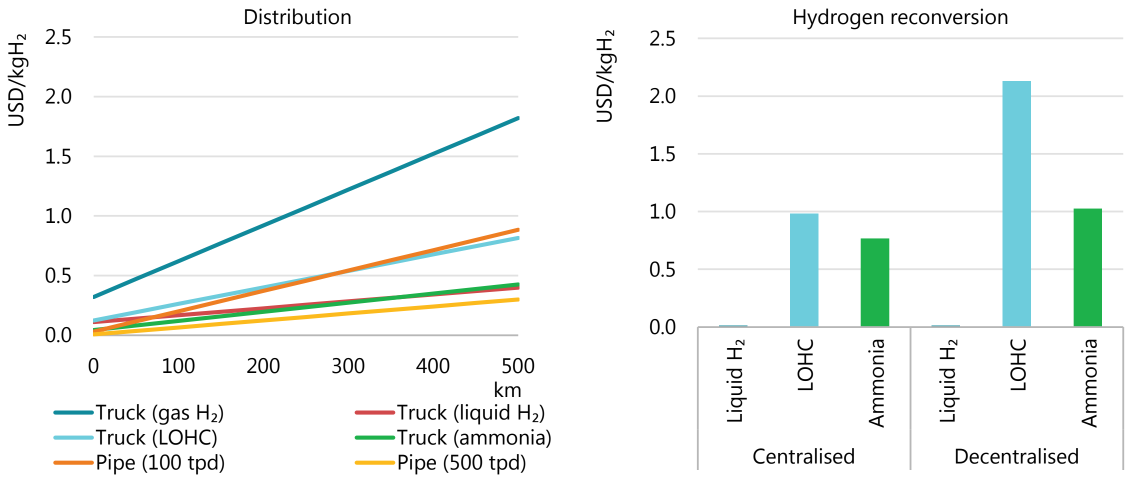
Local distribution costs

While trucks carrying hydrogen gas distribute the majority of hydrogen today, this is a relatively high-cost option (Figure 28). As the distribution distance increases, pipelines become increasingly cost-competitive with trucks. A critical consideration for distribution is how much hydrogen is required by the end user. If large volumes are needed then larger pipes can be used, which reduces the cost of delivery. For example, if 100 tonnes per day (tpd), roughly the amount of hydrogen that would be required by a single 200 MW hydrogen power plant, are required at a location 500 km away from the point of import, then the use of trucks would be cheaper than constructing a pipeline; if 500 tpd are required, then a pipeline would have lower unit costs. Nevertheless, it is reasonable to expect that, over the next decade, compressed gas tube trailers and liquid hydrogen tanks will remain the main distribution modes, just as distribution of gasoline and diesel to geographically dispersed refuelling stations is mostly carried out using trucks today.

Costs also depend strongly on the required end use of the hydrogen. If pure hydrogen is required, then the additional cost of extracting hydrogen from ammonia or an LOHC must be included. The cost of this reconversion depends on the purity of the hydrogen required: if the hydrogen is to be used in fuel cells rather than combusted, then reconversion is more expensive. Furthermore, reconversion costs at the point of end use (for example at a hydrogen refuelling station) is higher than for centralised reconversion (for example at a transmission import terminal).

The IEA estimates that the cost of distributing LOHC by truck for a distance 500 km would be USD 0.8/kgH_2 and the cost of extracting and purifying the hydrogen at the point of end use would be USD 2.1/kgH_2. The total cost of local distribution would therefore be USD 2.9/kgH_2. For ammonia the equivalent cost would be USD 1.5/kgH_2; however, if the ammonia could be used by the final customer without the need for reconversion back to hydrogen, the cost of distribution would considerably lower, at USD 0.4/kgH_2.

Figure 28. Cost of hydrogen distribution to a large centralised facility and cost of reconversion to gaseous hydrogen



Notes: More information on the assumptions is available at www.iea.org/hydrogen2019.
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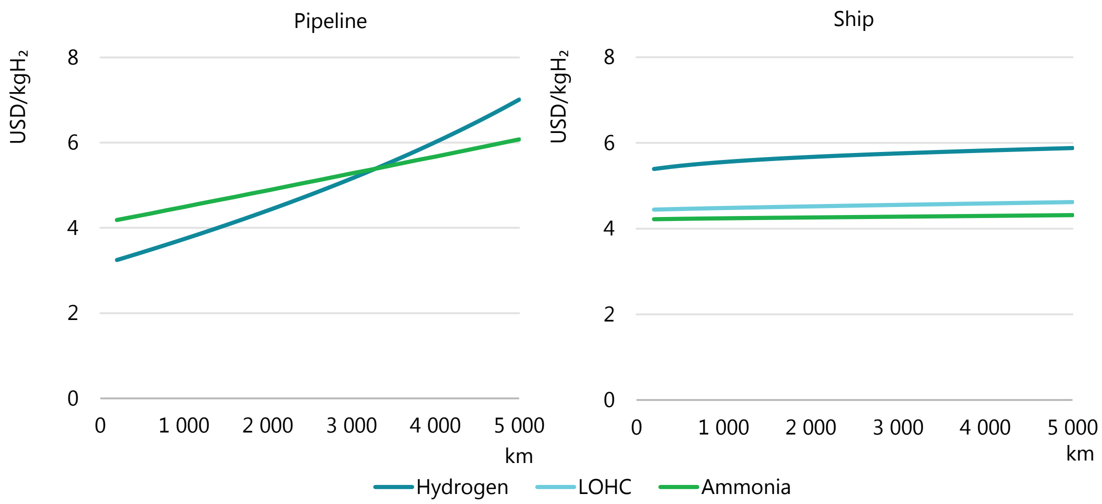
New pipelines are likely to be the cheapest option for distributing large volumes of hydrogen; extracting a pure stream of hydrogen from ammonia and LOHC is expensive.

Total cost of delivering and storing hydrogen

The full cost of hydrogen delivery to end users must take into account all possible stages of the supply chain. The different hydrogen carriers and modes of transport have very different conversion, transmission, distribution, storage and reconversion costs. While one option may be cheaper for a specific part of the value chain, this may be offset by higher costs in another part of the chain. The various technologies involved are also at different degrees of maturity and so have very different future cost reduction potentials. There may be scope for synergies between energy, heat and storage requirements. For example, if the specific value chain in question has higher energy requirements at the export terminal than at the import terminal (e.g. liquid hydrogen), this could improve the relative cost and emission dynamics compared with the reverse case (e.g. LOHCs).

The overall cost of delivering hydrogen will vary according to the infrastructure available in the exporting and importing countries, transmission and distribution distances, the method of transport, and end-use demand. Despite the many uncertainties around most of these cost components, IEA analysis suggests that for inland transmission and distribution, hydrogen gas is the cheaper option for distances below around 3 500 km (Figure 29). Above this distance, ammonia pipelines would be the cheaper option. Comparing transport using pipelines and ships, transmission and distribution of hydrogen gas by pipeline is cheaper for distances below around 1 500 km. Above this distance, LOHC and ammonia transport by ship, which are broadly similar in terms of their full costs, become the cheaper delivery options. The transport and use of ammonia or some LOHCs may, however, give rise to potential safety and public acceptance issues, which could limit their application in some situations.

Figure 29. Full cost of hydrogen delivery to the industrial sector by pipeline or by ship in 2030 for different transmission distances



Notes: Hydrogen production cost = USD 3/kgH_2; assumes distribution of 100 tpd in a pipeline to an end-use site 50 km from the receiving terminal. More information on the assumptions is available at www.iea.org/hydrogen2019.

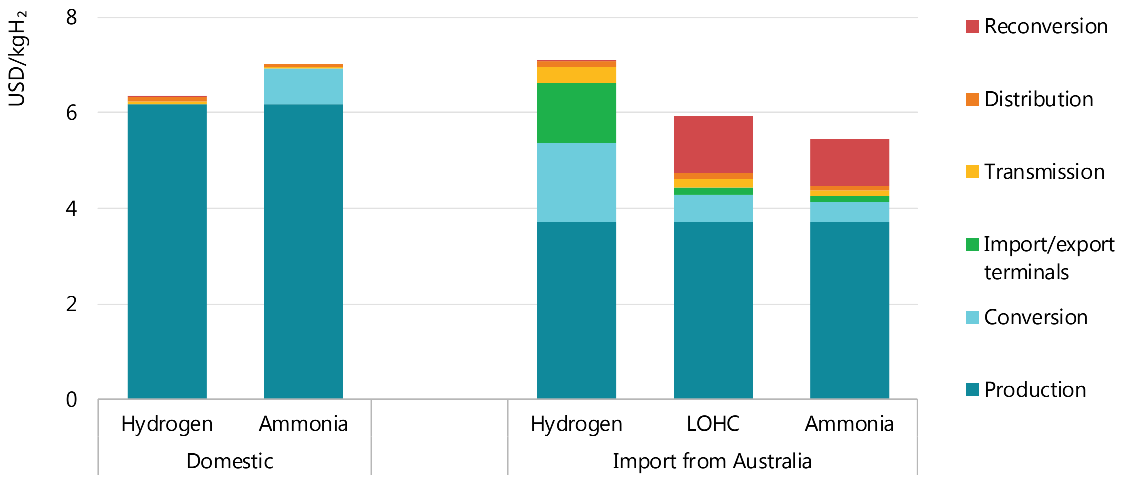
Source: IEA 2019. All rights reserved.

Delivering hydrogen to the industrial sector is cheaper by pipeline for transmission distances below 1 500 km; above this distance LOHC and ammonia are cheaper options.

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, it views hydrogen as a source of energy diversification, emissions reduction and industrial leadership. IEA estimates that, for Japan's industrial sector in 2030, importing electrolytic hydrogen from Australia (around USD 5.5/kgH_2) will be cheaper than domestic production (USD 6.5/kgH_2) (Figure 30). This assumes the production of hydrogen in Australia using combined installations of electrolysers, solar plants and wind farms in a region with high solar and wind resources (Chapter 2) and the subsequent export of this hydrogen to the point of use in Japan as ammonia or LOHC. The total cost of transporting the hydrogen from Australia to Japan (including conversion and reconversion) would be just over USD 1.5/kgH_2, equivalent to USD 45 per MWh. Ammonia would be even more attractive if it could be used directly by the end consumer, thereby avoiding the additional costs of reconverting it back into hydrogen.

The cheapest source of hydrogen would, however, still be substantially more expensive than natural gas. In 2030 the imported natural gas price in Japan is projected to be USD 10/MBtu, equivalent to around USD 1.2/kgH_2. Although the actual cost differential may be slightly smaller than it looks because some hydrogen end-use devices may have a higher efficiency than natural gas devices, further cost reductions would be needed to improve the competitiveness of hydrogen against natural gas systems.

Figure 30. Cost of delivering hydrogen or ammonia produced via electrolysis from Australia to an industrial customer in Japan in 2030



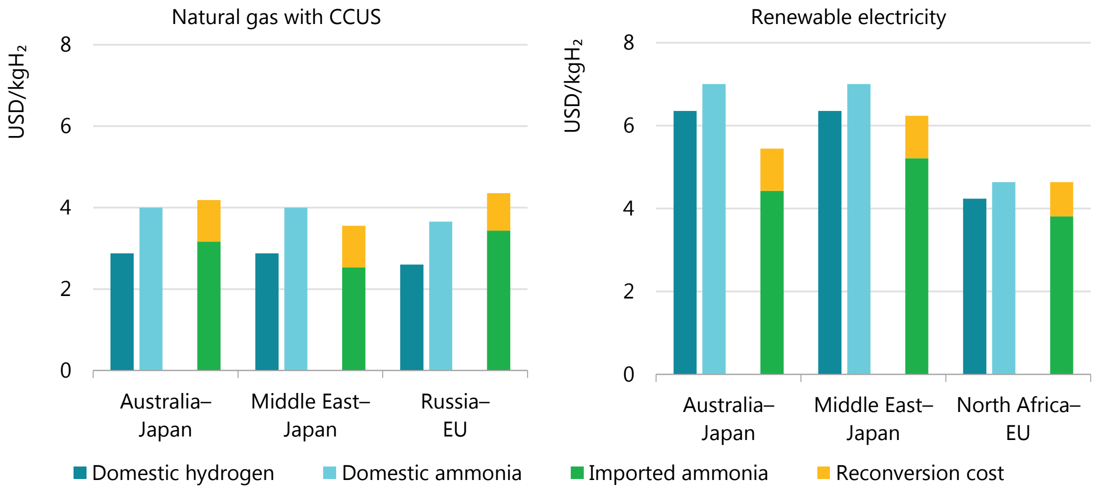
Notes: Assumes distribution of 100 tpd in a pipeline to an end-use site 50 km from the receiving terminal. Storage costs are included in the cost of import and export terminals. More information on the assumptions is available at www.iea.org/hydrogen2019.

Source: IEA analysis based on IAE (2019), "Economical Evaluation and Characteristic Analyses for Energy Carrier Systems" and Reuß (2017), "Seasonal storage and alternative carriers: A flexible hydrogen supply chain model". All rights reserved.

The cost of transport from Australia to Japan could represent between 30% and 45% of the full cost of hydrogen; yet imports of electrolytic hydrogen could still be cheaper than domestic production.

Imports of hydrogen produced from renewable electricity appear to make sense for a number of other possible trade routes too. If ammonia could be used by the end user without the need for reconversion back to hydrogen, then imports would be even cheaper. For example, the cost of importing ammonia from electrolytic hydrogen produced in North Africa into Europe could be cheaper than producing it in Europe (Figure 31).

Figure 31. Comparison of delivered hydrogen costs for domestically produced and imported hydrogen for selected trade routes in 2030



Note: "Domestic" cost is the full cost of hydrogen production and distribution in the importing country (i.e. Japan or the European Union). All costs assume 50 km distribution to a large industrial facility. More information on the assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

Hydrogen imports could be cheaper than domestic production for a number of countries, especially if ammonia can be used by the final customer without the need for reconversion back into hydrogen.

However, for many other possible trade routes, the relatively high cost of hydrogen transmission and distribution means that it will generally be cheaper to produce hydrogen domestically rather than import it. This is because the cost of transport will outweigh differences in the cost of electricity production from renewable sources, or differences in natural gas prices and the cost of CCUS. In Europe, for example, domestic production of low-carbon hydrogen from natural gas equipped with CCUS is likely to be cheaper for industry and power applications than importing low-carbon hydrogen from Russia. Even so, some countries with constrained CO_2 storage or limited untapped renewable resources may still see low-carbon hydrogen imports as worthwhile because of the contribution they make to diversifying their energy systems and reducing their CO_2 emissions.

In the transport sector, centralised reconversion of LOHC or ammonia to produce hydrogen, for example at an import terminal, is generally much cheaper than reconversion at the point of final use, for example at a filling station. However, this needs to be balanced against the higher cost of distributing hydrogen as a liquid or gas.

For hydrogen produced in North Africa and transported to Europe, it is likely to be cheapest to ship the hydrogen as ammonia or LOHC, with the cheapest option for subsequent distribution to a 1 tpd refuelling station[22] depending on the distances involved. For ammonia, if the

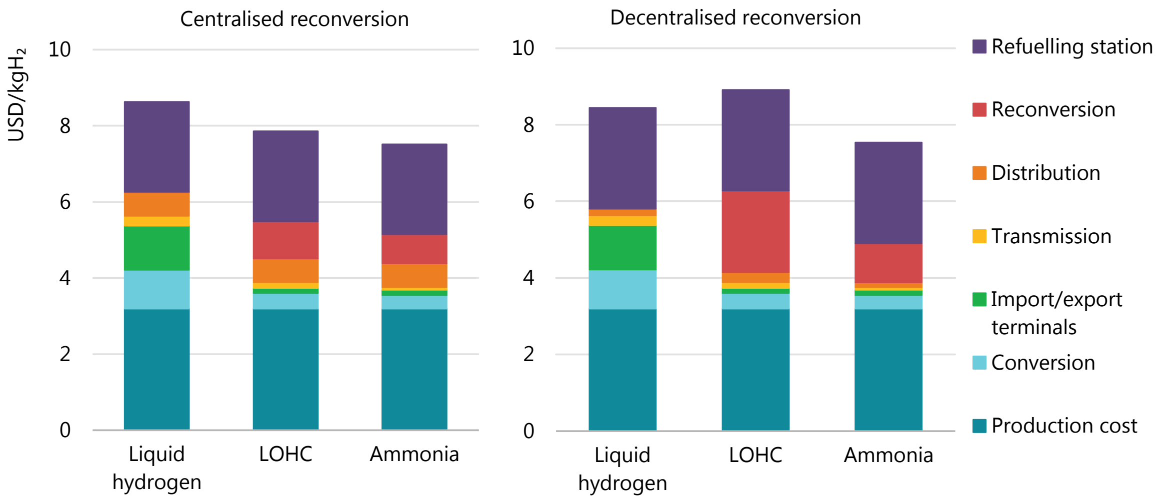
[22] This is approximately the size of large hydrogen refuelling stations considered under the Hydrogen Mobility Initiative in Germany.

distribution distance is below 100 km, then the cheapest option is likely to be to reconvert the ammonia as soon as it has been imported and to distribute the resultant hydrogen using compressed hydrogen gas trucks. If the distribution distance is greater than 100 km, then it is likely to be cheaper to distribute the ammonia in trucks and reconvert them to produce hydrogen at the refuelling station. For LOHC, centralised reconversion is cheaper for distribution distances up to 500 km.

A distribution distance of 100 km would result in a delivered hydrogen price (before tax and margins) between USD 7.5/kgH_2 and USD 9/kgH_2 (Figure 32). Taking into account the higher conversion efficiency of fuel cells compared to internal combustion engines, this would be equivalent to between USD 1.1 and 1.3 per litre of gasoline; this is under current prices at the pump in Europe of around USD 1.4 per litre, although these are prices after taxes.

If existing pipeline infrastructure can be used for hydrogen, the cost of transmission and distribution would be much lower. For example, it is estimated that the cost to convert the gas network of the United Kingdom to supply pure hydrogen to buildings would be around USD 0.6/kgH_2 (CCC, 2018). Given the lower energy density of hydrogen, additional storage capacity would also be required to meet heat demand, which would add a further USD 0.5/kgH_2. In this case, the total cost of hydrogen imported from North Africa and delivered to buildings in the European Union would be around USD 4.5/kgH_2 (USD 135/MWh) for hydrogen produced from natural gas with CCUS, or USD 6/kgH_2 (USD 180/MWh) for electrolytic hydrogen.

Figure 32. Cost of electrolytic hydrogen imports from North Africa supplied to a hydrogen refuelling station in Europe in 2030



Note: Assumes a distribution distance of 100 km. More information on the assumptions is available at www.iea.org/hydrogen2019.
Source: IEA analysis based on IAE (2019), "Economical Evaluation and Characteristic Analyses for Energy Carrier Systems" and Reuß (2019), "A hydrogen supply chain with spatial resolution: Comparative analysis of infrastructure technologies in Germany".

Delivering hydrogen to European refuelling stations in 2030 is likely to cost USD 7.5–9/kgH_2. The choice of centralised or decentralised reconversion depends on distribution distance.

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Chapter 4: Present and potential industrial uses of hydrogen

- **Hydrogen use today is dominated by industrial applications**. The top four single uses of hydrogen today (in both pure and mixed forms) are: oil refining (33%), ammonia production (27%), methanol production (11%) and steel production via the direct reduction of iron ore (3%). Virtually all of this hydrogen is supplied using fossil fuels. These existing uses of hydrogen underpin many aspects of the global economy and our daily lives. Their future growth depends on the evolution of demand for downstream products, notably refined fuels for transport, fertilisers for food production, and construction materials for buildings.

- **More than 60% of hydrogen used in refineries today is produced using natural gas**. Tougher air pollutant standards could increase the use of hydrogen in refining by 7% to 41 MtH_2/yr by 2030, although further policy changes to curb increases in oil demand could dampen the pace of growth. Current global refining capacity is generally thought sufficient to meet rising oil demand, which implies that the majority of future hydrogen demand is likely to arise from existing facilities already equipped with hydrogen production units. This suggests an opportunity for retrofitting CCUS as a suitable option to reduce related emissions.

- **Demand for ammonia and methanol is expected to increase over the short to medium term**, with new capacity additions offering an important opportunity to scale up low-emissions hydrogen pathways. Greater efficiency can reduce overall levels of demand, but this will only partially offset demand growth. Whether via natural gas with CCUS or electrolysis, the technology is available to provide the additional hydrogen demand growth projected for ammonia and methanol (up 14 MtH_2/yr by 2030) in a low-carbon manner. As a priority, substituting low-emissions pathways for any further coal-based production without CCUS would significantly help cut emissions.

- **In the longer term, steel and high-temperature heat production offer vast potential for low-emissions hydrogen demand growth**. Assuming that the technological challenges that currently inhibit the widespread adoption of hydrogen in these areas can be overcome, the key challenges will be reducing costs and scaling up. In the long term it should be technically possible to produce all primary steel with hydrogen, but this would require vast amounts of low-carbon electricity (around 2 500 TWh/yr, or around 10% of global electricity generation today) and would only be economic without policy support at very low electricity prices.

Most hydrogen today is used in three industrial sectors: oil refining, chemicals and iron and steel. Production of hydrogen to meet the needs of these sectors is at a commercial scale and is almost entirely from natural gas, coal and oil today, with associated environmental impacts. However, the technologies are available to avoid the emissions from this fossil fuel use by producing and supplying low-carbon hydrogen. In some cases these alternatives are already deployed where policy and economics are supportive. Table 4 provides an overview of the current and likely future industrial uses of hydrogen.

This chapter explores how hydrogen is currently used in the refining, chemicals and iron and steel sectors. It reviews the current trends for hydrogen demand in these sectors and the options for addressing the emissions related to supplying hydrogen for these existing uses. It concludes with a discussion of the ways in which significant new markets for hydrogen in industrial applications could emerge if hydrogen were used to satisfy a much higher share of the inputs to steelmaking globally or as a source of high-temperature heat with no direct emissions.

Table 4. Summary of hydrogen use in industrial applications and future potential

Sector	Current hydrogen role	2030 hydrogen demand	Long-term demand	Low-carbon hydrogen supply	
				Opportunities	Challenges
Oil refining	Used primarily to remove impurities (e.g. sulphur) from crude oil and upgrade heavier crude. Used in smaller volumes for oil sands and biofuels.	7% increase under existing policies. Boosted by tighter pollutant regulations, but moderated by lower oil demand growth.	Highly dependent on future oil demand but likely to remain a large source of demand in 2050, even in a Paris-compatible pathway.	Retrofit natural gas or coal-based hydrogen with CCUS. Replace merchant hydrogen purchases with hydrogen from low-carbon electricity.	Hydrogen production and use is closely integrated within refining operations, making a tough business case for replacing existing capacity. Hydrogen costs strongly influence refining margins.
Chemical production	Central to ammonia and methanol production, and used in several other smaller-scale chemical processes.	31% increase under existing policies for ammonia and methanol due to economic and population growth.	Hydrogen demand for existing uses set to grow despite materials efficiency (including recycling); new ammonia and methanol demand could arise for clean uses as hydrogen-based fuels.	Retrofit or new-build hydrogen with CCUS. Use low-carbon hydrogen for ammonia and methanol production (urea and methanol will still require a source of carbon).	Competitiveness of low-carbon hydrogen supplies depends on gas and electricity prices. CCUS retrofitting is not a universal option.

Sector	Current hydrogen role	2030 hydrogen demand	Long-term demand	Low-carbon hydrogen supply	
				Opportunities	Challenges
Iron and steel production	7% of primary steel production takes place via the direct reduction of iron (DRI) route, which requires hydrogen. The blast furnace route produces by-product hydrogen as a mixture of gases, which are often used on site.	A doubling under existing policies as the DRI route is used more, relative to the currently dominant blast furnace route.	Steel demand keeps rising, even after accounting for increased materials efficiency. 100% hydrogen-based production could dramatically increase demand for low-carbon hydrogen in the long term.	Retrofit DRI facilities with CCUS. Around 30% of natural gas can be substituted for electrolytic hydrogen in the current DRI route. Fully convert steel plants to utilise hydrogen as the key reducing agent.	All options require higher production costs and/or changes to processes. Direct applications of CCUS are usually projected to have lower costs, although these are highly uncertain. Long-term competition from direct electrification.
High-temperature heat (excluding chemicals and iron and steel)	Virtually no dedicated hydrogen production for generating heat. Some limited use of hydrogen-containing off-gases from the iron and steel and chemical sectors.	9% increase in high-temperature heat demand under existing policies. No additional hydrogen use without significant policy support.	Heat demand likely to rise further, providing an opportunity for hydrogen if it can compete on cost in the prevailing policy environment.	Hydrogen from any source could replace natural gas, e.g. in industrial clusters or near hydrogen pipelines. Blends with natural gas are more straightforward but less environmentally beneficial.	Hydrogen expected to compete poorly with biomass and direct CCUS in general, but may prove competitive with direct electrification. Full fuel switches, or CCUS, tend to entail significant investment.

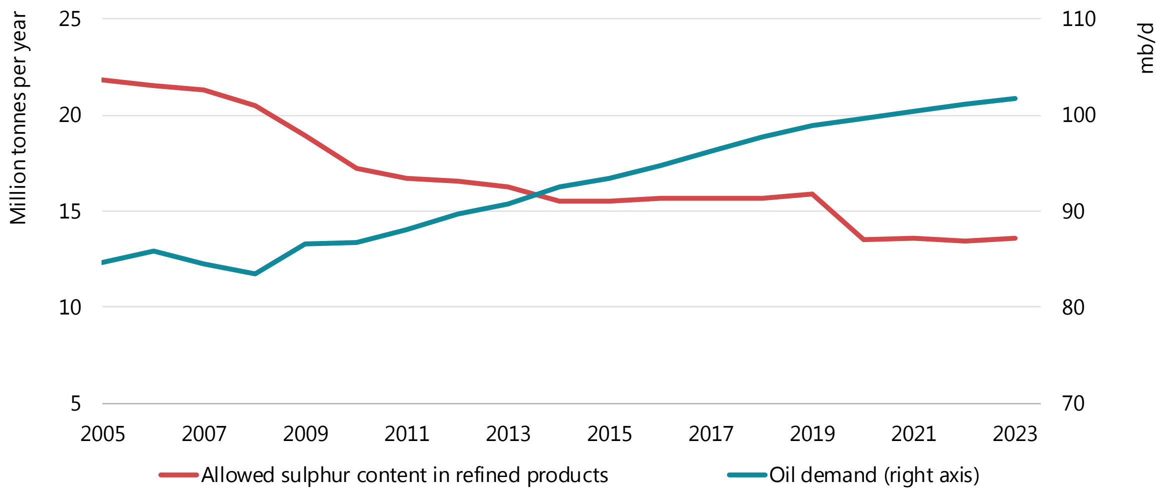
Hydrogen in oil refining

Oil refining – turning crude oil into various end-user products such as transport fuels and petrochemical feedstock – is one of the largest users of hydrogen today. Some 38 MtH_2/yr, or 33% of the total global demand for hydrogen (in both pure and mixed forms), is consumed by refineries as feedstock, reagent and energy source. Around two-thirds of this hydrogen is produced in dedicated facilities at refineries or acquired from merchant suppliers (together called "on-purpose" supply). Hydrogen use is responsible for around 20% of total refinery emissions, and produces around 230 $MtCO_2$/yr. Refineries' existing large-scale demand for hydrogen is set to grow as regulations for sulphur content of oil products tighten. This provides a potential early market for hydrogen from cleaner pathways, which could lower the emissions intensity of transport fuels.

How does the refining sector use hydrogen today?

Hydrotreatment and hydrocracking are the main hydrogen-consuming processes in the refinery. Hydrotreatment is used to remove impurities, especially sulphur (it is often simply referred to as desulphurisation)[23] and accounts for a large share of refinery hydrogen use globally. Today refineries remove around 70% of naturally incurring sulphur from crude oils. With concerns about air quality increasing, there is growing regulatory pressure to further lower the sulphur content in final products. By 2020 40% less sulphur will be allowed in refined products than in 2005 despite the continued growth in demand (Figure 33).

Figure 33. Allowed sulphur content in oil products



Note: mb/d = million barrels per day.
Source: IEA (2018a), *World Energy Outlook 2018*.

The quantity of allowed sulphur in refined products continues to decrease, while oil demand continues to increase.

Hydrocracking is a process that uses hydrogen to upgrade heavy residual oils into higher-value oil products. Demand for light and middle distillate products is growing and demand for heavy residual oil is declining, leading to an increase in the use of hydrocracking. In addition to hydrotreatment and hydrocracking, some hydrogen that is used or produced by refineries cannot be economically recovered and is burned as fuel as part of a mixture of waste gases.

The United States, the People's Republic of China ("China") and Europe are the largest consumers of hydrogen in refineries. The three regions represent around half of total refinery hydrogen consumption, reflecting the volume of crude oil they process and the stringency of their product quality standards.

Hydrogen is also used for upgrading oil sands and hydrotreating biofuels. For oil sands, the amount of hydrogen needed to remove sulphur from the raw bitumen varies considerably depending on the upgrading technology and the quality of the synthetic crude oil produced.

[23] It also treats other chemical components – nitrogen- and oxygen-containing compounds or metals – that are unfavourable to fuel quality and/or refining equipment, such as catalysts.

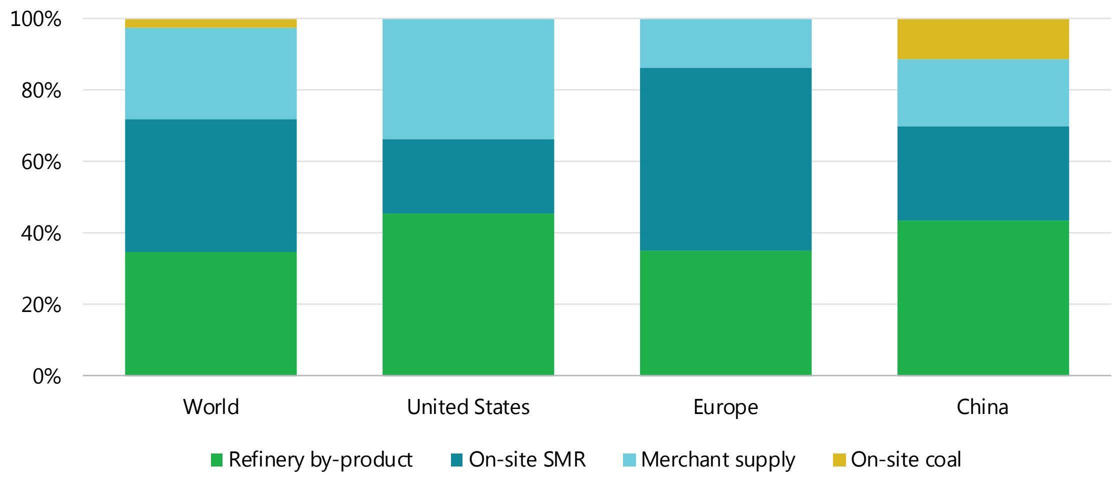
Overall around 10 kg of hydrogen is used per tonne of bitumen processed.[24] The resulting synthetic crude oil still needs to be refined at a refinery, using hydrogen. For biofuels, hydrotreatment removes oxygen and improves the fuel quality of vegetable oils and animal fats processed into diesel substitutes. This process requires around 38 kg of hydrogen per tonne of biodiesel produced, but no further hydrogen is needed in subsequent refining steps.

Sources and costs of hydrogen for refinery use

Globally, refinery hydrogen demand is met through the use of on-site by-products, dedicated on-site production, or merchant supply (Figure 34).

On-site by-product hydrogen comes largely from catalytic naphtha reforming, a process that produces high-octane gasoline blending components and generates hydrogen at the same time. Refineries with integrated petrochemical operations also derive by-product hydrogen from steam cracking. However, on-site by-product hydrogen is unable to fully cover refinery hydrogen demand, except in small refineries running on very low sulphur crude oils and with relatively low yields of road transport fuels. On average, on-site by-product hydrogen meets one-third of refinery hydrogen demand. The gap needs to be met, either by dedicated on-site production (about 40% globally) or procurement from merchant suppliers (around a quarter).

Figure 34. Sources of hydrogen supply for refineries in selected regions, 2018



Notes: SMR = steam methane reformer. For China, refinery by-product also includes hydrogen produced from refinery-integrated crackers.
Source: IEA 2019. All rights reserved.

Refinery hydrogen by-product covers only a third of hydrogen requirements, with the gap filled by dedicated on-site production and merchant supply.

Most dedicated on-site production uses natural gas feedstock, but light fractions of oil distillation and heavier feedstocks – petroleum coke, vacuum residues and coal – are also used in some regions. Use of heavier feedstocks is mostly restricted to India and China, where

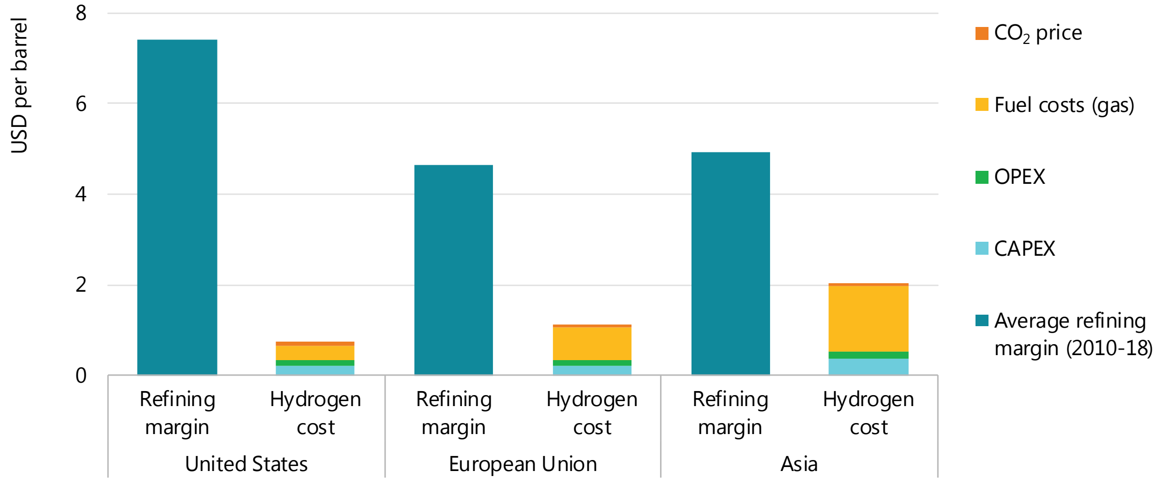
[24] Around 0.6 MtH_2/yr is used to process 1 mb/d of bitumen.

gas needs to be imported. Coal gasification is routinely included in new refinery setups in China as a main or auxiliary hydrogen production unit.

Merchant supply of hydrogen is an option in densely industrialised areas where developed hydrogen pipeline infrastructure exists, such as the US Gulf Coast and Europe's Amsterdam-Rotterdam-Antwerp hub. As with dedicated on-site production, merchant hydrogen is mostly produced from natural gas, although a certain amount also comes from chemical processes, where it is a by-product of operations such as steam cracking and chlorine production. In regions such as the US Gulf Coast, merchant hydrogen can meet over a third of total hydrogen demand.

Hydrogen production costs vary widely, largely reflecting differences in natural gas prices. US production costs are among the world's lowest, while costs are substantially higher in Europe and Asia. In the United States, hydrogen costs amount to around USD 1.1/kgH_2 or USD 0.7 per barrel of oil refined. This may seem a relatively small cost component for refineries overall, for example in comparison with crude costs, but even a small cost advantage in hydrogen costs can have a notable impact on refining margins, which are generally thin in what is a very competitive market (Figure 35).

Figure 35. Hydrogen production costs compared to refining margins, 2018



Note: Based on production costs via natural-gas based SMR. More information on the assumptions is available at www.iea.org/hydrogen2019.
Source: IEA 2019. All rights reserved.

In many regions, hydrogen costs are a significant drain on refinery profits.

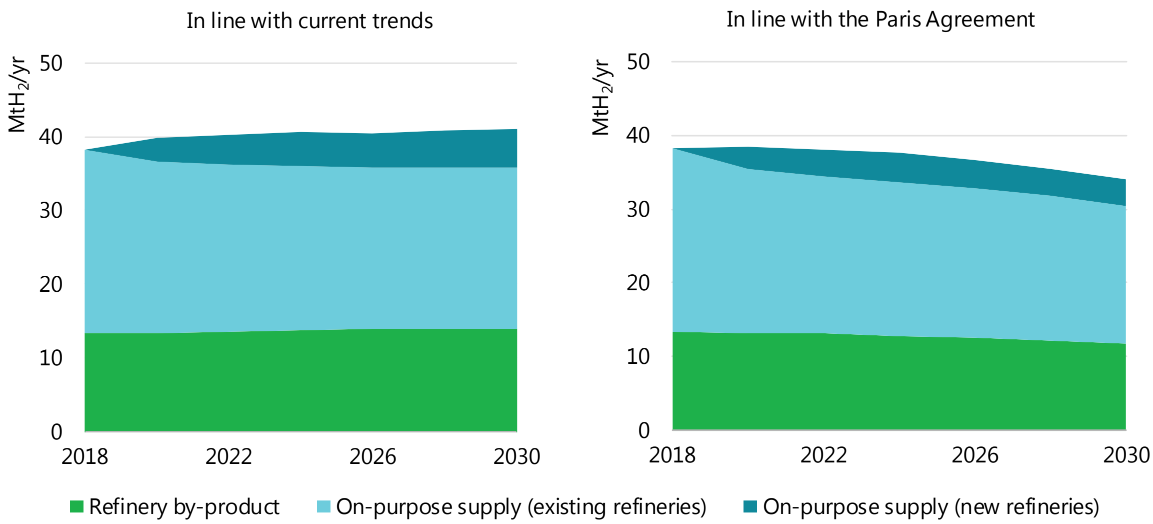
Potential for future hydrogen demand in oil refining

In recent decades, refinery hydrogen demand has grown substantially as a result of growing refining activity and rising requirements for hydrotreating and hydrocracking. This trend is set to continue as fuel specifications globally further reduce acceptable levels of sulphur content. Many countries, including China, have already reduced sulphur content requirements in road transport fuels such as gasoline or diesel to under 0.0015%, and others may introduce similar standards. The International Maritime Organization has also introduced new bunker fuel regulations that limit the sulphur content of marine fuels to no more than 0.5% from 2020 (IEA, 2019a), and this is likely to lead to a significant increase in hydrogen requirements for marine fuel production. However, hydrogen demand is also a function of inherent sulphur content in crude oils. The average quality of crude oil supply has been getting lighter and sweeter in recent years, due primarily to surging US tight oil output, and this is likely to moderate the need for hydrogen to some degree. Under current trends, overall hydrogen demand in refineries is set to grow by 7% to 41 MtH_2/yr in 2030.

Beyond 2030 current trends and policies suggest the pace of hydrogen demand growth to slow down, as the scope to tighten product quality standards decreases and as oil demand for transport fuels is affected by a combination of efficiency improvements and electrification. Refiners are also likely to increase the efficiency of hydrogen recovery from waste refinery gases, lowering requirements for additional hydrogen production. Refinery hydrogen demand would decline in a scenario compatible with the objectives of the Paris Agreement, with the impact of declining oil demand more than offsetting that of higher hydrogen intensity.

Irrespective of the future trajectory of global energy demand, one common aspect is the dominant share of existing refineries in projected hydrogen demand. There is already sufficient refining capacity globally to fulfil the expected need for oil products. Together with the long lifetime of refineries, this limits the scope for substantial addition of new refining capacity. As a result, some 80–90% of cumulative on-purpose hydrogen supply (including both dedicated on-site production and merchant procurement) between today and 2030 would come from existing refineries in both scenarios (Figure 36).

Figure 36. Future hydrogen demand in oil refining under two different pathways



Note: On-purpose supply refers to both dedicated on-site production and merchant procurement.
Source: IEA 2019. All rights reserved.

Future hydrogen demand in the refining sector comes mostly from today's existing capacity.

Meeting future hydrogen demand in oil refining while reducing emissions

Hydrogen production – unless supplied as a by-product of refining operations – currently results in considerable CO_2 emissions. Globally the production of hydrogen for use in refineries contributes some 230 $MtCO_2$/yr emissions, which is around 20% of total refinery emissions.

Demand and emissions are all set to rise in future. If future demand growth is met using coal, which is widely used without CCUS to produce hydrogen in countries such as China, the level of CO_2 emissions would further increase.

Producing hydrogen in a cleaner way is therefore vital to achieving a significant reduction in emissions from refining operations. Other key measures – such as energy efficiency and fuel switching away from emission-intensive fuels – have already been widely adopted in many refineries, limiting opportunities for further emissions reduction. Against this background, together with sizeable demand already existing today, the refining industry offers a potential early market for low-carbon hydrogen.

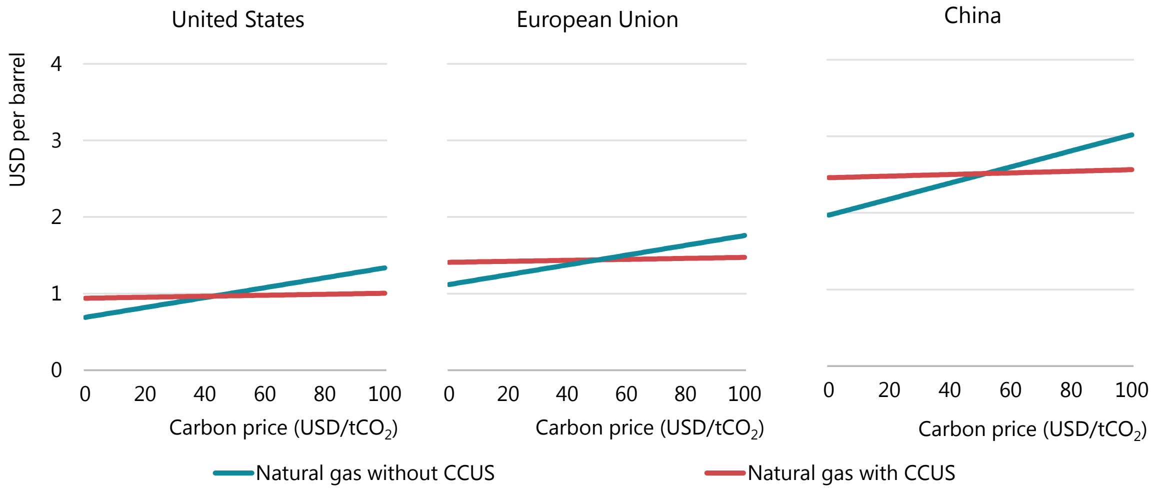
Cost competitiveness of cleaner pathways

There are two main cleaner pathways to hydrogen production for refineries: equipping coal- or natural gas-based hydrogen production facilities with CCUS; and using electrolytic hydrogen from low-carbon electricity. Given that the bulk of future hydrogen demand comes from existing refineries and that most refineries are already equipped with SMR units, natural gas with CCUS offers a more obvious route to low-carbon hydrogen than does renewables-based electrolysis. The incremental costs for the production of low-carbon hydrogen are limited to CCUS facilities, which makes natural gas with CCUS more competitive than electricity-based options, and capturing CO_2 emissions from an SMR unit represents one of the lowest-cost opportunities to apply CCUS in a refinery because much of this CO_2 is emitted in a highly concentrated stream.

However, despite the continued decline of technology costs for CCUS, the large-scale adoption of CCUS at hydrogen production units in refineries needs a helping hand from policy makers, especially given the tight margins and highly competitive nature of the refining industry. Introducing CCUS would add an incremental cost of some USD 0.25–0.5/barrel, which is higher than today's carbon price levels (zero to USD 0.1/barrel).[25] This implies that refiners are likely to be inclined to pay CO_2 prices rather than to direct effort to capturing and storing CO_2. Higher carbon prices, or equivalent policy incentives, would change the picture. A carbon price higher than USD 50/tCO_2, for example, would make natural gas with CCUS economically attractive in most regions and could trigger a wider deployment of CCUS at SMR facilities (Figure 37). In the United States a tax incentive known as "45Q" is worth up to USD 50/tCO_2 for CCUS operations online by 2026. The case for investment would be further strengthened if captured CO_2 could be sold to industrial users or upstream oil companies for enhanced oil recovery (EOR). Low-carbon fuel standards could also help spur CCUS: standards of this kind have already been introduced in Canada, Europe and some US states, including California (Box 8).

[25] The incremental costs for CCUS installation are also higher than the 2030 carbon price levels envisaged in the IEA New Policies Scenario, which are around USD 0.2/barrel.

Figure 37. Hydrogen production costs from natural gas with and without CCUS by region under different carbon prices, 2030



Notes: To show hydrogen costs in terms of their impact on refinery costs, 0.64, 0.63 and 1.04 kgH2/barrel are used for conversion for the United States, European Union and China respectively. More detail on the assumptions available at www.iea.org/hydrogen2019.
Source: IEA 2019. All rights reserved.

CCUS would become economically attractive at refineries in most regions if CO2 prices were above USD 50/tCO_2.

The costs of introducing CCUS also depend on the costs of CO2 storage, which means that the successful introduction of CCUS is contingent on CO_2 storage being available and accessible with known and manageable costs and risks. Cost reduction efforts therefore need to be complemented by policy measures to bring about the building of CO_2 storage infrastructure and the development of operating businesses in the appropriate locations. This would also have the benefit of laying the ground for the adoption of CCUS in other industries.

A number of refineries have already installed CCUS facilities for hydrogen production. Some of the emissions from the 400 thousand barrels per day (kb/d) Pernis refinery in Rotterdam are captured, transported and used in nearby greenhouses. In 2017 Air Product's Port Arthur project in Texas completed its demonstration phase; it captures CO_2 for EOR operations at the West Hastings oil field. In France, Air Liquide's Port Jerome project captures and sells CO_2, and Hokkaido Refinery in Japan has put in place pilot CCUS facilities. There is also one bitumen upgrader equipped with CCUS in operation today – the Quest project in Canada – which captures around 20% of the emissions from the 255 kb/d upgrader. In total, the four CCUS plants which are now in operation in refineries have the capacity to produce over 150 ktH_2/yr of low-carbon hydrogen.[26]

Potential also exists at refineries for electrolytic hydrogen to replace dedicated hydrogen production from natural gas or coal. For the moment no refineries are using electrolytic hydrogen, but Shell's 200 kb/d Rheinland refinery in Germany has announced a 10 MW electrolyser project for 2020 that will supply around 1 ktH_2, or 1% of the refinery's hydrogen needs. Heide, a small refinery near Hamburg, Germany, has announced a 30 MW electrolyser paired with offshore wind power to replace purchases of up to 3 ktH_2/yr. BP, Nouryon and the

[26] Calculated by multiplying hydrogen production capacity by the CO_2 capture rate to label a fraction of the capacity as "low carbon".

Port of Rotterdam Authority are also jointly assessing the feasibility of a 250 MW electrolysis plant for the production of 45 ktH_2/yr for the BP refinery in Rotterdam. Despite this progress, policy support is going to be needed if electrolysis is to take off at scale.

In certain instances there is also scope to avoid some current hydrogen-related emissions through "outside-gate collaboration" (CIEP, 2018). Petrochemical steam crackers tend to generate a surplus of hydrogen that could be used in refineries; conversely, the low-value fuel gases produced by refineries can be used in steam crackers. Incentivising the development of the necessary infrastructure to exchange these products within industrial clusters would help to reduce overall emissions.

Box 8. Can California's Low Carbon Fuel Standard support low-carbon hydrogen?

In 2007 California enacted a world-first mandate to reduce the carbon intensity of transport fuel used in the state. It requires oil refiners and distributors to meet a declining target for the complete lifecycle greenhouse gas emissions of transport fuels so as to deliver a 20% reduction in carbon intensity by 2030, compared to a 2010 baseline. Policies that take a similar approach are now in place in the European Union, Oregon and Canada, where a clean fuel standard is under development for all fuels and end uses.

Amendments in California in 2019 expanded the range of eligible abatement technologies, and introduced incentives to develop hydrogen refuelling and electric vehicle fast-charging stations. The amendments also included measures to enable carbon capture and sequestration operators to receive credit for emission reductions, including via direct air capture of CO_2 outside California.

California's Low Carbon Fuel Standard (LCFS) is a market-based standard with tradeable credits. Suppliers of fuel with a carbon intensity above the target generate deficits and must buy credits equivalent to their deficit from suppliers of lower carbon fuels. This system motivates fuel suppliers to keep improving their carbon intensity, even if they are already producing a renewable fuel or charging electric vehicles. Credits are issued in units of tonnes of CO_2 equivalent, relative to a standard value for gasoline, diesel or jet fuel (CARB, 2019a). Over time the diversity of sources of credits has increased. In 2011 bioethanol suppliers received 80% of credits. In 2018 supply of renewable diesel, biodiesel, electricity and biomethane generated over 60% of credits. The average price for the 13 million credit transactions in 2018 was USD 160/tCO_2.

Hydrogen can generate credits in a variety of ways, which include:

- Operation of a hydrogen refuelling station
- Supply of hydrogen to fuel cell electric vehicles (FCEVs) or forklifts
- Supply of petroleum products produced using low-carbon hydrogen, for example from CCUS, steam-reforming of biomethane, or electrolysis in refineries
- Supply of renewable diesel or alternative jet fuel produced using low-carbon hydrogen input
- Use of an electrolyser at times of day with low carbon intensity electricity.

The value of a unit of hydrogen varies according to use and life cycle CO_2 emissions. For example, at USD 160/tCO_2 one kg of low-carbon hydrogen with zero upstream emissions would be worth roughly USD 4.3 if used directly in a fuel cell car, USD 3.6 if used directly in a fuel cell forklift, or

USD 2.3 if replacing natural gas-based hydrogen in a refinery or renewable diesel facility. Most LCFS credits generated by hydrogen in 2018 were for the use of natural gas-derived hydrogen in vehicles; these would be worth USD 2.2/kgH_2 at USD 160/tCO_2 (CARB, 2019b).

Fuel suppliers have not yet used low-carbon hydrogen at refineries to generate credits to meet their obligations. One facility generates credits by fuelling buses with hydrogen produced via electrolysis using a mix of solar and grid electricity. Several renewable diesel facilities using hydrogen are certified. At USD 160/tCO_2 the price of credits is above the cost of using CCUS for hydrogen production from natural gas. The LCFS also interacts with other policy instruments in California, such as the Zero Emissions Vehicle mandate, the cap-and-trade system, and infrastructure grants and tax credits for FCEVs, and this has the potential to raise the profitability of eligible projects.

Hydrogen in the chemical sector

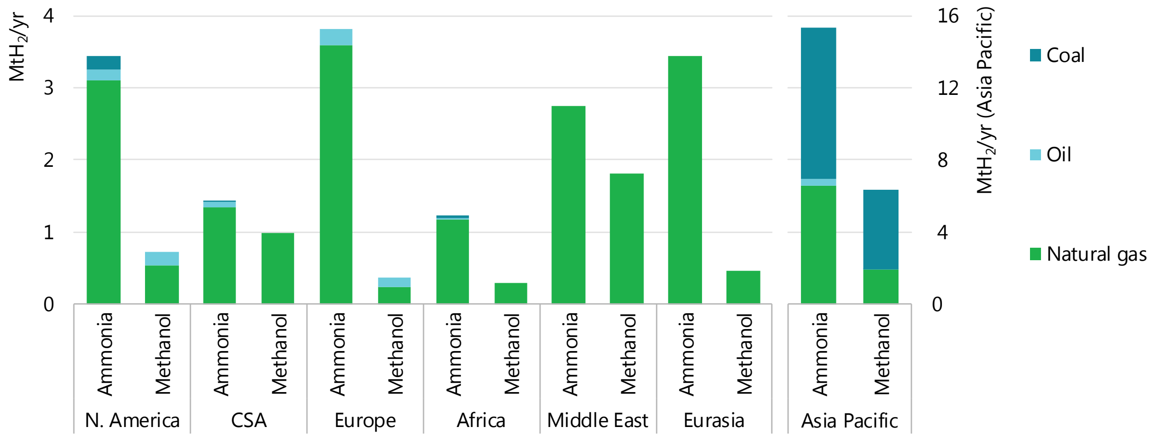
The chemical sector accounts for the second- and third-largest sources of demand for hydrogen today: ammonia at 31 MtH_2/yr and methanol at 12 MtH_2/yr. Other comparatively minor applications take its overall demand to 46 MtH_2/yr, or 40% of total hydrogen demand in both pure and mixed forms. It is also a large producer of by-product hydrogen, which is both consumed within the sector itself and distributed for use elsewhere. The vast majority of the hydrogen that the chemical sector consumes is produced using fossil fuels, and this generates considerable quantities of greenhouse gas emissions. Reducing the level of emissions represents an important challenge for the sustainability of the sector's energy use, and a significant opportunity to make use of low-carbon hydrogen.

How does the chemical sector use hydrogen today?

The chemical sector produces a complex array of outputs, from plastics and fertilisers to solvents and explosives. This section focuses primarily on ammonia and methanol, and to a lesser extent on ethylene, propylene, benzene, toluene and mixed xylenes. These seven "primary chemicals" account for around two-thirds of the chemical sector's energy consumption, and the vast majority of its demand for energy products as raw material inputs (so-called "feedstocks").

Hydrogen is part of the molecular structure of almost all industrial chemicals, but only some primary chemicals require large quantities of dedicated hydrogen production for use as feedstock, notably ammonia and methanol (Figure 38). More than 31 MtH_2/yr of hydrogen are used as feedstock to produce ammonia, and more than 12 MtH_2/yr to produce methanol. A further 2 MtH_2/yr are consumed in comparatively small-volume processes (for example in hydrogen peroxide and cyclohexane production), but most of this is supplied from by-product hydrogen generated within the sector.

Figure 38. Hydrogen demand for ammonia and methanol production in 2018



Notes: Only production routes comprising > 1 Mt/yr of primary chemical production are included; oil refers to refined oil products including naphtha and LPG. CSA = Central and South America. Data for 2018 are estimates based on previous years' figures from the sources below.

Sources: IFA (2019), *International Fertilizer Association Database*; WoodMackenzie (2018), *Methanol Production and Supply Database*.

Today natural gas accounts for 65% of ammonia and methanol production; coal-based production accounts for 30%.

Fossil fuels have long been a convenient and cost-effective source of both the hydrogen and carbon for ammonia and methanol production. In 2018 around 270 Mtoe/yr of fossil fuels were used to produce the hydrogen for these two products,[27] roughly equivalent to the combined oil demand of Brazil and the Russian Federation. Because production via natural gas (reforming) is more efficient than via coal (gasification), the former accounts for 65% of hydrogen production, but less than 55% of the energy inputs required to produce it. The differing regional prices of gas and coal are also a key determining factor in the choice of process route. Almost all hydrogen from coal for use in the chemical sector is produced and used in China.

Ammonia is mostly used in the manufacture of fertilisers such as urea and ammonium nitrate (around 80%). The remainder is used for industrial applications such as explosives, synthetic fibres and other specialty materials, which are an increasingly important source of demand.

Methanol is used for a diverse range of industrial applications, including the manufacture of formaldehyde, methyl methacrylate and various solvents. Methanol is also used in the production of several other industrial chemicals, and for the methanol-to-gasoline process that produces gasoline from both natural gas and coal, which has proven attractive in regions with abundant coal or gas reserves but with little or no domestic oil production. This is one of the fuel applications of methanol, whether blended in pure form or used after further conversion (e.g. to methyl-tert butlyl ether), that account for around a third of the chemical's use globally (Levi and Cullen, 2018; Methanol Institute, 2019). The development of methanol-to-olefins and methanol-to-aromatics technology has opened up an indirect route from methanol to high-value chemicals (HVCs), and thus to plastics. Methanol-to-olefins technology is currently deployed at commercial scale in China, accounting for 9 million tonnes per year (Mt/yr) or 18%

[27] Including feedstock and process energy requirements.

of domestic HVC production in 2018. Methanol-to-aromatics, which is used to produce more complex HVC molecules, is currently still in the demonstration phase.

Unlike ammonia and methanol, HVCs – the precursors of most plastics – are produced mostly from oil products such as ethane, liquefied petroleum gas and naphtha. HVCs produced directly from oil products do not require hydrogen feedstock, but their production generates by-product hydrogen that can be used in oil refining and other chemical sector operations, such as the upgrading of other cracker by-products. Steam cracking and propane dehydrogenation processes for HVC manufacture produce around 18 MtH_2/yr as a by-product globally. HVC demand is growing at a faster rate than refined oil product demand, which means that an increasing quantity of this by-product hydrogen could be available for use in other industries.

Chlor-alkali processes are another source of by-product hydrogen in the chemical sector, supplying around 2 MtH_2/yr. While by-product hydrogen generated in the steam cracking process stems from oil products (mainly ethane and naphtha), the chlor-alkali process is a form of electrolysis (of brine) and is powered by electricity. Smaller volumes of by-product hydrogen are also produced from other processes such as styrene production.

How is demand for hydrogen likely to develop in future?

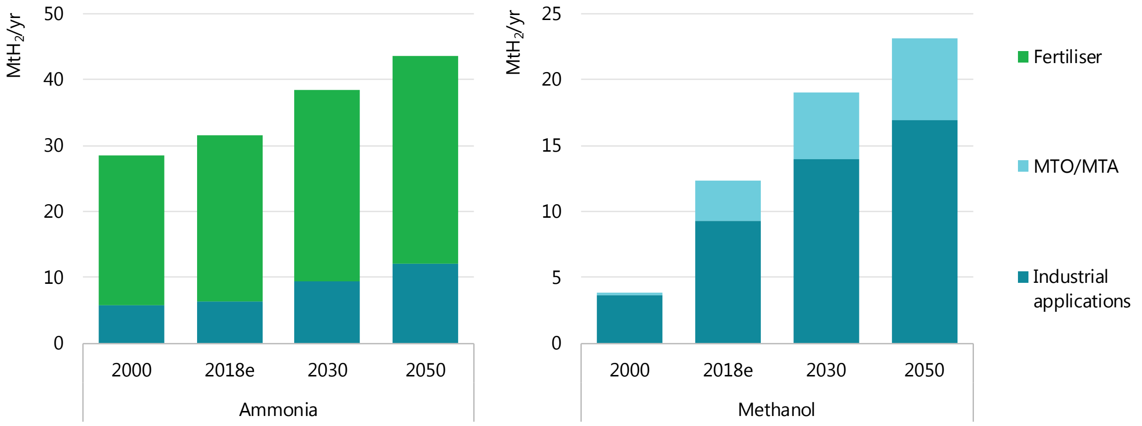
Demand for hydrogen for primary chemical production is set to increase from 44 Mt/yr today to 57 Mt/yr by 2030 as demand for ammonia and methanol grows (Figure 39).[28] Demand for ammonia for existing applications is set to increase by 1.7% per year between 2018 and 2030 and to continue to rise thereafter. The share represented by demand for industrial applications grows more quickly during this period; that for nitrogen-based fertilisers is likely to start to plateau or even decline in many regions after 2030.

Demand for methanol for existing applications is set to grow at 3.6% per year between 2018 and 2030. The methanol-to-olefins/methanol-to-aromatics demand segment grows more quickly than the total, at 4.1% per year over the same period, with nearly all this growth coming from China. This rate of growth would require 19 MtH_2/yr for methanol production for these existing applications by 2030, compared with 12 MtH_2/yr today.

Together with energy efficiency measures, materials efficiency strategies are an important way of reducing emissions in IEA decarbonisation scenarios and could reduce these increases in demand (IEA, 2019b; Allwood and Cullen, 2012). Recycling and reusing plastics and other materials could reduce the amount of future primary chemical production required, although this would be likely to have a less pronounced impact on ammonia and methanol demand than on demand for other primary chemicals such as ethylene. Improving the efficiency with which fertiliser is used could also reduce future demand for chemicals. Specific policies have been announced in some countries to limit fertiliser use, such as the target for zero growth from current levels in China (Shuqin and Fang, 2018).

[28] The most recent IEA publication exploring the future evolution of the chemical sector is IEA (2018b), *The Future of Petrochemicals*.

Figure 39. Hydrogen demand for primary chemical production for existing applications under current trends



Notes: MTO = methanol-to-olefins; MTA = methanol-to-aromatics. Industrial applications for methanol include current fuel additive uses (e.g. methyl-tert-butyl-ether) and thermoset plastics (e.g. phenol formaldehyde). Industrial applications for ammonia include explosives (e.g. ammonium nitrate) and plastics (e.g. urea formaldehyde). Demand figures for 2030 and 2050 are consistent with those of the Reference Technology Scenario (IEA, 2018b), in which current trends are maintained. Data for 2018 are estimates based on previous years' figures from the sources below.

Sources: IFA (2019), *International Fertilizer Association Database*; WoodMackenzie (2018), *Methanol Production and Supply Database*.

Hydrogen demand for ammonia and methanol for existing applications is set to rise.

Conversely, demand for ammonia and methanol could rise further if these chemicals were to become established as energy carriers for the transmission, distribution and storage of hydrogen, facilitating its use in new applications, or if they were to be used as fuels in their own right (see Chapters 2 and 3). If these new applications were to become widespread, the chemical sector could evolve to share the role that refineries play today in providing energy to downstream users.

Without any change in the current economics or regulation of production, current growth trajectories for chemical products are likely to lead to a growth in hydrogen production from natural gas and coal without the application of CCUS. Projecting forward current trends, this growth would cause total direct CO_2 emissions from ammonia and methanol production to rise by around 20% between 2018 and 2030.

Meeting future hydrogen demand in the chemical sector while reducing emissions

The global production of ammonia and methanol currently generates CO_2 emissions of around 630 $MtCO_2$/yr.[29] The global average direct emissions intensity of ammonia production is 2.4 tonnes of CO_2 per tonne (tCO_2/t), with average intensities for major regions in the range of 1.6–2.7 tCO_2/t. New gas-based plants in the Asia Pacific region tend to be at the lower end of this range, whereas pure coal-based production (around 4 tCO_2/t), widespread in China, constitutes the most CO_2-intensive production route. For methanol the global average figure

[29] This excludes the approximately 130 $MtCO_2$/yr of concentrated CO_2 streams that are separated and utilised to manufacture urea. A large proportion of this embedded CO_2 is re-emitted in the agricultural sector when urea is applied to soils.

is 2.3 tCO_2/t, with average intensities for major regions in the range of 0.8–3.1 tCO_2/t. As for ammonia, production based purely on coal is the most emissions-intensive pathway.

The production of HVCs is responsible for a further 250 $MtCO_2$/yr of CO_2 emissions. However, the key mitigation options currently under development (including the direct application of CCUS to existing process units, dry methane reforming and steam cracker electrification) do not involve additional dedicated hydrogen production. HVCs could also be produced from methanol, but this would similarly not involve additional hydrogen production beyond that required for the methanol. The focus in this section is therefore on ammonia and methanol.

Alternative process technologies and feedstocks could meet growing demand for large quantities of dedicated hydrogen feedstock in the chemical sector for ammonia and methanol while reducing CO_2 emissions (Box 9). The three main cleaner process technology options are: using CCUS to reduce fossil fuel-related emissions (assuming sufficient CO_2 transport and storage infrastructure is in place); using electrolysis-derived hydrogen (assuming a renewable electricity supply); and using biomass feedstocks (assuming a sustainable supply of bioenergy). Today all of these options are more costly than using fossil fuels without CCUS.

Box 9. Existing and planned low-carbon ammonia and methanol production

Three facilities in the United States were capturing CO_2 from the production of hydrogen for ammonia-based fertilisers in 2018. In total, these operational plants have the capacity to produce over 150 ktH_2/yr of low-carbon hydrogen and capture nearly 2 MtCO2/yr. The captured CO_2 is currently fed into pipelines and used for EOR (IEA, 2016). By 2022 four similar projects are set to be commissioned. Two of these are in the United States, one is in Canada and one is in China, and all but one plan to sell the CO_2 for EOR. EOR is likely to offer declining opportunities for use of CO_2 in the long term (as oil production declines), and is not an option in all geographies. A further, larger project in south Western Australia is planned for operation by 2025, with a portion of the captured 2.5 $MtCO_2$/yr coming from hydrogen production for ammonia fertiliser and destined for geological storage without EOR.

Since late 2018 Yara, the world's largest ammonia producer, has been using by-product hydrogen from a steam cracker to reduce its consumption of natural gas (and a reported 10 $ktCO_2$/yr of emissions) in an existing ammonia plant in the Netherlands (Brown, 2019). In collaboration with the energy company ENGIE, Yara is now assessing the feasibility of integrating electrolysis-based hydrogen into its operations in Australia (ENGIE, 2019). Feasibility studies are also being undertaken for electrolytic hydrogen projects in Chile (German Government, 2018) and Morocco (Fraunhofer IMWS, 2018). Work is also being undertaken in Iowa in the United States to produce ammonia using hydrogen from solar-powered electrolysis for use as a fertiliser and a fuel (Schmuecker Pinehurst Farm LLC, 2017), and there are similar-scale research and pilot facilities in Oxford in the United Kingdom and Minnesota in the United States.

VärmlandsMetanol AB and ThyssenKrupp Industrial Solutions plan to commission the world's first commercial-scale biomass gasification demonstration plant in Sweden to produce methanol

(VärmlandsMetanol AB, 2017). The process will use similar equipment to coal-based methanol production, currently widespread in China and being investigated as a prospect for substituting natural gas consumption in India (ET Energy World, 2018). Methanol is also being produced from biogas by BioMCN in the Netherlands (BioMCN, 2019) and from municipal solid waste in Canada (Enerkem, 2019). The Carbon2Chem, Steelanol and Vulcanol projects in Europe, and a Mitsui Chemicals project in Japan, seek to make use of the CO_2 (and CO) from steel production and power generation to produce methanol, among other chemicals.

Sources: Brown (2019), "Ammonia plant revamp to decarbonize: Yara Sluiskil"; ENGIE (2019), "ENGIE and YARA take green hydrogen into the factory"; German Government (2018), "'Green' hydrogen beckons for Chilean industry"; Fraunhofer IMWS (2018), "Fraunhofer IMWS and OCP Group sign Memorandum of Understanding"; Schmuecker Pinehurst Farm LLC (2017), *Carbon Emission Free Renewable Energy*; VärmlandsMetanol AB (2017), "In short about VärmlandsMetanol Ltd"; ET Energy World (2018), "Task force to study feasibility of making methanol from coal"; BioMCN (2019), "BioMCN produces methanol and bio-methanol"; Enerkem (2019), "Enerkem enables the chemical industry to achieve sustainability by recycling carbon from garbage".

Using biomass for ammonia and methanol production looks significantly less cost-competitive than the other options (Figure 41), so the focus in the analysis in this section is on the use of natural gas with CCUS and on the use of electrolytic hydrogen.

Meeting future ammonia and methanol demand entirely from these cleaner pathways would considerably increase demand for energy inputs to the chemical sector (Figure 40). If future demand in a Paris-compatible pathway were to be met entirely with hydrogen produced from natural gas with CCUS, around 320 bcm of natural gas would be required by 2030, nearly half of which would be used as feedstock. This is around 10% of global natural gas demand today. Around 450 $MtCO_2$/yr would need to be captured, although around one-third of this could be used to produce urea. The largest carbon capture installations today are in the region of 1 $MtCO_2$/yr. Capturing 450 $MtCO_2$/yr by 2030 would require around 450 new projects of this size to be operational by this date, with a build rate of around 4 new projects per month between now and 2030.

If future demand were to be met entirely from low-carbon electrolytic hydrogen, this would require around 3 020 terawatt hours per year (TWh/yr) of additional electricity by 2030, equivalent to around 11% of today's global electricity generation. It would also require 350–450 GW of electrolyser capacity, depending on efficiency levels and capacity factors. The largest individual electrolysers currently under development are at the 100+ MW scale, meaning that 3 500–4 000 such installations would need to be constructed by 2030, or 6–7 per week between 2018 and 2030. Around 0.6 billion cubic metres per year (bcm/yr) of water would also be needed as feedstock for the electrolysers, which is around 1% of total water consumption in the energy sector today. Some 0.5 gigatonnes per year (Gt/yr) of oxygen would be produced as a by-product, which could be used in other industrial processes.

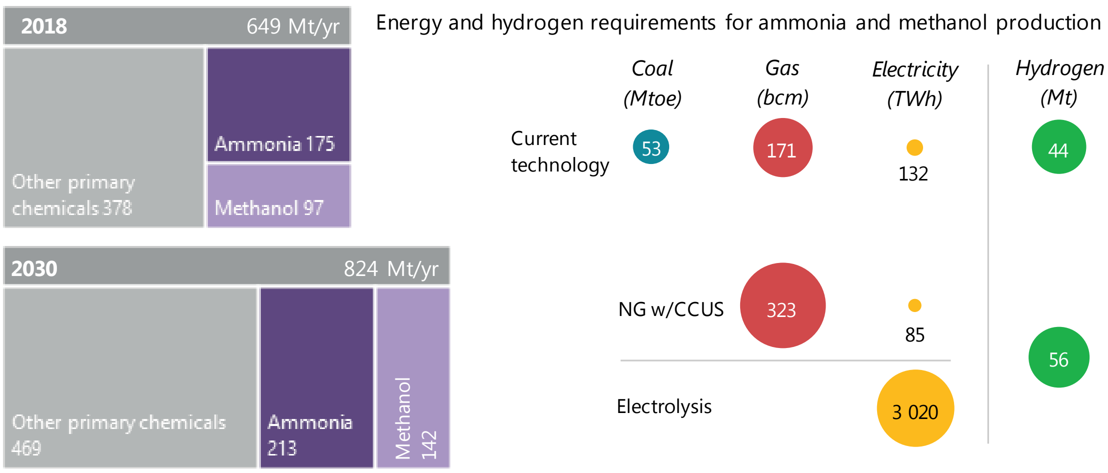
The electrolysis pathway would use some CO_2 for the manufacture of urea (CH_4N_2O) and methanol (CH_3OH).[30] To avoid fossil fuel use in methanol synthesis altogether in 2030, 200 $MtCO_2$/yr (or the equivalent amount of carbon monoxide, if available) would need to be

[30] In the case of urea, this embedding of CO_2 is only temporary, as it is re-released as the urea decomposes during application in the agricultural sector. For methanol the sequestering of the CO_2 could theoretically be permanent, although many methanol applications today involve the carbon in methanol (and its chemical derivatives) being oxidised back to CO_2 and released.

sourced and captured from biogenic (e.g. biomass gasification) or atmospheric (e.g. direct air capture) sources. A further 170 $MtCO_2$/yr or equivalent would be required for urea.

In the absence of an economic source of biogenic or atmospheric CO_2, it would still be beneficial to capture and utilise CO_2 streams from unabated stationary point sources of CO_2 (e.g. steel and cement production). These are likely to remain much cheaper in the short to medium term. However, the total emissions avoided would be much lower unless that CO_2 would otherwise unavoidably have been emitted (Chapter 2). Geographically matching locations of low-cost renewable electricity, water availability and persistent CO_2 sources that are not prohibitively expensive presents a significant challenge.

Figure 40. The implications of cleaner process routes for methanol and ammonia production



Notes: NG = natural gas; w/ = with. Best practice energy performance used for 2030 natural gas estimates. 2030 electrolyser efficiency = 69% on an LHV basis. Demand figures for 2030 are consistent with those of the Clean Technology Scenario (IEA, 2018a), a scenario in which the goals of the Paris Agreement are achieved, including the implementation of materials efficiency strategies. Bubbles denoting energy and hydrogen requirements are sized on an LHV energy content basis. The hydrogen and energy quantities are equivalent, and *not* additive.

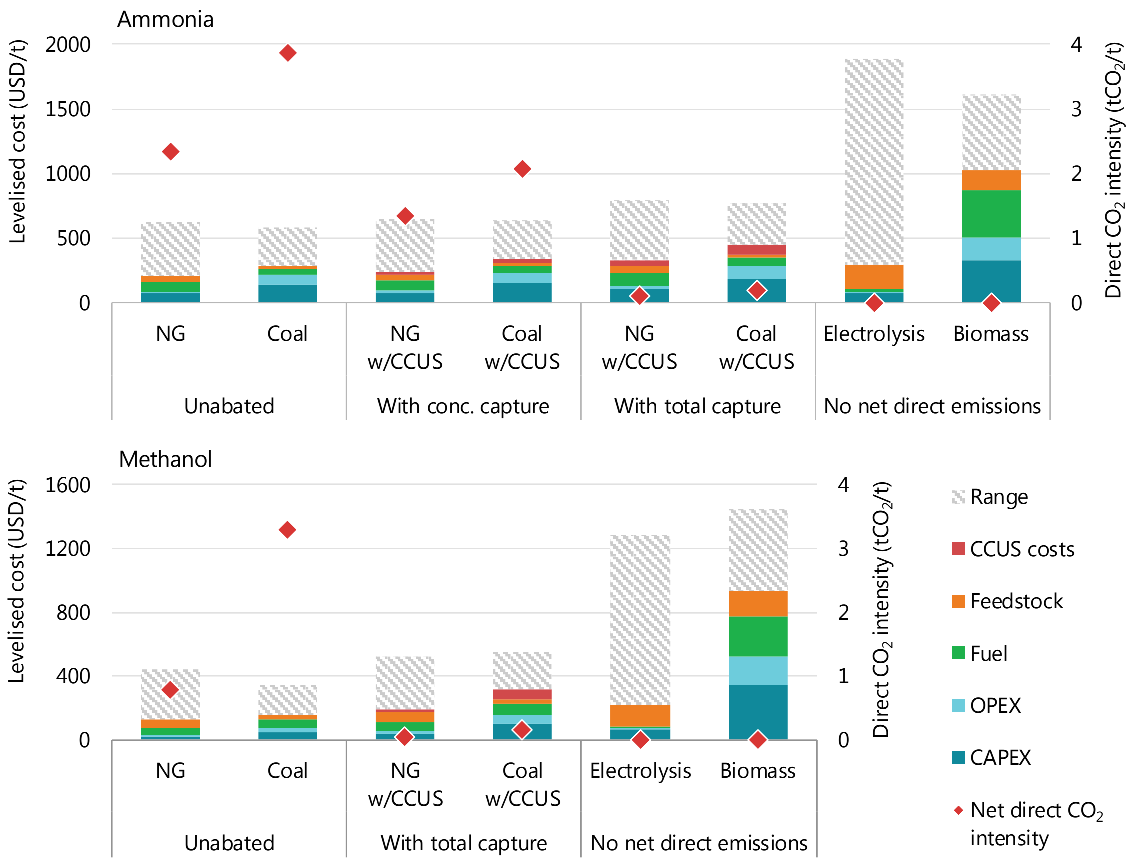
Source: IEA 2019. All rights reserved.

Satisfying the entire demand for ammonia and methanol through low-carbon production would require 323 bcm of natural gas paired with CCUS, or 3 020 TWh/yr of renewable electricity by 2030.

Cost competitiveness of cleaner pathways

Cleaner ways of producing ammonia and methanol have higher costs than those that are commercially available today. Production costs vary widely, however, between regions, depending on the costs of in each region of natural gas, coal, biomass and electricity (Figure 41).

Figure 41. Costs and CO_2 intensities for greenfield ammonia and methanol production in 2018



Notes: conc. = concentrated; t = tonne. *CCUS costs* includes the costs of capturing, transporting and storing CO_2. *Range* refers to the range of total levelised costs across regions, with the lower end of the range (the best case for each technology) disaggregated for each technology. It is assumed that the electrolysis route is supplied with 100% renewable electricity, and the source of the biomass in the relevant routes is sustainably procured with no net CO_2 emissions. *With total capture* describes an arrangement where both process- and energy-related emissions are captured, whereas *With conc. capture* describes an arrangement where only process emissions are captured. More information on the assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

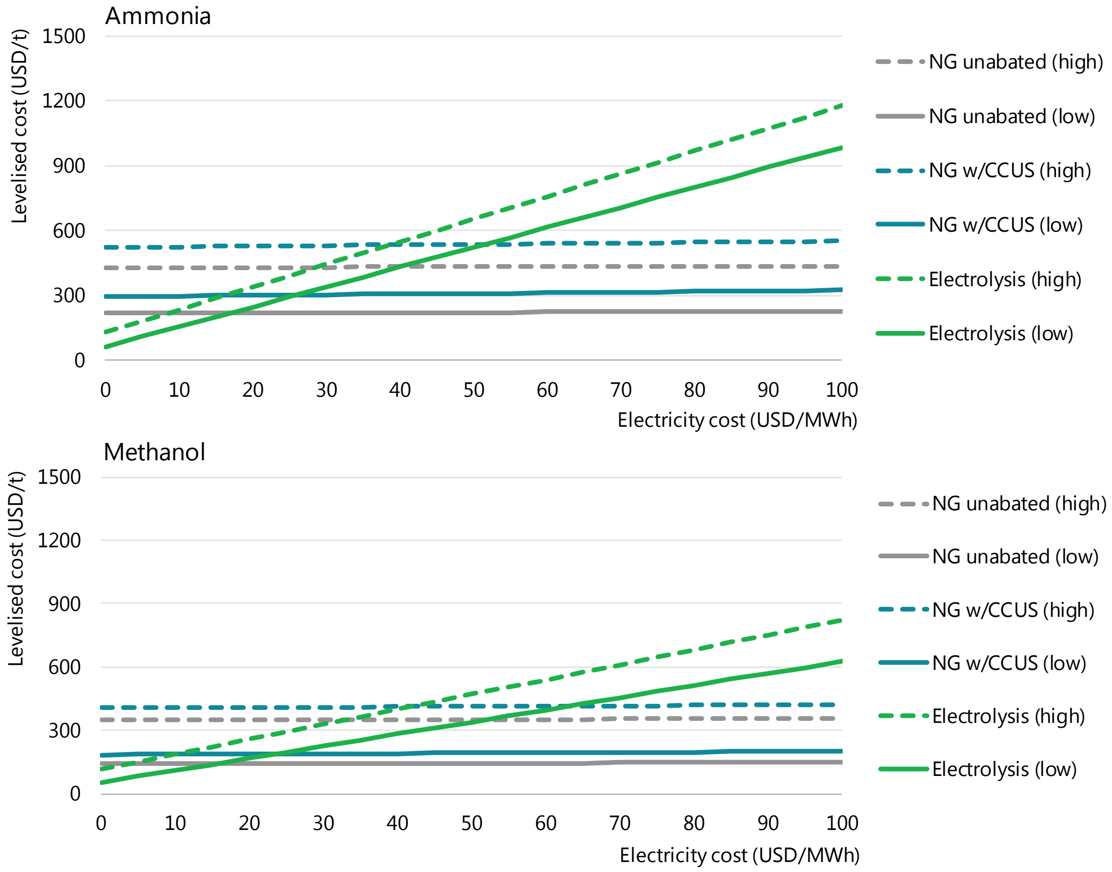
Low-carbon ammonia and methanol production today is significantly more expensive than production using unabated fossil fuels.

In locations with the lowest cost renewable electricity (for example in Chile, Morocco and China), electrolytic hydrogen would be close to being competitive in cost terms with natural gas and coal for ammonia and methanol production, even if they did not use CCUS. While these locations are some way from today's centres of demand for these products, they might attract future inward investment, although additional costs for buffer storage and other strategies for coping with the intermittency of variable renewables could raise the costs above those shown in Figure 41. Transporting renewable electricity to the main demand centres is another option, but would also involve additional costs (Box 4 in Chapter 2).

Much of the technology and equipment required for the cleaner pathways in the chemical sector is already in widespread use across the industry, including the pumps, compressors and separation units required for CO_2 capture. Electrolysers have been constructed at scales above 100 MW in the past, and significant efforts are being made to bring down their costs further

(Chapter 2). The key variables affecting the economics of production via electrolysis and natural gas with CCUS are natural gas and electricity prices (Figure 42).

Figure 42. Variation of ammonia and methanol production costs with fuel price in the long-term



Notes: The *levelised cost* includes the cost of CAPEX on core process equipment, fixed OPEX, fuel and feedstock costs, and the cost of capturing, transporting and storing CO_2. Best practice energy performance is assumed for natural gas-based routes. Electrolyser CAPEX range = USD 455–894/kW_e. Electrolyser efficiency range = 64–74% on an LHV basis. More information on the assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

At low electricity prices, electrolysis is the best option for producing low-carbon ammonia and methanol, but natural gas with CCUS is more competitive at higher electricity prices.

Electrolysis becomes competitive with natural gas with CCUS at electricity prices in the range of USD 15–50/MWh for ammonia and in the range of USD 10–65/MWh for methanol, on the assumption of gas prices of USD 3–10/MBtu.[31] In order to compete with natural gas without CCUS at these gas prices, however, electricity prices would need to drop to USD 10–40/MWh for ammonia and USD 5–50/MWh for methanol.

While the upper end of these cost-competitive electricity price ranges show promise for alternative pathways, the economics in most regions are such that policy support is likely to be

[31] This assumes that electrolyser CAPEX declines by 50% and efficiency increases by 15%, with no corresponding improvement in the efficiency of natural gas conversion or CCUS.

required in the short to medium term if low-carbon forms of production are to take off. Policy measures could stimulate demand for low-carbon hydrogen in the chemical sector and thus stimulate investment in a cleaner supply of hydrogen. These measures could include the use of certificates, public procurement or portfolio standards to create market value for chemicals produced via low-carbon process routes. In the case of methanol produced as a fuel or fuel additive, this could include the use of fuel specifications or fuel standards (Box 8). Governments could also use standards to support ammonia produced with lower CO_2 intensity. In the near term, initial projects that take on value chain and market risks to invest in CCUS or electrolysis hydrogen for chemical production are likely to need some direct government support. The support should be aimed at managing these risks and extending the benefits of cost sharing to other facilities in industrial clusters.

Hydrogen in iron and steel production

DRI is a method for producing steel from iron ore. This process constitutes the fourth-largest single source of hydrogen demand today (4 MtH_2/yr, or around 3% of total hydrogen used in both pure and mixed forms), after oil refining, ammonia and methanol. Based on current trends, global steel demand is set to increase by around 6% by 2030, with demand for infrastructure and a growing population in developing regions compensating for declines elsewhere.

Like the chemical sector, the iron and steel sector produces a large quantity of hydrogen mixed with other gases as a by-product (e.g. coke oven gas), some of which is consumed within the sector and some of which is distributed for use elsewhere. Virtually all of this hydrogen is generated from coal and other fossil fuels. To reduce emissions, efforts are underway to test steel production using hydrogen as the key reduction agent (as opposed to carbon monoxide derived from fossil fuels), with the first commercial-scale designs expected in the 2030s. In the meantime, low-carbon hydrogen could be blended into existing processes that are currently based on natural gas and coal to lower their overall CO_2 intensity.

How does the iron and steel sector use hydrogen today?

More than three-quarters of global steel demand today is met using primary production methods that convert iron ore to steel, as opposed to the secondary production route, which utilises limited supplies of recycled scrap steel (Figure 43).[32] The two main primary production routes already involve some production and consumption of hydrogen.

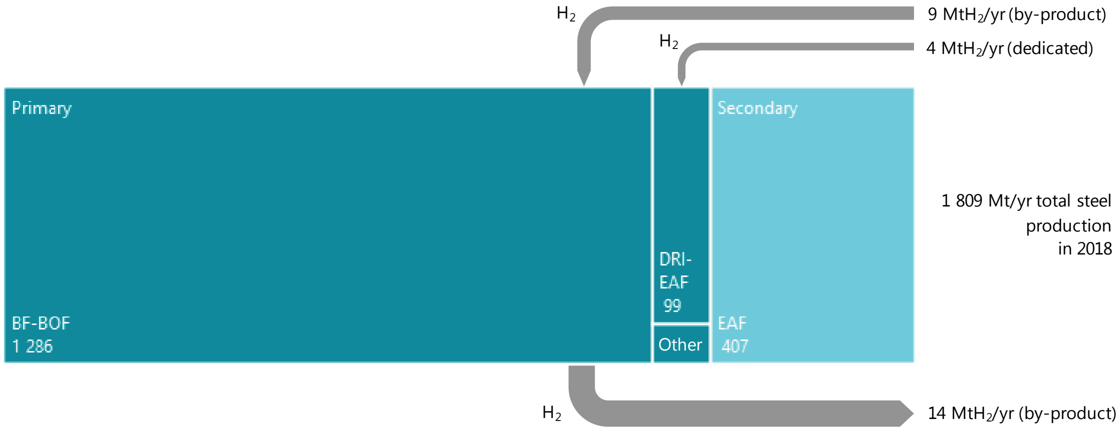
The **blast furnace-basic oxygen furnace** (BF-BOF) route accounts for about 90% of primary steel production globally. It produces hydrogen as a by-product of coal use. This hydrogen, contained in so-called "works-arising gases" (WAG), is produced in a mixture with other gases such as carbon monoxide.[33] WAG is used for various purposes on site, but also transferred for use in other sectors including power generation and, in China, methanol production. The portion utilised within the iron and steel sector is estimated at 9 MtH_2/yr today, or around 20% of the global use of hydrogen in mixed forms (i.e. not as pure hydrogen).

[32] The remaining demand is met by re-melting steel scrap in an electric arc furnace (EAF). Besides the BF-BOF and DRI-EAF routes, there are other routes currently used for primary steel production, such as the smelt reduction process (in combination with a BOF) and the outdated open hearth furnace route. Together these other routes account for around 1% of primary production.

[33] Coke oven gas typically contains in the range of 39% to 65% hydrogen by volume, whereas blast furnace gas contains in the range of 1% to 5% (European Commission, 2000). BOF gas is another component of WAG, containing 2% to 10% hydrogen by volume.

The **direct reduction of iron-electric arc furnace** (DRI-EAF) route accounts for 7% of primary steel production globally. It uses a mixture of hydrogen and carbon monoxide as a reducing agent. The hydrogen is produced in dedicated facilities, not as a by-product. Around three-quarters of it is produced using natural gas (reforming) and the rest using coal (gasification). It accounts for around 4 MtH_2/yr in 2018, or 10% of the use of hydrogen consumed in mixed forms globally.[34]

Figure 43. Hydrogen consumption and production in the iron and steel sector today



Notes: Steel quantities estimated based on recent data from the sources below and stated in Mt/yr. Associated hydrogen consumption and production from IEA estimates based on energy statistics and a specific hydrogen requirement for the DRI-EAF route of 43 kgH_2/t of DRI. The 4 MtH_2/yr consumed in the DRI-EAF route are used as a reduction agent, whereas the 9 MtH_2/yr consumed in the BF-BOF route (and associated processes on integrated sites) are mostly combusted.

Source: World Steel Association (2018), *Steel Statistical Yearbook 2018*. World Steel Association (2019), "World Crude Steel Production - Summary".

Today the iron and steel sector accounts for 4 MtH_2/yr of dedicated hydrogen production. Of the 14 MtH_2/yr it produces as a by-product in hydrogen-containing gases, it consumes roughly 9 MtH_2/yr, with the remainder exported for use in other sectors.

Potential for future hydrogen demand for iron and steel

Without policy intervention, demand for dedicated hydrogen production in steel-making is expected to grow from the current level of 4 MtH_2/yr roughly in line with the gas-based DRI-EAF route (Figure 44).[35] While the gas-based DRI-EAF can be more energy-intensive than the BF-BOF route, it uses simpler and slightly less capital-intensive equipment.[36] It tends to be deployed in regions with low natural gas prices (e.g. the Middle East) or low coal prices (e.g. India).

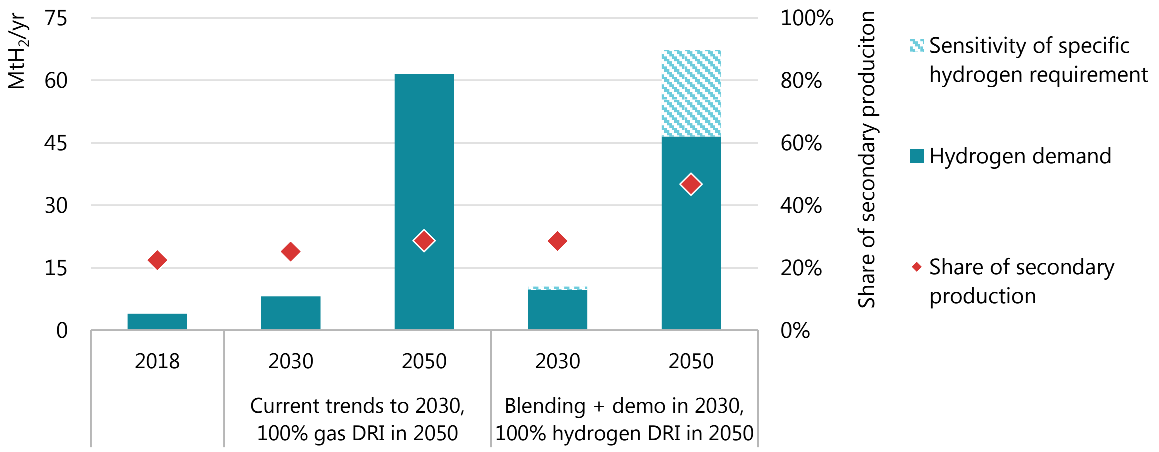
[34] Hydrogen requirements for all DRI-EAF processes considered in this publication are estimates based on personal communication with representatives from Voestalpine and other iron and steel sector experts.

[35] The future use of the hydrogen contained in by-product WAG will continue to be closely integrated with BF-BOF operation. As such it is not a use of hydrogen that could provide a source of demand for alternative hydrogen supplies, such as electrolytic hydrogen or fossil fuels with CCUS.

[36] There are other important differences between these routes. In the BF-BOF route, raw material preparation is typically done on site (e.g. agglomeration, lime production), and the process is more flexible in the grades of ore it can accept. The granulated slag produced from the BF-BOF route tends to be of greater utility as a by-product than that produced in the DRI-EAF route. Both routes tend to use some scrap alongside iron ore, but the DRI-EAF tends to use more than the BF-BOF. The energy intensity comparison between the two routes is highly sensitive to site-specific conditions, such as the extent of process integration.

The two main factors to influence future dedicated hydrogen demand for steel production are: the share of the DRI-EAF route in primary steel making, and the split between primary and secondary steel production in overall output. Considering the dynamics of steel stocks in the built environment, on current trends the share of scrap-based production in total steel production is projected to grow from around 23% today to 25% in 2030. In this case, the commercial gas-based DRI-EAF route could supply 14% of primary steel demand. This would require 8 MtH_2/yr as a reducing agent (second column of Figure 44), doubling the use of hydrogen for DRI-EAF production from today's levels. In the same case, if the share of secondary steel production continued to rise (to 29% by 2050) and the gas-based DRI-EAF route was used to satisfy 100% of primary steel demand, hydrogen demand in the sector could theoretically reach 62 MtH_2/yr (third column of Figure 12). The two right-hand columns in Figure 12 are described in the next section.

Figure 44. Theoretical potential for dedicated hydrogen demand for primary steel production



Notes: The *100% gas-based DRI* case is one in which the gas-based DRI route grows in line with current trends until 2030, with the 2050 figure showing the theoretical potential if all primary production took place via gas-based DRI. The *Blending + demo in 2030, 100% hydrogen DRI in 2050* case is one in which the HYBRIT concept is demonstrated at scale (1.5 Mt/yr) by 2030, and 30% of the feed to the remaining natural gas-based DRI-EAF capacity is substituted with an external hydrogen source. By 2050, the HYBRIT concept accounts for all primary production in this case. In the former case, the share of primary production and overall steel production figures are from a context in which current trends are projected, whereas the latter is one in which action is taken to reach the goals of the Paris Agreement (greater deployment of the secondary route and uptake of materials efficiency strategies). Specific hydrogen requirement assumptions: gas-based DRI-EAF = 43 kgH_2/t of DRI; gas-based DRI-EAF with blending = 51-55 kgH_2/t of DRI, 23 kg of which could be supplied externally; 100% hydrogen-based DRI-EAF = 47–68 kgH_2/t of DRI. 95% DRI charge to the EAF is assumed in all cases. Current DRI-EAF facilities often operate with a higher share of scrap, as this lowers costs.

Source: IEA 2019. All rights reserved.

By 2030 the hydrogen requirement for the DRI-EAF route could more than double. By 2050 the use of this method for all primary production could lead to a 15-fold increase in hydrogen demand.

Using hydrogen to meet growing steel demand while reducing CO_2 emissions

On average, producing one tonne of crude steel currently results in around 1.4 tonnes of direct CO_2 emissions.[37] Several cleaner pathways are under development that would significantly reduce CO_2 emissions for primary iron and steel production (Box 10). These can be divided into two categories:

- "CO_2 avoidance" pathways seek to avoid most of the CO_2 emissions entirely by adopting low-carbon sources of energy and reduction agents, usually using hydrogen.
- "CO_2 management" pathways aim to recover and manage the CO_2 associated with traditional fossil fuel-based routes, usually via the direct application of CCUS.

Various projects are underway around the world to develop these processes towards commercialisation. These processes are generally at an earlier stage of development than those in the chemical sector described earlier in this Chapter.

Box 10. Projects for low-emissions steel production

CO_2 avoidance pathways

HYBRIT. In Sweden SSAB (a steel producer), LKAB (an iron ore pellet manufacturer) and Vattenfall (a power company) formed the HYBRIT joint venture to explore the feasibility of hydrogen-based steelmaking, using a modified DRI-EAF process design (HYBRIT, 2019). Currently at pilot phase, the first commercial plant is expected in 2036. Of the SEK 1.4 billion (USD 147 m) estimated cost of the pilot plant, the Swedish Energy Agency will provide SEK 528 m (USD 56 m), with the joint venture partners contributing the rest.

SALCOS. Like the HYBRIT project, this collaboration between Salzgitter AG and the Fraunhofer Institute aims to partially implement hydrogen-based reduction of iron ore using the DRI-EAF route (SALCOS, 2019). While HYBRIT is aiming at virtually 100% hydrogen reduction from the outset, SALCOS will utilise a natural gas-fed process design and gradually increase the proportion of hydrogen.

GrInHy and **H2FUTURE.** These initiatives, both funded by the European Union's Fuel Cell and Hydrogen Joint Undertaking, aim to scale up emerging electrolyser designs to ensure that variable sources of renewable electricity can be utilised effectively in steel production and other industrial operations. The H2FUTURE project, co-ordinated by the Austrian utility VERBUND, is employing a 6 MW proton exchange membrane design (H2FUTURE, 2019), while GrInHy comprises a new reversible solid oxide cell unit (GrInHy, 2019). These projects started in 2016/17 and will conclude in the early 2020s.

Σiderwin and **Boston Metal.** Σiderwin is a research project initially funded by the European Union and now being taken forward by ArcelorMittal to pilot stage. It employs electrowinning

[37] This does not account for emissions from captive utilities or subsequent uses of WAG, nor indirect emissions associated with centralised power generation. These, and several other factors, can substantially influence the emissions intensity.

to produce steel (SIDERWIN, 2019). Boston Metal is a start-up venture that has recently attracted USD 20 million of investment to continue developing its molten oxide electrolysis process for producing a variety of metals (Boston Metal, 2019). Both of these processes utilise electricity directly for reduction, avoiding the need to produce hydrogen.

Ironmaking with ammonia. In Japan researchers have demonstrated the reduction of haematite (a constituent of iron ore) with ammonia at laboratory scale (Hosokai et al., 2011). If it can be demonstrated at commercial scale, this route could facilitate steel production in areas remote from those in which hydrogen (and ammonia) can be produced cheaply via low-carbon pathways.

CO_2 management pathways

HIsarna. Developed during the Ultra-Low Carbon Dioxide Steelmaking (ULCOS) research project funded by the European Union and several large steel producers, HIsarna is a demonstration-phase process for producing steel with significant potential for emissions reductions, especially if equipped with CCUS (HIsarna, 2019). The technology employs an upgraded smelt reduction process that processes iron ore in a single step, negating the need for coke ovens and agglomeration processes. Greenfield commercial plants could be available within 10 years of the completion of the current demonstration project.

DRI with CCUS. Al Reyadah, a wholly-owned subsidiary of Abu Dhabi National Oil Company, is capturing CO_2 from a commercial-scale DRI-EAF plant operated by Emirates Steel (Al Reyadah, 2017). This post-combustion capture approach involves a chemical separation process that is more energy-intensive than that employed in the HIsarna process design, but benefits from the fact that the technology can be applied to existing equipment.

Chemicals from WAG. Several large pilot projects utilise the H_2, CO and CO_2 in WAG for various purposes. The climate benefit of these initiatives depends on the counterfactual considered, were they not to be used. The projects offer a variety of avenues to utilise a vast stock of existing steelmaking assets. Key examples include the public-private Carbon2Chem and Steelanol projects in Europe.

COURSE 50. This Japanese Iron and Steel Federation initiative seeks to raise the proportion of hydrogen used as a reduction agent in the BF-BOF route and to capture CO_2 streams from blast furnace gas, with a full-scale demonstration planned in the 2030s (COURSE 50, 2019). The hydrogen is sourced from enriched and treated WAG streams. Together these modifications could lead to a 30% reduction in CO_2 emissions per unit of steel produced.

Sources: HYBRIT (2019), "HYBRIT – towards fossil-free steel"; SALCOS (2019), "Project overview"; H2FUTURE (2019), "Production of green hydrogen"; GrInHy (2019), "Project overview"; SIDERWIN (2019), "Development of new methodologies for industrial CO_2-free steel production by electrowinning"; Boston Metal (2019), "We transform dirt to metal very efficiently"; Hosokai et al. (2011), "Ironmaking with ammonia at low temperature", *Environmental Science & Technology*; HIsarna (2019), "HIsarna: Game changer in the steel industry"; COURSE 50 (2019), "CO_2 ultimate reduction in steelmaking process by innovative technology for cool earth 50".

If, instead of following current trends, an alternative pathway were to be followed that aligns the future development of the energy sector with the goals of the Paris Agreement, the outlook for hydrogen demand and production in the sector could be very different. In such a pathway, the share of scrap recycling in total steel production is projected to grow more rapidly, from 23%

today to 29% in 2030 and 47% in 2050, limited only by the availability of steel scrap. Our analysis suggests a slightly larger share of the gas-based DRI-EAF in primary steel production by 2030 (16%) in this case, and that progress on materials efficiency strategies would also be accelerated, leading to a reduction in the overall level of output.

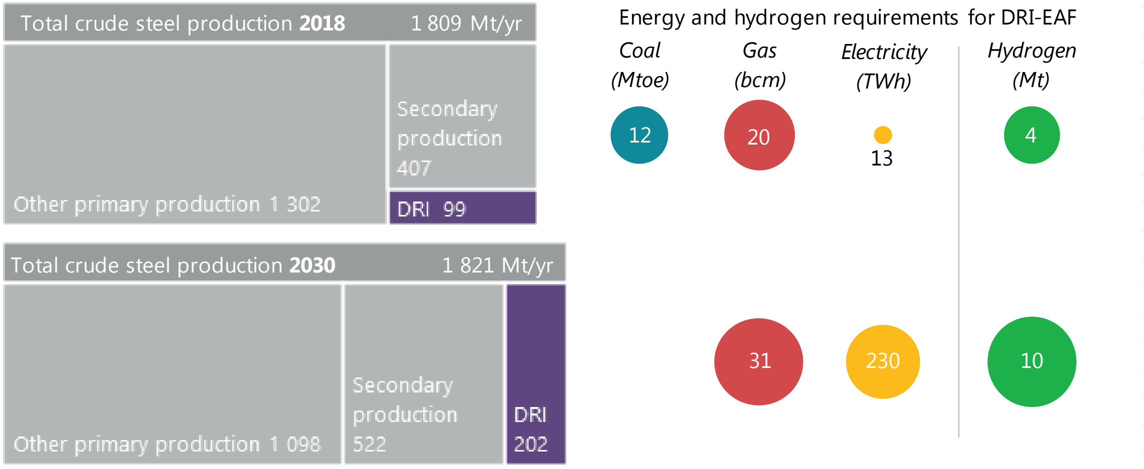
Two parallel technological developments relating to DRI-EAF are also assumed to take place in this case. First, 30% of the natural gas consumed in DRI-EAF production would be replaced by 2030 by externally sourced pure hydrogen from electrolysis, which could be done without major equipment changes (Chevrier, 2018). Second, progress on developing the HYBRIT concept (Box 10) would be sufficient to demonstrate the first commercial-scale 100% hydrogen-based DRI-EAF plant by 2030, supplying 1.5 Mt/yr of crude steel, or 0.1% of total steel demand.

If these ambitious developments were to take place, hydrogen demand for iron and steel production would be 9–11 MtH_2/yr by 2030 (the fourth column of Figure 44), similar to the level of 8 MtH_2/yr expected on the basis of current trends. However, only around 4.5 MtH_2/yr would be sourced from renewable electricity, with the remainder coming from natural gas. By comparison, under current trends all of the additional hydrogen demand would be met by natural gas without CCUS. This would require 230 TWh/yr of electricity, approximately equivalent to the total electricity consumption of Turkey today (Figure 45). Natural gas would nonetheless still play an important role in supplying the remaining hydrogen in 2030, resulting in 31 bcm/yr of natural gas demand, which is approximately equal to the natural gas consumption of Spain today. Coal-based DRI-EAF production would disappear by 2030 in this scenario, eliminating 12 Mtoe/yr, roughly the annual coal consumption of Mexico today.

In the long term a Paris-compatible pathway would seek to drastically reduce CO_2 emissions from primary steel production.[38] Using the 100% hydrogen DRI-EAF route for all primary steel production would largely eliminate CO_2 emissions, provided the electricity was sourced from renewables. As Figure 12 shows, this would require 47–67 MtH_2/yr (the fifth column of Figure 44). More than 2 500 TWh/yr of electricity would be needed to produce this much hydrogen, or roughly the combined electricity consumption of India, Japan and Korea today (Figure 45). A substantial but manageable amount of water would also be required as feedstock for electrolysers: around 0.6 bcm/yr, which is about 1% of total water consumption in the energy sector today. Some 500 Mt/yr of oxygen would be produced as a by-product; this could be put to use elsewhere in industry.

[38] "CO_2 emissions free" is not the same as being "carbon free". Some carbon will continue to be required in the process of steelmaking, as it is a key chemical constituent of the final material.

Figure 45. Energy implications of fulfilling hydrogen demand via the DRI-EAF route



Notes: Only the energy and hydrogen requirements for the commercial coal/gas-based and 100% hydrogen-based DRI-EAF routes are included. Demand figures are consistent with a scenario in which the goals of the Paris Agreement are achieved, including the implementation of materials efficiency strategies and maximum deployment of the secondary production route. Average hydrogen requirements for both the gas- and 100% hydrogen-based DRI-EAF routes are assumed in calculating the hydrogen requirements and energy inputs. Bubbles denoting energy and hydrogen requirements are sized on an LHV energy content basis. The hydrogen and energy quantities are equivalent, and *not* additive. 95% DRI charge to the EAF is assumed in all cases. Current DRI-EAF facilities often operate with a higher share of scrap, as this lowers costs. More information on the assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

While the role of hydrogen could expand dramatically in the medium to long term, gas would continue to play an important role even after 2030 while the shift took place.

Cost competitiveness of cleaner pathways

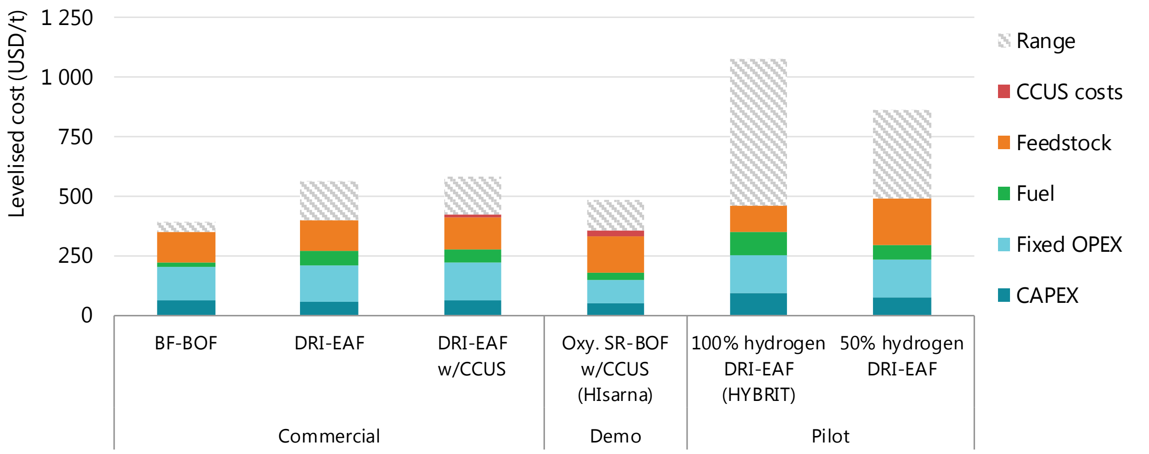
In the absence of sufficiently high CO_2 prices to trigger a switch to low-carbon hydrogen, replacing unabated natural gas with renewable hydrogen in the DRI-EAF route would widen the difference in cost between the commercial DRI-EAF and BF-BOF routes (Figure 46). Energy and other raw material input costs represent upwards of about 45% of production costs for the DRI-EAF routes, so small price differences can make a big difference to cost competitiveness. Whereas the range of gas prices today makes the commercial DRI-EAF route competitive with the BF-BOF route in specific instances, the hydrogen-based DRI-EAF route, based on current estimates of key technology parameters, would only be competitive in those places with the lowest electricity prices. It would also be significantly more expensive than its natural gas-based counterpart (15–90% more), even if natural gas production involved CCUS (10–85% more).

Among the other low-emissions pathways for steel production currently being explored, the "oxygen-rich smelt reduction BOF with CCUS" (HIsarna) route appears to have the lowest overall production costs in most regions in the current energy price context. According to the limited techno-economic information currently available in the public domain, it is less capital-intensive even than today's commercial BF-BOF route, and could reduce direct CO_2 emissions by around 80–90%. In most regions, the family of "CO_2 management" pathways tends to be at a more advanced stage of development today. In the context of a long-term Paris-compatible pathway, however, the HIsarna design would have to be deployed in conjunction with a widespread CO_2 transport and geological CO_2 storage infrastructure.

Another key consideration, which is not explored in Figure 46, is the stock of existing capacity. Despite recent efforts to decommission underutilised assets, the steel industry still suffers from overcapacity, and the market remained fragile in 2018 (OECD, 2019). Furthermore, the BF-BOF route accounts for around 90% of existing primary capacity, an asset class in which steel producers are generally not anticipating substantial greenfield investments in the coming years. With many facilities utilising this technology having been constructed in the past 10–20 years, it is going to be difficult for new alternative production routes to outcompete them without policy intervention. These dynamics underpin the development of CO_2 management pathways (Box 10), which generally seek to reduce emissions while making use of existing integrated steel facilities. HIsarna is an exception to this as it requires greenfield investment.

To compete in the long term with its natural gas-based counterpart equipped with CCUS, the 100% hydrogen-based pathway currently looks likely to need low-carbon electricity prices in the range of USD 5–35/MWh (Figure 47). This translates into hydrogen costs of USD 0.7–2.0/kgH_2, assuming electrolysers with high efficiencies and low CAPEX requirements. As discussed in Chapter 2, these costs may be realistic in certain regions when using dedicated low-cost renewable resources, but are challenging to achieve elsewhere. Moreover, regions with low-cost renewables resources may involve extra costs if they are not endowed with sufficient reserves of iron ore and other materials, and if they are located far from centres of demand.

Figure 46. Estimated costs of steel for selected greenfield production routes in 2018



Notes: Oxy. SR-BOF = oxygen-rich smelt reduction. CCUS costs includes the costs of capturing, transporting and storing CO2. Range refers to the range of total levelised costs across regions, with the lower end of the range disaggregated for each technology. An availability factor of 95% is applied to all equipment and an 8% discount rate is used throughout. It is assumed that the electrolysis route is supplied with 100% renewable electricity. Natural gas-based and 100% hydrogen-based DRI-EAF considers 95% DRI charge to the EAF. More information on the assumptions is available at www.iea.org/hydrogen2019.

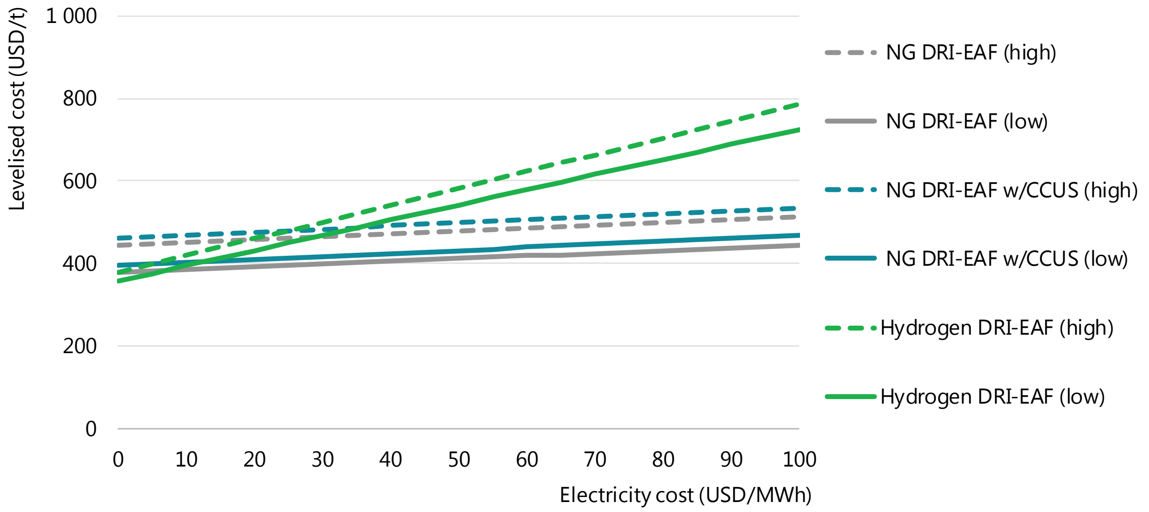
Source: IEA 2019. All rights reserved.

The hydrogen-based DRI-EAF route is between 10% and 90% more costly than its natural gas-based counterpart, and is highly sensitive to the cost of electricity.

From a policy perspective, there are two key areas where support is needed to bolster the sustainable adoption of hydrogen as a reduction agent in the iron and steel sector. First, support is needed for demonstration projects that seek to scale up the 100% hydrogen-based DRI-EAF process; this could, for example, take the form of access to low-cost financing for increasing scales of demonstration, and funding to supporting the specific aspects of research and development (R&D) required to accelerate development.

Second, differentiated markets must be established to support the increased costs faced by steel producers introducing renewable hydrogen into their operations. This should extend to hydrogen blending with natural gas in the short term, as this can help scale up electrolysis and dedicated renewables installations, but should move towards sole support for the 100% hydrogen-based route once it has reached commercial-scale demonstration. For example, public procurement contracts could be modified to require contractors for a public building or infrastructure project to use a gradually rising share of "green steel". This could help kick-start the demand for an initially more costly product. Steel producers will have limited capacity to absorb these costs themselves, owing to the relatively slim margins on this widely traded bulk commodity. Beyond this, there are several market sectors and end-use products where consumers, especially in industrialised economies, could absorb slightly higher costs, such as a 1% increase in the price of a car (ETC, 2018).

Figure 47. Comparison of cleaner routes for steel production in the long term



Notes: The *levelised cost* includes the cost of CAPEX on core process equipment, fixed OPEX, fuel and feedstock costs, and the cost of capturing, transporting and storing CO_2. Best practice energy performance is assumed for natural gas-based routes. Electrolyser CAPEX range = USD 455–894/kW_e. Electrolyser efficiency range = 64–74% on an LHV basis. 95% DRI charge to the EAF is assumed in all cases. More information on the assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

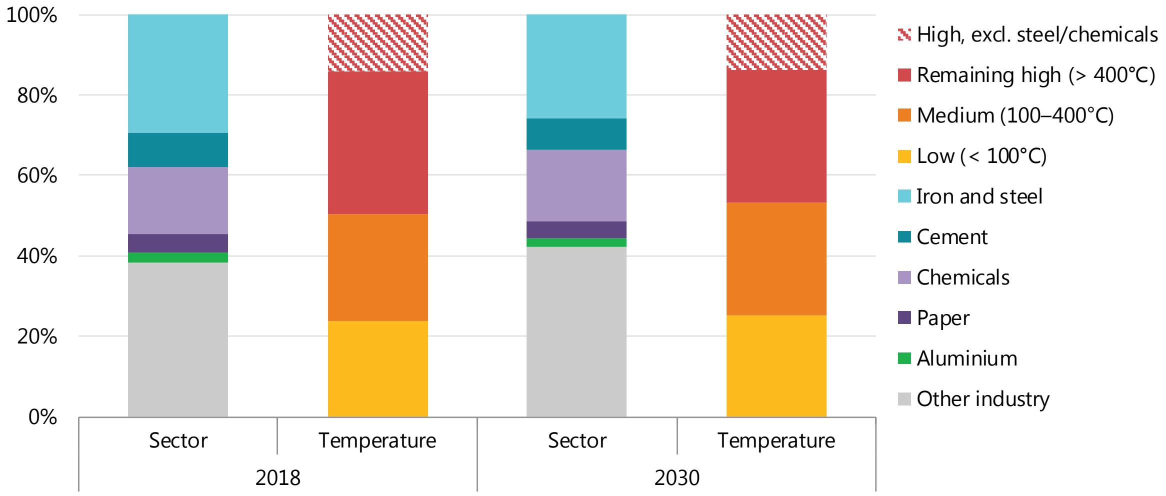
Electrolytic hydrogen-based routes start to compete with their natural gas-based counterpart equipped with CCUS at electricity prices of USD 5–35/MWh.

Hydrogen for high-temperature heat

Industrial high-temperature heat is a potential source of hydrogen demand growth in the future, but virtually no dedicated hydrogen is produced for this application today. Industry uses heat for a variety of different purposes, including melting, gasifying, drying, and mobilising a wide array of chemical reactions. Heat can be used both directly, for example in a furnace, or indirectly, for example by first raising steam and then transferring it for heating needs. There are three main temperature ranges for industrial heat: low temperature (< 100°C), medium temperature (100–400°C) and high temperature (> 400°C).

Global demand for high-temperature heat in industry was around 1 280 Mtoe/yr in 2018, of which just 370 Mtoe/yr was outside the chemical and iron and steel sectors covered in the previous sections (Figure 48). More than half of this remainder was consumed in cement manufacture (IEA and CSI, 2018). This level of demand is set to rise gradually on current trends to just over 400 Mtoe/yr in 2030. This demand trajectory would not change significantly even if strong climate change mitigation measures were pursued, although some small differences would arise from increases in energy and materials efficiency.

Figure 48. Demand for heat in industry under current trends



Source: IEA 2019. All rights reserved.

Nearly 30% of high-temperature heat in industry is consumed outside chemical and iron and steel sectors, with this share remaining relatively constant on current trends.

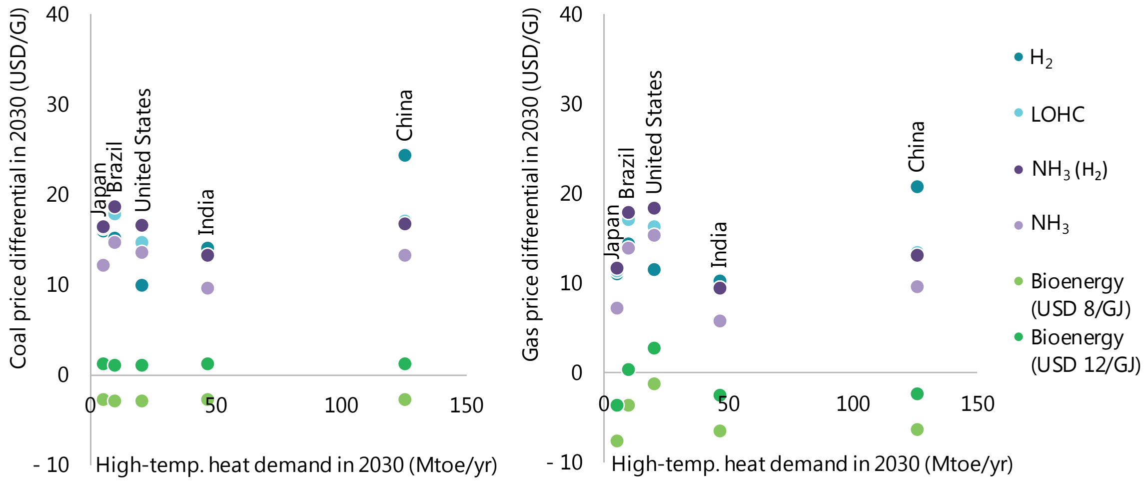
Fossil fuels are the primary source of high-temperature heat today (around 65% from coal, 20% natural gas and 10% from oil), although small amounts of biomass and waste are used in certain sectors. Electricity is also used extensively to generate high-temperature heat in specific applications, either directly (e.g. electric arc and induction furnaces in the steel industry) or indirectly (e.g. to drive electro-chemical reactions in aluminium smelting). Resistance heaters are used in the production of carbon fibre, reaching temperatures of 1 800°C, and there are ways to utilise electromagnetic heating technologies (e.g. microwave and infrared) to achieve similar temperatures for other specific heating applications (Beyond Zero Emissions, 2018). However, several large-scale processes, such as steam crackers and cement kilns, remain challenging to electrify although demonstration and feasibility studies are being conducted in both of these areas (BASF, 2019; Cementa, 2019).

Economics of hydrogen-based high-temperature heat

Excluding the chemical and iron and steel sectors, industrial high-temperature heat is responsible for approximately 1.1 $GtCO_2$/yr of direct emissions today, or around 3% of global energy-sector CO_2 emissions. Combustion of sustainable bioenergy or hydrogen (or direct use of hydrogen-based fuels such as ammonia) offer ways of reducing emissions that are proven at scale. However, negligible quantities of hydrogen are currently used for this purpose today.[39]

Despite having the potential to eliminate emissions from high-temperature heat for industry, hydrogen remains an expensive alternative to fossil fuels in the context of a low-carbon pathway for the energy system, even when CO_2 prices reach USD 100/tCO_2 (Figure 49). Bioenergy tends to be more cost-competitive in this context, assuming a bioenergy price range of USD 8–12/GJ in 2030. In all regions explored in Figure 49, bioenergy is cheaper than the hydrogen-based fuels and thus shows a smaller differential relative to coal and natural gas prices.

Figure 49. Economics and future potential in the context of a USD 100/tCO_2 carbon price



Notes: LOHC = liquid organic hydrogen carrier; NH_3 (H_2) = hydrogen transported as ammonia and then converted back to hydrogen; NH_3 = ammonia transported and combusted as ammonia. High-temperature heat demand refers to non-chemical/iron and steel sector heat demand > 400°C. The regional price differentials are calculated using the cheapest source of each hydrogen-based fuel available (whether imported or domestically produced) and the domestic prices of coal and gas. More information on the assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

In key regions for high-temperature heat demand in 2030, low-carbon hydrogen-based fuels are likely to be a significantly more expensive alternative to fossil fuels than bioenergy

Bioenergy is set to become cost-competitive with natural gas as a source of high-temperature heat in 2030 in India, China and Japan, even at the higher end of the bioenergy price range explored (USD 12/GJ). This is due to relatively high natural gas prices in these regions in the context of a Paris-compatible pathway for the energy system (USD 3.8–10.6/MBtu). A CO_2 price of around USD 200/tCO_2 would be needed before the cheapest hydrogen-based fuels (at a delivered cost of USD 2.3–2.7/kgH_2) become competitive with coal and natural gas.

Hydrogen does, however, offer some advantages for decarbonising elements of this diverse segment of energy demand, despite its relatively high costs and the need for it to overcome

[39] This excludes the hydrogen portions of fuel gas that are recirculated for combustion (e.g. coke oven gas, by-product gas from steam cracking). The utilisation of these by-product gases is not relevant to the scope of this analysis, because they are not likely to represent growth areas for low-carbon hydrogen production in the future.

certain practical difficulties (Box 11). For example, 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. Hydrogen, either via pipeline or using small-scale on-site electrolysis, could form a low-carbon energy supply to these "hard-to-reach" segments of industry. Its potential role may also grow if the supply of sustainable bioenergy is limited in the future; bioenergy is also likely to be in demand in other end-use sectors such as aviation.

Box 11. General challenges facing the use of hydrogen for heat in industry

Pure hydrogen cannot simply replace coal or natural gas in many industry sectors, owing to the diversity and specific nature of the energy conversion devices (such as kilns, furnaces, boilers, reactors) that those sectors use. In the cement industry, for example, several factors would require changes to equipment and practices, adding to the total costs of conversion:

- Hydrogen has a high combustion velocity relative to carbon-containing fuels, and a non-luminous flame, which makes it difficult to monitor optically. These challenges can be partially overcome by using hydrogen/ammonia mixes, as ammonia burns at a much lower velocity and with a visible flame, also helping to reduce (nitrogen oxide) NO_x emissions (Li et al., 2014).
- Hydrogen flames achieve relatively low radiation heat transfer compared to other fuels, requiring other (carbon-free) media (such as clinker dust) to be introduced into the fuel stream (Hoenig, Hoppe and Emberger, 2007).
- Current burners may need to be redesigned to deal with any new media being introduced (for example, to cope with the abrasive properties of clinker dust).
- Hydrogen causes corrosion and brittleness when it comes into contact with some metals, requiring new coatings and other protective measures.
- Intermittent sources of hydrogen could present difficulties for high-temperature heat users operating "on-demand" processes, and potentially require costly on-site storage, although other high-temperature heat users could be remunerated for flexibility and the enabling of ancillary grid services.
- Handling and storing hydrogen on site presents additional difficulties compared with traditional fuels, due to its explosive properties. While many industrial operators are experienced at handling hazardous substances, it may be safer to store hydrogen in other forms, such as ammonia (Hoenig, Hoppe and Emberger, 2007).

Sources: Hoenig, Hoppe and Emberger (2007), "Carbon capture technology – options and potentials for the cement industry"; Li et al. (2014), "Study on using hydrogen and ammonia as fuels: Combustion characteristics and NO_x formation", *International Journal of Energy Research*.

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Chapter 5: Opportunities for hydrogen in transport, buildings and power

- **Hydrogen holds long-term promise in many sectors beyond existing industrial applications**. The transport, buildings and power sectors all have potential to use hydrogen if the costs of production and utilisation develop favourably relative to other options. The complex processes involved in developing and deploying hydrogen, however, mean that carefully crafted policy support will be critical.

- **The competitiveness of hydrogen FCEVs in transport depends on fuel cell costs and on the building and utilisation of refuelling stations.** For cars the priority is to bring down the cost of fuel cells and on-board hydrogen storage. This could make them competitive with battery electric vehicles at driving ranges of 400–500 km and make them potentially attractive for consumers that prioritise range. For trucks the priority is to reduce the delivered price of hydrogen. In early stages of deployment, building hydrogen stations that serve captive fleets on hub-and-spoke missions could help to secure high refuelling station utilisation and thus could be a way to get infrastructure construction off the ground.

- **Shipping and aviation have limited low-carbon fuel options available and represent an opportunity for hydrogen-based fuels**. Ammonia and hydrogen have the potential to address environmental targets in shipping, but their cost of production is high relative to oil-based fuels. Hydrogen-based liquid fuels provide a potentially attractive option for aviation at the expense of higher energy consumption and potentially higher costs. Policy support in the form of low-carbon targets or other approaches is critical to their prospects.

- **The largest near-term opportunity in buildings is blending hydrogen into existing natural gas networks.** In 2030 up to 4 Mt of potential hydrogen use for heating buildings could come from low-concentration blending which, if low-carbon, could help to reduce emissions. The potential is highest in multifamily and commercial buildings, particularly in dense cities, where conversion to heat pumps is more challenging than elsewhere. Longer-term prospects in heating could include the direct use of hydrogen in hydrogen boilers or fuel cells, but both of these would depend on infrastructure upgrades and on measures to address safety concerns and provide public reassurance.

- **Power generation offers many opportunities for hydrogen and hydrogen-based fuels**. In the near term ammonia could be co-fired in coal-fired power plants to reduce CO_2 emissions. Hydrogen and ammonia can be flexible generation options when used in gas turbines or fuel cells. At the low capacity factors typical of flexible power plants, hydrogen costing under USD 2.5/kg has good potential to compete. Key low-carbon competitors for such services include natural gas with CCUS and biogas. In the longer term, hydrogen can play a role in large-scale and long-term storage to balance seasonal variations.

Maximising the potential long-term promise of hydrogen depends on moving beyond the existing industrial uses of hydrogen described in Chapter 4, and on the development of a strong case for its use as a versatile fuel in various new sectors. This case rests largely on its ability to help diversify the fuel mix and, if produced from low-carbon sources, support the transition to a cleaner energy system. Numerous opportunities exist to use hydrogen outside industrial applications: practically all modes of transport could potentially be run on hydrogen or hydrogen-based fuels; building heating, cooling and electricity needs could be supplied through hydrogen; and the power sector could use hydrogen or hydrogen-rich fuels such as ammonia for the production of electricity.

Given this versatility, it may be tempting to envisage an all-encompassing low-carbon hydrogen economy in the future. However, other clean energy technology opportunities have greatly improved recently, most importantly solutions that directly use electricity, which means that the future for hydrogen may be much more one of integration into diverse and complementary energy networks. This is especially so since the use of hydrogen in certain end-use sectors faces technical and economic challenges compared with other (low-carbon) competitors. There is also an element of path dependency; for example, rail transport is already widely electrified in many countries.

This chapter explores the various possible applications of hydrogen in the transport, buildings and power sectors. It does so by reviewing the potential opportunities for hydrogen and hydrogen-based fuels, including their economic competitiveness against other alternatives.

Hydrogen as a basis for clean transport fuels

Hydrogen gas has long been heralded as a potential transport fuel. It is seen as offering a low-carbon alternative to refined oil products and natural gas, and complementing other alternatives like electricity and advanced biofuels. Hydrogen fuel cell electric vehicles (FCEVs) would reduce local air pollution because – like battery electric vehicles (BEVs) – they have zero tailpipe emissions. As discussed in Chapter 2, hydrogen can be converted to hydrogen-based fuels, including synthetic methane, methanol and ammonia, and synthetic liquid fuels, which have a range of potential transport uses. Synthetic liquid fuels produced from electrolytic hydrogen are often referred to as "power-to-liquid".

The suitability of hydrogen and these hydrogen-based fuels in different transport modes is presented in Table 5, which sets out some of their main advantages and disadvantages.[40] In general, hydrogen-based fuels could take advantage of existing infrastructure with limited changes in the value chain, but at the expense of efficiency losses. Hydrogen-based fuels offer particular advantages for aviation (in the form of synthetic jet fuel) and for shipping (as ammonia), sectors where it is more difficult to use either hydrogen or electricity.

[40] For all applications the volume requirements for on-board storage are a key challenge for hydrogen. While hydrogen contains around three times more energy per kg than fossil fuels, its energy density is eight times lower than these conventional fuels when compressed to typical on-board storage pressures for gaseous hydrogen (70 megapascals).

Table 5. Potential uses of hydrogen and derived products for transport applications

	Current role	Demand perspectives	Future deployment	
			Opportunities	**Challenges**
Cars and vans (light-duty vehicles)	11 200 vehicles in operation, mostly in California, Europe and Japan	The global car stock is expected to continue to grow; hydrogen could capture a part of this market	**Hydrogen:** Short refuelling time, less weight added for energy stored and zero tailpipe emissions. Fuel cells could have a lower material footprint than lithium batteries Captive vehicle fleets can help overcome challenges of low utilisation of refuelling stations; long-distance and heavy-duty are attractive options	**Hydrogen:** Initial low utilisation of refuelling stations raises fuel cost; reductions in fuel cell and storage costs needed; efficiency losses on a well-to-wheels basis **Power-to-liquid:** Large electricity consumption and high production costs **Ammonia:** Caustic and hazardous substance close to end users mean that use is likely to remain limited to professional operators
Trucks and buses (heavy-duty vehicles)	Demonstration and niche markets: ~25 000 forklifts ~500 buses ~400 trucks ~100 vans. Several thousand buses and trucks expected in China* by end-2019	Strong growth segment; long-haul and heavy-duty applications are attractive for hydrogen		
Maritime	Limited to demonstration projects for small ships and on-board power supply in larger vessels	Maritime freight activity set to grow by around 45% to 2030. 2020 air pollution targets and 2050 greenhouse gas targets could promote hydrogen-based fuels	**Hydrogen** and **ammonia** are candidates for both national action on domestic shipping decarbonisation, and the IMO Greenhouse Gas Reduction Strategy, given limitations on the use of other fuels	**Hydrogen:** Storage cost higher than other fuels **Hydrogen/ammonia:** cargo volume lost due to storage (lower density than current liquid fuels)
Rail	Two hydrogen trains in Germany	Rail is a mainstay of transport in many countries	**Hydrogen** trains can be most competitive in rail freight (regional lines with low network utilisation, and cross-border freight)	Rail is the most electrified transport mode; **hydrogen** and battery electric trains with partial line electrification are both options to replace non-electrified operations, which are substantial in many regions
Aviation	Limited to small demonstration projects and feasibility studies	Fastest-growing passenger transport mode. Large storage volume and redesign would be needed for pure hydrogen, making **power-to-liquid** and biofuels more attractive for this mode	**Power-to-liquid:** Limited changes to status quo in distribution, operations and facilities; also maximises biomass use by boosting yield **Hydrogen:** Together with batteries, can supply on-board energy supply at ports and during taxiing	**Power-to-liquid:** Currently 4 to 6 times more expensive than kerosene, decreasing to 1.5–2 times in the long-term (Chapter 2), potentially increasing prices and decreasing demand

* China = People's Republic of China.

Road transport

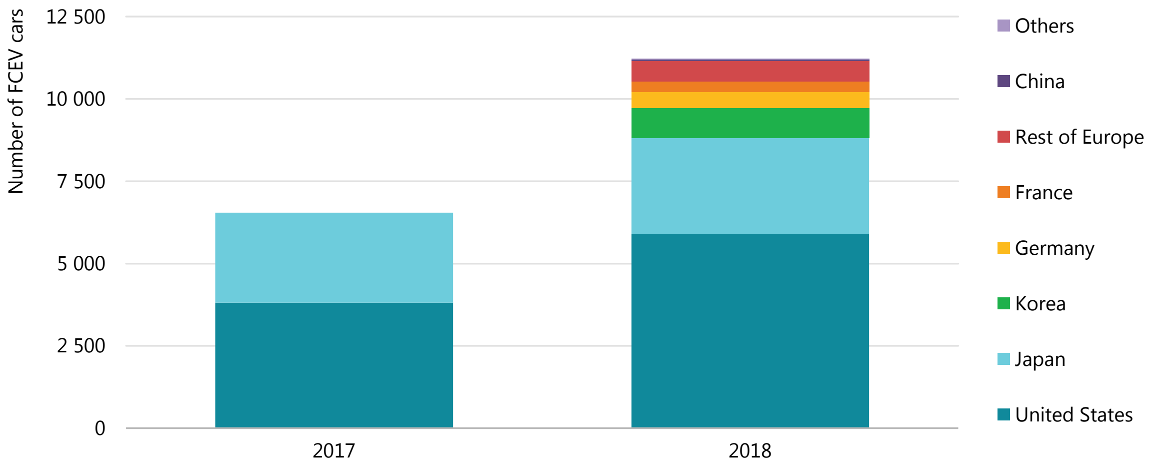
Light-duty FCEVs receive most public attention when it comes to the direct use of hydrogen in mobility applications today. FCEVs have, however, also been deployed for material handling applications (mainly forklifts), buses, trains and trucks.[41]

How is hydrogen used in road transport today?

Cars

Cars account for the vast majority of fuel cell power deployed in road transport (E4tech, 2018). About 4 000 fuel cell electric cars were sold in 2018 to reach a total stock of 11 200 units (Figure 50), an increase of 56% over the previous year (AFC TCP, 2018). This is still a small number compared with the 2018 BEV stock of 5.1 million (IEA, 2019a) or the global car stock of more than 1 billion. The United States accounts for about half of registered FCEVs, followed by Japan (about a quarter), the European Union (11%, primarily in Germany and France) and Korea (8%). Almost all passenger car FCEVs are made by Toyota, Honda and Hyundai, although Mercedes-Benz has recently begun leasing and selling limited volumes of a plug-in hybrid electric vehicle with a fuel cell.

Figure 50. Fuel cell electric cars in circulation, 2017–18



Source: AFC TCP (2019), *AFC TCP Survey on the Number of Fuel Cell Electric Vehicles, Hydrogen Refuelling Stations and Targets*.

About 4 000 fuel cell electric cars were sold in 2018, growth of almost 56% over the previous year, but this still represents a small fraction of the global light-duty vehicle fleet.

Buses, trucks and other goods vehicles

Hydrogen fuel cell electric forklifts are already commercially viable as replacements for existing battery electric forklifts[42] and it is estimated that 25 000 forklifts have fuel cells globally. In the

[41] The success of FCEVs in the forklift market comes from their need to use significant amounts of electricity and the strict tailpipe emissions requirements that they are subject to, since they often operate in enclosed environments where internal combustion engines would result in high human exposure to exhaust gases.

[42] The economics derive from high utilisation, fast charging, small grid charges and better use of capital (i.e. no batteries are offline when being charged). One critical prerequisite is the high utilisation of the hydrogen fuelling station through a captive forklift fleet.

case of buses, the People's Republic of China ("China") has reported the largest deployment, with more than 400 registered by the end of 2018 for demonstration projects (AFC TCP, 2019; Hongxiang, 2018). An estimated 50 fuel cell electric buses were also in operation in Europe in 2017, 25 in California and about 30 in other US states (E4tech, 2018). Other demonstration projects have rolled out fuel cell electric buses in Korea and Japan. Volumes are scaling up rapidly and thousands are expected to be in operation by the end of 2020 (mostly in China).

Globally at least 11 companies currently manufacture fuel cell electric buses. Because their long range means that there is generally no need to recharge during the day, they are in general well suited to: higher daily mileage (above 200 km per day); larger bus fleets, where refuelling can be simpler than recharging battery electric buses; and flexible routing and operations, for example extending a given route at certain periods of the year.

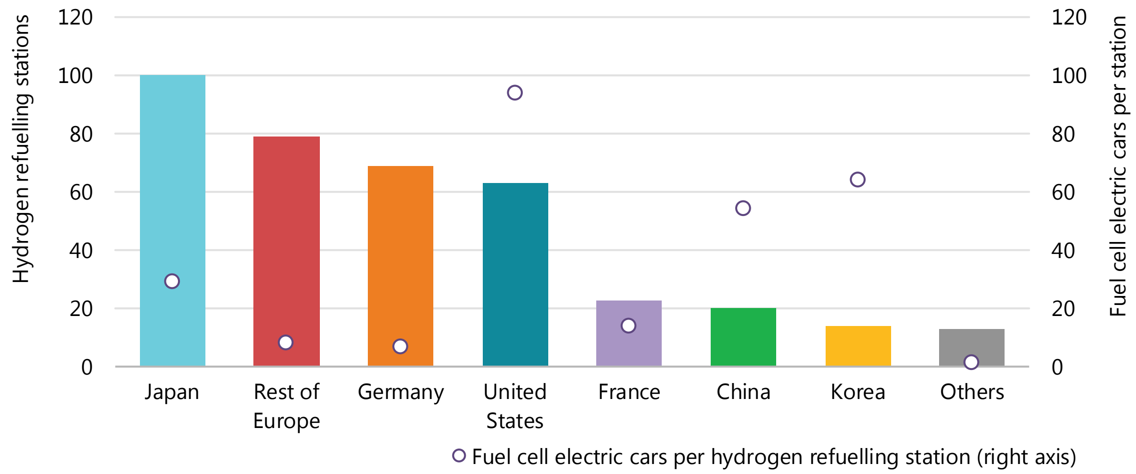
New models of battery electric trucks and buses have recently been produced, purchased and put into operation. The market growth has been fastest in fleets that have access to daily charging opportunities and limited daily ranges (up to 350 km per day), notably urban buses and delivery fleets. Certain operations in these fleets are intensively used and require long ranges, and some fleet owners and operators have found it cost-effective in regions where hydrogen stations exist to install fuel cell range extenders on light- and medium-duty trucks and buses. Intercity buses in particular are likely to be a promising and competitive application for fuel cell electric powertrains.

As regards trucks, China leads the global deployment of fuel cell electric trucks and accounts for the majority of demonstration projects. Country-level statistics in 2018 refer to 412 units registered in China (AFC TCP, 2019), supplemented by 100 vans. Separately 500 hydrogen fuel cell delivery vehicles are reported as operating in the city of Rugao alone and well over 100 are in full daily operation in and around Shanghai (Hongxiang, 2018; E4tech, 2018) . Outside China, FedEx and UPS, two delivery companies, are trialling fuel cell range-extender Class 6 delivery vehicles in the United States, and the h2Share project is planning to test a 27-tonne heavy-duty truck in Europe (E4tech, 2018; H2-Share, 2018) (Box 12). The French postal service and other logistics companies in France have also installed small fuel cells as range extenders onto 300 battery electric vehicles in their fleet, and other companies have brought to market fuel cell range extenders for electric vans in France (AFHYPAC, 2017).

Hydrogen refuelling stations

The installation of hydrogen refuelling infrastructure, while relatively limited to date, has picked up momentum in the past few years. Hydrogen refuelling stations for road transport vehicles, including both publicly accessible and private refuelling points, reached a worldwide total of 381 in 2018 (Figure 51). Japan (100), Germany (69) and the United States (63) are the three countries with the highest numbers of publicly available hydrogen refuelling stations. These are, however, still small numbers compared with those for BEVs: there are almost 144 000 public fast chargers in the world for light-duty vehicles, 395 000 public slow chargers and 4.7 million private chargers (IEA, 2019a). These numbers mean that there are around 10 BEVs for every public charger and one for every private charger; the average number of FCEVs for every hydrogen refuelling station in most regions where they have been deployed is currently much higher (Figure 51). For a fully developed infrastructure, 2 500–3 500 FCEVs per station are expected (Robinius et al., 2018).

Figure 51. Hydrogen refuelling stations and utilisation, 2018



Notes: Hydrogen station numbers include both publicly available and private refuelling units. The number of FCEVs used to estimate the ratio includes only light-duty vehicles, and so does not reflect utilisation of stations by other categories of road vehicles.
Source: AFC TCP (2019), *AFC TCP Survey on the Number of Fuel Cell Electric Vehicles, Hydrogen Refuelling Stations and Targets*.

The ratio of hydrogen refuelling stations to light-duty FCEVs varies considerably across countries, reflecting differences in approaches to deployment, station size, storage pressure and utilisation.

Delivered hydrogen prices are highly sensitive to hydrogen refuelling station utilisation. For example, a ratio close to 10 cars per station (as is the case in Europe) implies that pumps operate less than 10% of the time if the refuelling stations were as small as 50 kgH_2 per day.[43] This translates to a high price of around USD 15–25/kgH_2 if the costs of building and operating refuelling stations are repaid by fuel sales over the lifetime of a station.[44] A higher ratio of cars to refuelling stations implies better co-ordination between vehicle and infrastructure deployment and should lead to lower hydrogen prices. However, some countries with high ratios today have FCEVs that are mostly used as fleet vehicles, with fixed routes and refuelling patterns that are not representative of the needs of more widespread deployment. This is the case in China and France, for example.

The variability of this ratio among countries indicates different approaches to the risks associated with refuelling infrastructure development. Refuelling stations can take as little as six months to bring into operation in China, but generally take up to two years (CEC, 2017). Approaches that try to mitigate the co-ordination problem and time lag related to infrastructure development include using refuelling stations at or near hydrogen production sites (for instance at industrial sites, intermodal interchange hubs or ports) to serve dedicated fleets (such as industrial operations or, potentially, public buses or taxis).

[43] This calculation is based on an annual refuelling volume of hydrogen of 160 kg per year per vehicle and annual mileage of 12 000 km.

[44] While station capacities below 50 kg per day would translate into higher utilisation rates, small stations are capital intensive and would not be able to take advantage of the strong scale economies of refuelling stations. As a result, the cost margin added by refuelling of a station with a capacity of less than 50 kg per day would still be upward of USD 15/kg of hydrogen.

Box 12. Public and private initiatives for hydrogen in road transport

- The leading FCEV car manufacturers today are Toyota and Hyundai, both of whom have ambitious plans for scale-up. Toyota's announced target is to produce over 30 000 fuel cell electric cars annually after 2020, from about 3 000 today (Tajitsu and Shiraki, 2018). Hyundai also has production capacity today of around 3 000 fuel cell systems and aims to increase this to 700 000 by 2030, with 70% for road FCEVs (Kim, 2018).
- Thousands of fuel cell electric buses are lined up for production and are on pre-order for the coming five years, mostly in China. In general, government-supported initiatives directly underpin these orders, including the Fuel Cell and Hydrogen Joint Undertaking in Europe and the National Fuel Cell Bus Program in the United States. In Korea a public–private partnership aims to deploy 1 000 fuel cell electric buses by 2022 on the way to Korea's stated target of 40 000 by 2040 (Study Task Force, 2019). Korea's natural gas-powered bus fleet has 26 000 vehicles, all of which could be converted to hydrogen (O'Dell, 2018). Japan aims to have 100 fuel cell electric buses operating for the Tokyo 2020 Summer Olympics in Japan.
- In the case of trucks, several established truck manufacturers – Hyundai, Scania, Toyota, Volkswagen, Daimler and Groupe PSA – are developing models, as are newer companies such as Nikola Motor Company, founded in 2014. Of these, Hyundai and Nikola are more advanced in terms of orders, with 1 600 Hyundai fuel cell electric trucks (in partnership with H2 Energy) scheduled to roll out in Switzerland and other European countries by 2025 (ACTU, 2019). Nikola has secured substantial funding and a high volume of pre-orders for its semi-trucks, including a recently unveiled European model, the Nikola Tre (Nikola, 2018a; Nikola, 2018b). Both Hyundai and Nikola are closely involved in the supply of hydrogen (largely from renewable electricity) to ensure customers can meet their fuel needs from the outset. Toyota is partnering with the California Air Resources Board and the Ports of Los Angeles and Long Beach to trial its Class 8 truck. In addition, delivery companies such as FedEx, UPS and DHL aim to trial fuel cell range-extender vehicles. StreetScooter (now owned by Deutsche Post DHL Group) aims to have fuel cell range-extended vans in operation by 2020.

Sources: Tajitsu and Shiraki (2018), "Toyota plans to expand production, shrink cost of hydrogen fuel cell vehicles"; Kim (2018), "Hyundai plans $6.7 billion investment to boost fuel-cell output"; Study Task Force (2019), "Hydrogen Roadmap Korea: Presenting a vision, roadmap, and recommendations for Korea's future hydrogen economy"; O'Dell (2018), "2018 is the tipping point for commercial vehicle electrification"; ACTU (2019), ; Nikola (2018a), "Nikola oversubscribes C round with $210 million"; Nikola (2018b), "Nikola raises $100 million in August".

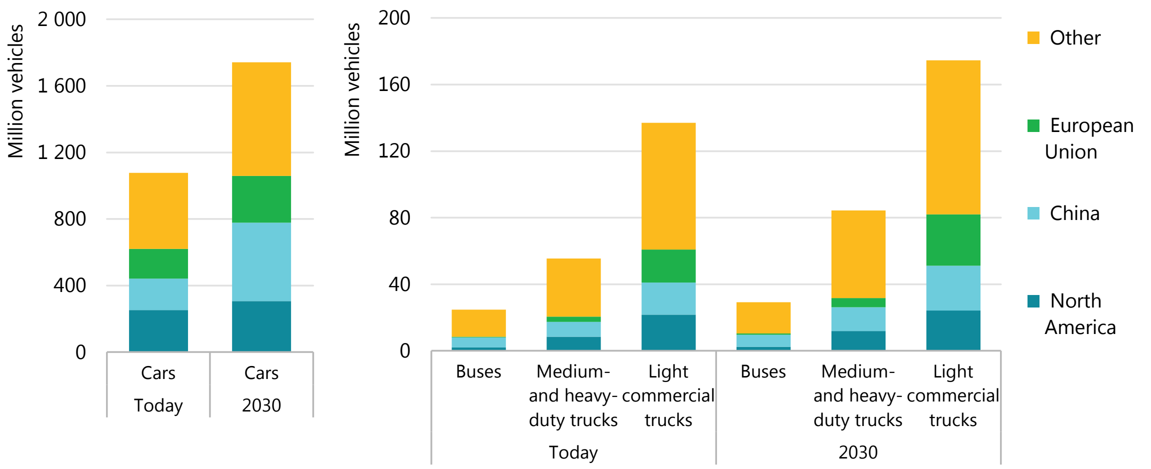
Potential future hydrogen demand in road transport

Together with BEVs, FCEVs are the only vehicles with no exhaust emissions and thus offer the potential to drastically reduce local air pollution, especially in cities. They can also dramatically reduce CO_2 emissions when low-carbon hydrogen is used. The driving range and pattern of refuelling for FCEVs is similar to internal combustion engine vehicles. Furthermore, hydrogen has some attractive attributes compared to biofuels as it does not generally face resource constraints or competition for land use. FCEVs have nevertheless been slow to take off. Technical challenges and high prices have delayed their market introduction. While the Hyundai

Tucson-ix 35 was introduced in 2013 and the Toyota Mirai in 2014, there is a need to further reduce costs and build up refuelling station networks concurrently with vehicle uptake if more automakers are to be attracted to the market.

The theoretical potential for future use of hydrogen in road transport is very large. Any road transport mode can technically be powered using hydrogen, either directly using fuel cells or via hydrogen-based fuels in internal combustion engines. As an indication of the size of this market, if all the 1 billion cars, 190 million trucks and 25 million buses currently on the road globally were replaced by FCEVs, hydrogen demand would be as high as 300 MtH_2/yr, more than four times current global demand for pure hydrogen (Figure 52). The theoretical potential future demand is even larger. Over the next 10 years to 2030, oil demand from road transport is set to grow by 10% without strong action to meet the goals of the Paris Agreement. In particular, this would be driven by demand for trucks in emerging economies, but also rising car ownership. Car ownership in countries like India and even China is well below that of industrialised countries such as the European Union and the United States. US per-capita car ownership is 25 times higher than India's.

Figure 52. Road vehicle fleet growth to 2030 under current trends



Source: IEA 2019. All rights reserved.

The road vehicle fleet's current fuel demand is large, and is set to grow with demand for personal mobility by car and goods delivery by truck, particularly in developing and emerging economies.

While the theoretical potential is very large, actual deployment will depend very strongly on the interactions between vehicle costs, fuel costs and policies, as well as the cost of alternatives and evolving driving habits in different countries.

Cost competitiveness of direct and indirect uses of hydrogen in road transport

The following section discusses the contribution of various different components to the cost of hydrogen FCEVs. It does so as a means of identifying key opportunities for cost reductions and of understanding the most promising applications for FCEVs compared with other options, in particular BEVs. It should be noted, however, that from the perspective of consumers, the cost of the vehicle is just one of many decision criteria. Car buyers tend to base vehicle purchase decisions on a number of criteria, including performance, comfort, perceived reliability and brand. The choice of what vehicle to buy, in other words, is not by any means just a matter of costs or price, or a comparative calculation of the total cost of owning and operating a vehicle. Both BEVs and FCEVs have some shared characteristics (such as zero tailpipe emissions, fast acceleration from a standing start and quiet operation) that may appeal to consumers while advancing a wider transition towards the use of low-carbon fuels in transport. They also have some different performance attributes that are likely to appeal to distinct consumer groups.

Leaving aside the cost of hydrogen fuel, which is discussed in Chapters 2 and 3, the cost competitiveness of direct hydrogen use in FCEVs depends on how three critical cost components develop compared with their present and potential future competitors: the cost of the fuel cell stack; the cost of on-board storage; and the cost of refuelling.

Fuel cell costs and potential for cost reduction

The fuel cell has seen considerable cost reductions over the past decade (Yumiya, 2015), but costs remain high and production volumes are still low. The current commercial cost of a typical fuel cell is estimated to be USD 230/kW, although the use of state-of-the-art technologies is soon likely to bring this cost down to USD 180/kW (Papageorgopoulos, 2017).

Costs could be further reduced in the future through research-driven advances in technology. It may be possible to increase catalyst activity and thus reduce the platinum content, which is one of the expensive components of the fuel cell. It may also be possible to develop a platinum-free catalyst. Research is also needed to optimise the design and integration of fuel cell components in the membrane electrode assembly and to decrease the costs of the bipolar plates (which are expected to account for an increasing share of the future costs) and balance of plant components (e.g. compressors and humidifiers).

Costs could also be reduced in the future through economies of scale: increasing the number of units fabricated in a single manufacturing plant reduces the specific cost of each component. About half of the system cost is in the bipolar plates, membranes, catalyst and gas diffusion layers. The combined cost of these components could be reduced by 65% by increasing plant scale from 1 000 to 100 000 units per year, bringing system costs down to USD 50/kW. Increasing the scale further to 500 000 units per year would be likely to decrease the cost by only an additional 10%, taking it down to USD 45/kW (Wilson, Kleen and Papageorgopoulos, 2017). These cost reduction estimates must, however, be balanced against the challenge of simultaneously improving fuel cell performance and durability. Higher durability requirements could translate into higher fuel cell cost and limit the cost reductions achieved through economies of scale. Recent US Department of Energy (DOE) data take into account these trade-offs and provide a preliminary durability-adjusted cost target of USD 75/kW (US DOE, 2019) . However, automakers are working to increase durability, such as via constructing fuel cell operation maps to mitigate performance degradation.

Economies of scale in manufacturing could be achieved quickly. Global truck sales stood at around 1.6 million medium-duty and 1.8 million heavy-duty vehicles in 2017. A medium-duty truck requires about twice as much power as a car, and a heavy-duty truck needs about four times as much. These requirements could, however, be met by installing fuel cell stacks next to each other; the most cost-effective way of proceeding might be to equip a medium-duty fuel cell electric truck with two fuel cell stacks, and a heavy-duty truck with four. To reach a 5% global market share in trucks would require five fuel cell system plants producing 100 000 units (stacks) a year. China would need 10 plants producing 100 000 units annually to satisfy just a quarter of its current annual sales for domestic medium- and heavy-duty trucks. The passenger vehicle sector has a market size much larger than trucks, with annual new car sales of around

85 million and light commercial truck sales of 10 million in 2017. These light-duty vehicles require a system consisting of a single fuel cell stack, with a peak power of 80–100 kW per vehicle. Achieving a market share of 5% of the global car market would require 40 fuel cell manufacturing plants, each with an average output of 100 000 units a year.

Storage tank costs and potential for cost reduction

On-board storage tank costs are determined by expensive composite materials and are expected to fall at a slower pace than fuel cells. On-board storage of hydrogen requires it to be compressed at 350–700 bar for cars and trucks, and this uses the equivalent of 6–15% of the hydrogen energy content.[45] The costs of current on-board storage systems (including fittings, valves and regulators) are estimated at USD 23/kWh of useable hydrogen storage at a scale of 10 000 units per year, decreasing to USD 14–18/kWh at a scale of 500 000 units per year (Vijayagopal, Kim and Rousseau, 2017). The US DOE has an ultimate target of USD 8/kWh. For a car with a range of 600 km, this implies costs of around USD 3 400 today and USD 1 800 in the long term for a tank of 225 kWh. For a heavy-duty truck with a range of 700 km, it implies costs of USD 27 700 today and a potential reduction to USD 16 700 for a tank of 1 800 kWh, compared with USD 100 000 – 150 000 for the full cost of a conventional diesel truck tractor.

Refuelling infrastructure costs and potential for cost reduction

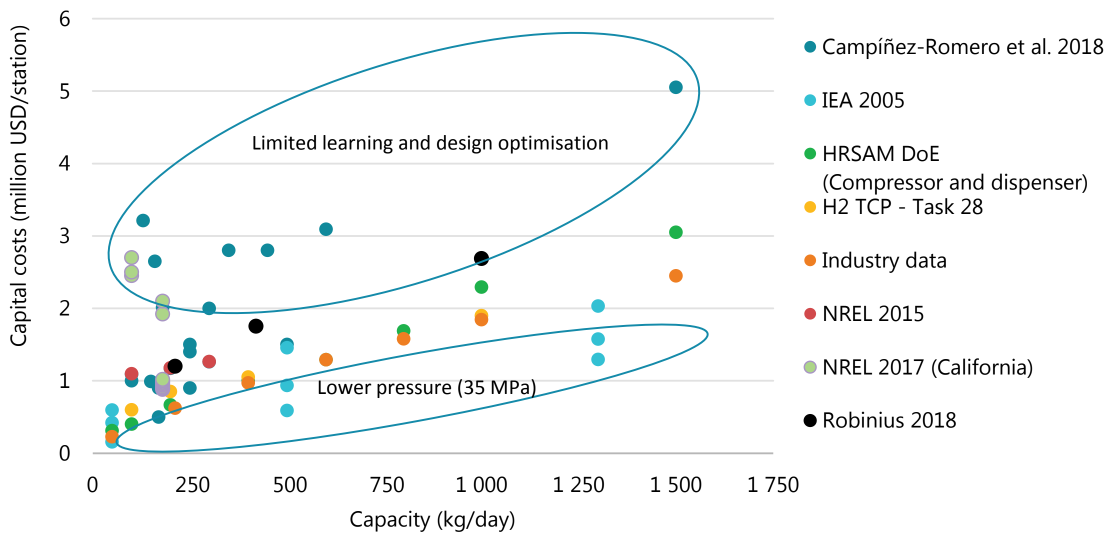
The roll-out of hydrogen refuelling infrastructure is a key requirement for FCEVs. Hydrogen refuelling takes almost as little time as refuelling conventional liquid transport fuels. Supplying refuelling stations with hydrogen, however, may require more time and labour than is the case for conventional transport fuels. Validation of cost estimates is difficult because there are fewer than 400 hydrogen refuelling stations around the world and because their data are usually not disclosed. However, investment costs for hydrogen refuelling stations are estimated to be in the range of USD 0.6–2 million for hydrogen at a pressure of 700 bar, and USD 0.15–1.6 million at 350 bar (Figure 53). The lower end of these ranges is for stations with a capacity of 50 kgH_2/day while the upper is for 1 300 kgH_2/day.[46]

The two largest cost components are the compressor (which can be up to 60% of the total cost when the delivery pressure is 700 bar) to achieve the delivery pressure, and the storage tanks (which are relatively large due to lower hydrogen density). The actual cost of building a station varies considerably across countries, mainly as a result of different safety and permitting requirements. There are strong economies of scale. Increasing the capacity from 50 to 500 kgH_2/day would be likely to reduce the specific cost (i.e. the capital cost per kg of hydrogen dispensed) by 75%. Larger capacity stations of up to a few 1 000 kgH_2/day are being planned, especially for heavy-duty applications, and these offer potential for further economies of scale. There is also potential for costs to be reduced through a shift to more advanced supply options (such as very high pressure or liquid hydrogen) and through scale-up in the manufacturing of refuelling station products (via mass production of components, such as the compressors).

[45] Even at 700 bar it is important to note that hydrogen storage needs seven times more space to achieve the same range as conventional diesel technology.

[46] The total cost of the engineering, construction and general overheads for hydrogen refuelling stations with the capacity to deliver 130 kg to 350 kg per day of hydrogen falls in a higher range (USD 2.4–USD 3.2 million) (Baronas et al., 2017)

Figure 53. Benchmarking hydrogen refuelling station capital costs as a function of capacity



Sources: Campíñez-Romero et al. (2018), "A hydrogen refuelling stations infrastructure deployment for cities supported on fuel cell taxi roll-out"; IEA (2005), *Prospects for Hydrogen and Fuel Cells*; Pratt et al. (2015), *H2FIRST Reference Station Design Task*; US DOE (2018) HRSAM DoE; industry data, Robinius et al. (2018), "Comparative analysis of infrastructures: Hydrogen fueling and electricity charging of vehicles".

The costs of providing hydrogen to FCEVs can be brought down by building larger refuelling stations as long as expected hydrogen demand allows.

Risks related to the tension between refuelling station size, the cost of hydrogen and hydrogen demand are among the barriers to rapid hydrogen uptake for transport. Small stations make more economic sense in the initial deployment phase as they are more likely to secure higher capacity utilisation rates when demand for hydrogen from transport vehicles is limited, but they come at higher cost per unit of hydrogen delivered. Once sufficient demand volumes have been established, larger stations become more economic and can help reduce the cost of hydrogen for the end users. The cost of delivered hydrogen will also depend on whether the hydrogen is produced locally or delivered from centralised production facilities. The cost advantages of centralised production may be outweighed by the cost of distribution to the refuelling station by truck or pipeline (Chapter 3). The cheapest option will be determined case by case.

Despite higher initial costs than BEV charging infrastructure, hydrogen refuelling stations can offer significant advantages when deployed at scale, such as faster refuelling and space requirements around 15 times lower, as well as potentially lower final investment costs (FCH2 JU, 2019). In the longer term over 400 refuelling stations would be needed to service a fleet of 1 million hydrogen FCEVs if the ratio of refuelling stations to cars were similar to that for today's oil-powered car fleet (FuelsEurope, 2018; ACEA, 2018; Robinius et al. 2018). This compares to almost 1 million private charging stations and at least 10 000 fast-charging public stations that would be needed for a fleet of 1 million BEVs.

To meet the needs of a growing FCEV fleet, policy makers will need to ensure investment flows at the right times. Most fuelling stations serving non-captive fleets in the early stages of FCEV deployment will be small (< 200 kgH_2/day), and the total investment needed to build these

400 stations is likely to be on the order of USD 0.5–0.6 billion. This would rapidly increase, however, and for a mature market with larger stations (> 1 000 kg/d) an investment of USD 35–45 billion[47] would be required to serve just 5% of the global car fleet (around 60 million vehicles). As well as collaborating with industrial stakeholders on roadmaps for building refuelling stations in the initial phases, before their revenue can sustain investment in expansion, policy makers could incentivise owners of captive fleet stations to open them for public use, thus allowing general users to access more stations (Box 13).

Box 13. Policy opportunities for promoting the use of hydrogen in road transport

Policy options to promote the uptake of FCEVs include fuel economy standards, zero-emission vehicle (ZEV) mandates, feebates (which tax the worst performing vehicles to subsidise those that perform best in terms of CO_2 or air pollutant emissions) and purchase subsidies. The first two put the onus on private industry to provide technological solutions to climate and air quality externalities and give them the freedom to find the solutions that work best for them. Fuel economy standards and feebates can be technology-neutral, while ZEV mandates are more specific and could help to secure the demand that hydrogen refuelling stations need to bring down the costs of delivering hydrogen during an initial deployment phase.

Focusing initially on building refuelling infrastructure for captive fleets would provide a way to address the barrier of underutilisation. Examples of captive fleets include truck and handling vehicles at industrial sites and clusters and at ports; buses; and taxi fleets. Refuelling stations originally built for captive fleets could be opened for public use, thereby offering refuelling points to early adopters of FCEVs at a low marginal cost. An alternative approach would be to give credits to refuelling stations (under fuel standards) based on the gap between actual and targeted utilisation rates, as in California where a range of policy instruments combine to support private investment in refuelling infrastructure (CEC and CARB, 2018).

Public policy can also play a supportive role in the initial stages by:

- Easing regulatory burdens associated with the transport of hydrogen (e.g. in vehicles on bridges and tunnels) and with the permitting and construction of necessary infrastructure.
- Engaging with industry stakeholders that are able to make the required investments, brokering commitments among industry partners to support credible and well-structured business plans, and offering a critical assessment (e.g. based on audits) of areas for improvement of such plans at regular intervals.
- Temporarily repurposing funds from vehicle or fuel taxes to decrease the investment risk of nascent hydrogen refuelling station networks.

Source: CEC and CARB (2018).

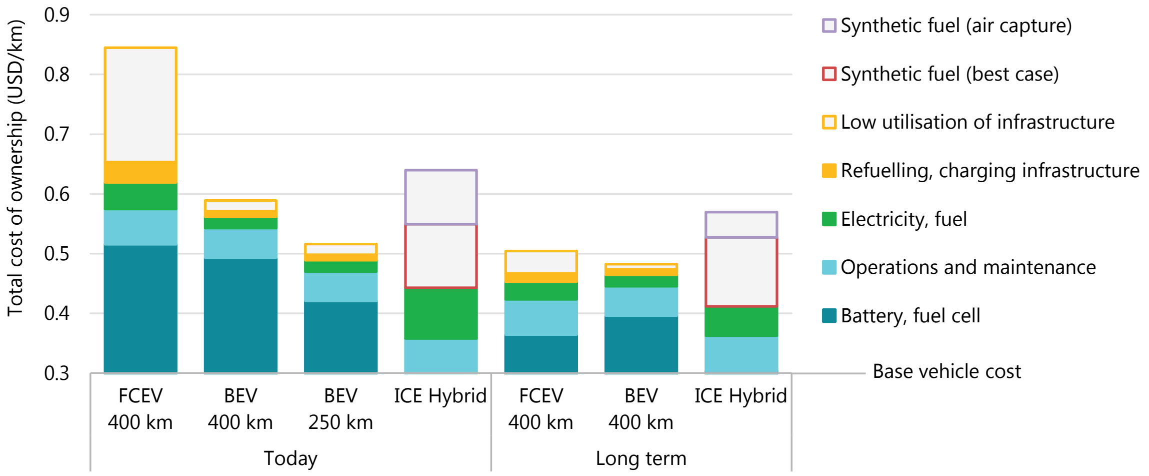
[47] Assuming 20% of stations would be small scale (200 kg/day) and 80% would be large scale (1000 kg/day) as the market developed.

Total cost of ownership of cars

Energy consumption per kilometre tends to be greatest on large vehicles used over long distances. This means that fuel costs generally make up a greater share of total costs for heavier vehicles, and for vehicles with high utilisation (such as long-haul trucks, intercity buses and commercial car fleets). As the capital cost of a car ranges from 70% to 95% of the total cost of ownership, depending on the vehicle, it will be imperative to bring down the cost of fuel cell systems and hydrogen storage tanks to achieve cost competitiveness with other options. The case is somewhat different for trucks, for which the capital cost ranges from 40% to 70% of the total ownership cost, meaning that cost reductions for delivered hydrogen are just as important (see section on medium- and heavy-duty vehicles below).

Car buyers typically consider the total cost of ownership as one among several decision criteria. For example, the range of a car can be important to some buyers. The global average BEV sold today has a range of around 250 km; this is sufficient for most daily trips. FCEVs sold today offer a longer range: the Toyota Mirai offers some 400 km and the Hyundai Nexo even more. This makes them attractive for consumers who prioritise range.[48] To illustrate the relevance, assuming hydrogen refuelling facilities are located along desired routes, FCEVs could drive from Paris to Marseille (about 750 km) with a single short refuelling stop. The same trip in a BEV with a range of 250 km would require stopping to charge at least twice, with fast charging depending on the availability of stations. This extra range offered by FCEVs, however, comes at a price in terms of the cost of the vehicle. Different consumers will weigh the considerations differently, according to their individual priorities and preferences.

Figure 54. Total cost of car ownership by powertrain, range and fuel



Notes: ICE = internal combustion engine. The y-axis intercept of the figure corresponds to base vehicle "glider" plus minor component costs, which are mostly invariant across powertrains. More information on the assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

FCEV costs could break even with BEV costs at a range of 400 km. Cost reductions in fuel cells and storage tanks, together with high utilisation of stations, are the keys to achieving competitiveness.

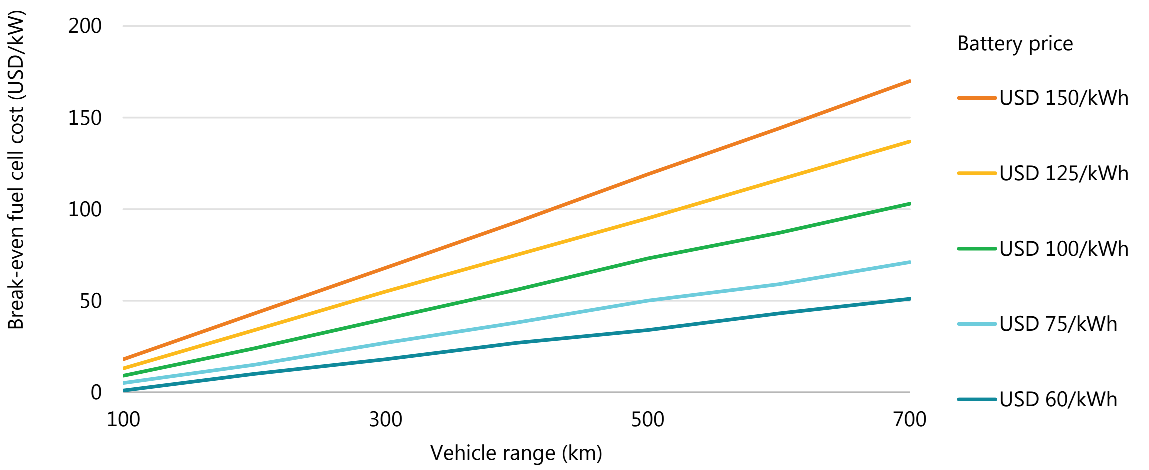
[48] Real-world driving ranges of BEVs are also more sensitive to temperature and use of auxiliary systems (e.g. air conditioning) than other powertrains.

Currently hydrogen fuel cell cars are generally more expensive than battery electric cars, owing to the high cost of the fuel cell and fuel tanks and to the fact that they are generally designed to have a longer range (Figure 54). The competitiveness improves if one assumes the same range for FCEVs and BEVs, although such range would be only possible today for a limited number of BEV models. If cost reductions through economies of scale were to bring down fuel cell costs to USD 50/kW and those of batteries fall to USD 100/kWh, then FCEVs become competitive with BEVs at a range of 400 km. If fuel cell costs were only to fall to USD 75/kW, for example because of the need for durability requirements as discussed earlier in this chapter, then FCEVs would become competitive with BEVs at a range of 500 km (Figure 55). This underscores the fact that FCEVs can be economically attractive for consumers who prioritise driving range.

Utilisation of refuelling infrastructure is another determinant of the future competitiveness of FCEVs. In the initial roll-out phase, the cost of hydrogen fuel can be expected to range from 12% (at USD 9/kgH_2) to 22% (at USD 18/kgH_2) of the total cost of ownership. As discussed above, the additional cost accounted for by the hydrogen refuelling station depends on size and utilisation: stations with a capacity of 200 kgH_2 per day that dispense fuel at 10–33% of capacity add a margin of USD 4–13/kgH_2, and that margin declines with station size and higher capacity utilisation. The risk of underutilised hydrogen refuelling stations highlights the importance of securing high utilisation to bring down costs in the initial stages of FCEV deployment, even in cars, the mode where fuel costs are least determinant.

It is worth noting that in California it took around two years to increase the average utilisation of the network from 5% to 40%; the average station size is now around 200 kgH_2/d (CEC and CARB, 2018) and some stations are still operating at below 10% utilisation (NREL, 2019). The high cost of synthetic fuel, however, suggests that transitioning to alternative powertrains – whether battery or fuel cell electric – is likely to be a lower-cost strategy for reducing CO_2 and local pollutant emissions from cars and trucks, also considering the significant energy consumption and need for biogenic CO_2 this route would require.

Figure 55. Break-even fuel cell cost to be competitive with BEV in the long term



Note: More information on the assumptions is available at www.iea.org/hydrogen2019.
Source: IEA 2019. All rights reserved.

Fuel cell electric cars are most competitive on a total cost of ownership basis with BEV cars over longer driving ranges. To break even with battery costs below USD 100/kWh could require achieving fuel cell costs below USD 60/kW.

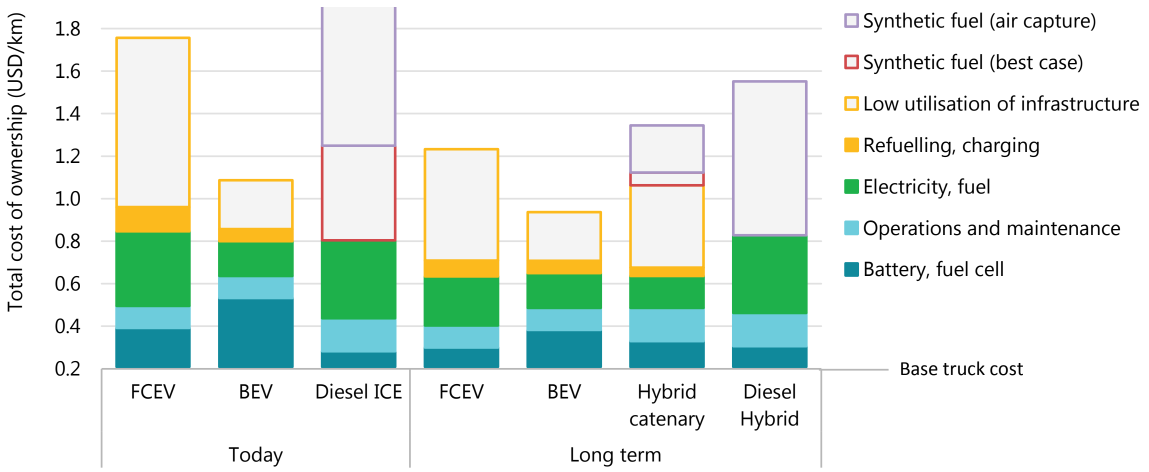
The above analysis suggests that BEVs and FCEVs could complement each other as alternative options satisfying different consumers, with FCEVs offering the best opportunities for vehicles driven at long ranges, with fast refuelling requirements and in regions with access to cheap hydrogen. Furthermore, it suggests that once a hydrogen refuelling infrastructure has been built out, light-duty FCEVs with different configurations (e.g. fuel cell range extenders) could take advantage of cost and performance improvements in both fuel cells and batteries.

Total cost of ownership of medium- and heavy-duty vehicles

The heavy-duty long-haul segment, including trucks and intercity buses (or "coaches"), offers strong prospects for hydrogen FCEVs because it calls for long range and high power requirements. As a result, heavy-duty FCEVs tend to be more immediately competitive against BEVs than in the case of cars. The direct electrification of regional bus operations and heavy-duty trucking for long-distance freight both face major challenges with larger battery capacity, long charging times and high power requirements that translate into payload loss and additional recharging infrastructure costs. Fuel cellelectric trucks overcome some of these challenges.

In the case of heavy-duty long-haul trucks, fuel cell costs are higher than light-duty vehicle applications, mainly as a result of high durability requirements. This currently necessitates increased catalyst loading, translating into higher costs. Future fuel cell system costs for heavy-duty trucks are estimated at USD 95/kW (for a production volume of 100 000 units per year) (US DOE, 2019). Even with current fuel cell costs, FCEVs could in general be competitive against BEVs in heavy-duty applications at ranges of more than 600 km if hydrogen could be delivered at less than USD 7/kgH_2, although the exact hydrogen price at which they become competitive depends on overall annual mileage and other operational characteristics.

Figure 56. Current and future total cost of ownership of fuel/powertrain alternatives in long-haul trucks



Notes: The y-axis intercept of the figure corresponds to base vehicle "glider" plus minor component costs. Infrastructure covers stations, charging points and catenary lines. More information on the assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

Fuel costs make up about half of the total cost of ownership for heavy-duty trucks, so the focus for making them competitive should be on bringing down the delivered price of hydrogen.

Powertrain and fuel options for decarbonising heavy-duty long-haul trucking include FCEVs, battery electric trucks, dynamic charging (catenaries are the most commercially advanced and lowest-cost option on existing roads)[49] and conventional diesel hybrids using synthetic fuels (or advanced biofuels). Figure 56 considers diesel hybrids with 25 km of electric range on catenaries. A range of low-carbon powertrain options could conceivably co-exist: plug-in hybrid electric vehicles, BEVs with or without fuel cell range extenders and FCEVs of different configurations could be designed and ordered to cater to different mission profiles.

Bringing down fuel cell costs to USD 95/kW could make hydrogen fuel cell trucks in the heavy-duty segment competitive with diesel hybrid trucks at a hydrogen price of around USD 7/kgH_2, compared with the price of USD 5/kg currently needed to make them competitive with an ICE truck running on diesel. For fuel cell electric trucks to be competitive with electric road systems or battery electric trucks at a range of less than 500 km, however, the hydrogen price would need to be less than USD 5/kg H_2. Because of the limited size of the truck market, reaching this fuel cell cost target may not be feasible by deployment of fuel cells in trucks alone and will most likely rely on substantial deployment of fuel cells in cars. Fuel cell production for small mobile equipment, such as forklifts, may also help to bring down costs, but since the power requirements of this equipment is typically less than one-third that of a car, high production volumes of roughly 3 000 units per year would be needed to achieve cost reductions below USD 80/kW.

In the case of trucks (and also buses), the cost contribution from the infrastructure could be reduced by the operation of a "hub-and-spoke" model: a dedicated fleet operating on fixed routes could refuel at a single centralised hydrogen refuelling station. Since refineries and industrial clusters are often co-located at ports, port operations (and handling equipment) offer further attractive initial markets. The efficiency of these strategies has been demonstrated by the rapid adoption of hydrogen fuel cell electric buses and trucks in China, where the business case for intensive medium- and heavy-duty operations has been strengthened considerably by success in accessing low-cost hydrogen and achieving high utilisation rates of refuelling stations.

The maritime sector: Ships and ports

The maritime sector is an important consumer of oil products, accounting for around 5% of global oil demand. This section of the report focuses on international shipping, which is the cheapest way to move long-distance freight. By volume around 90% of global physical trade in goods is by sea, of which one-third is energy products, in particular oil products (IMO, 2014). About 80% of fuel use in the maritime sector is in international shipping, of which 90% is used for maritime freight. As a result, international shipping is an important contributor to climate change: it is responsible for around 2.5% of global energy-related CO_2 emissions. As it uses heavy fuel oil, it also has large detrimental effects on air quality, notably around ports. Hydrogen, mostly in the form of hydrogen-based fuels, is a leading option for tackling these challenges in international shipping. One advantage of these applications is that they offer the opportunity to address not only emissions during sea transport, but also those arising from port operations, making use of synergies with forklifts, trucks and goods movement in

[49] Catenary lines could provide energy to a diverse range of powertrains, including diesel hybrid electric vehicles, FCEVs and BEVs. However, they require the installation of substations and overhead catenary lines as well as retractable pantographs on trucks, increasing the investment risk. It is not clear how these costs would compare with the costs of fuel cell trucks or indeed battery electric trucks. Much like hydrogen, with a high enough utilisation rate of energy provision infrastructure, these costs can be offset by the cost and operational benefits of smaller batteries.

and around ports (see Chapter 6). Opportunities also exist to use hydrogen and fuel cells for shorter routes within national jurisdictions, especially those operated by ferries.

How is hydrogen used in the maritime sector today?

Oil products currently dominate the shipping sector, and the use of hydrogen-based fuels in shipping is accordingly very limited. There is, however, one project in Belgium for co-firing hydrogen with diesel in maritime internal combustion engines, and more than 20 projects for fuel cells of up to 300 kW, mostly for auxiliary power units (DNV GL, 2017). Projects using fuel cells, often in combination with batteries, are planned in California (GGZEM, 2018), Ireland, Norway (AirClim, 2018) and for some Europe-wide operations.

Ships do not use ammonia as fuel today, but ammonia containing the equivalent of around 3.5 MtH_2/yr is traded in ships. Several research and demonstration projects are looking at the firing of ammonia as fuel for ships (Brown, 2018). Satisfactory combustion of ammonia in existing engines would generally require ignition promotors (to overcome its lower ignition energy) and engine modifications.

Potential for hydrogen-based fuels in the maritime sector

The volume of international shipping is expected to more than triple by 2050 under current trends. In the absence of climate change mitigation policies, this could lead to a 50% increase in demand for oil products in the sector, to around 6 mb/d. Action to reduce the emissions associated with this oil use could open a pathway to the use of hydrogen-based fuels. The International Maritime Organization (IMO) has put in place strategies for reducing both sulphur and greenhouse gas emissions.

Possible measures to address the challenge of reducing sulphur emissions are the installation of scrubbers, fuel switching to LNG and the use of very low sulphur fuel oil (VLSFO), although these measures will only make a partial contribution to the 50% greenhouse gas reduction target by 2050 compared to 1990. As described in Chapter 4, limitations on sulphur emissions are likely to stimulate demand for hydrogen at refineries rather than as shipping fuel. To achieve the greenhouse gas emissions target, advanced biofuels, hydrogen and ammonia are all options, as well as hydrogen-based synthetic liquid fuels. The choice of fuel switching relies on infrastructure deployment outside the direct control of ship owners. LNG, hydrogen and ammonia would require the development of bunkering facilities, while both LNG and ammonia could build upon the existing distribution network. Availability and costs of advanced biofuels are uncertain as there is demand competition from other sectors for a limited supply of sustainable biomass.

Targets are also in place in some countries for low-carbon alternatives in domestic shipping. Sweden and Norway are two examples of this, while the European Commission is developing a strategy to set CO_2 reduction targets for maritime transport based on monitoring, reporting and verification of CO_2 emissions from large ships. Shipping may be incorporated into the European Emission Trading System from 2023.

Among businesses, Maersk, the world's largest maritime company, announced in 2018 that it aims to become carbon neutral by 2050. To achieve this, it recognises that low-carbon vessels will need to be commercially viable by 2030 (Jacobsen, 2018). Industry leaders have also drafted an action plan to decarbonise the shipping sector, which includes demonstration projects, technology adoption, transparency and knowledge sharing (UNFCCC, 2017).

Cost competitiveness of hydrogen-based fuels in the maritime sector

Ships have high per-kilometre energy intensity and large power needs (up to 130 MW for the largest container ships), and therefore pose demanding fuel requirements. The main cost components for ships are the same as for road transport: infrastructure (bunkering facilities), on-board equipment (fuel cell/engine and storage) and fuel.

Information on the costs of using liquid hydrogen for international shipping is uncertain. One estimate for the additional cost of bunkering facilities suggests that liquid hydrogen infrastructure could be 30% more expensive than LNG (Taljegard et al., 2014). However, this estimate is likely to omit the upfront costs associated with developing a new infrastructure for hydrogen that does not currently exist. The main cost components are the storage and bunker vessels, which would need to be scaled in parallel with the number of ships serviced. On-site or nearby hydrogen would be needed for small ports given the smaller flows and the high cost of dedicated hydrogen pipelines. Conversely, ship and infrastructure costs are a relatively small component of total shipping costs over a 15-year lifetime, with fuel costs being a much larger factor.

Among hydrogen-based fuels, ammonia is already globally traded and some of the infrastructure that would be needed to use it as a fuel already exists (distribution to ports and storage tanks). However, new bunkering facilities would need to be built; massive scale-up of ammonia production, port and distribution facilities and storage tanks would also be needed. As an indication, satisfying shipping demand in the long term would require 500 Mt of ammonia, almost three times the level of current global production and around thirty times the volume of ammonia currently traded.

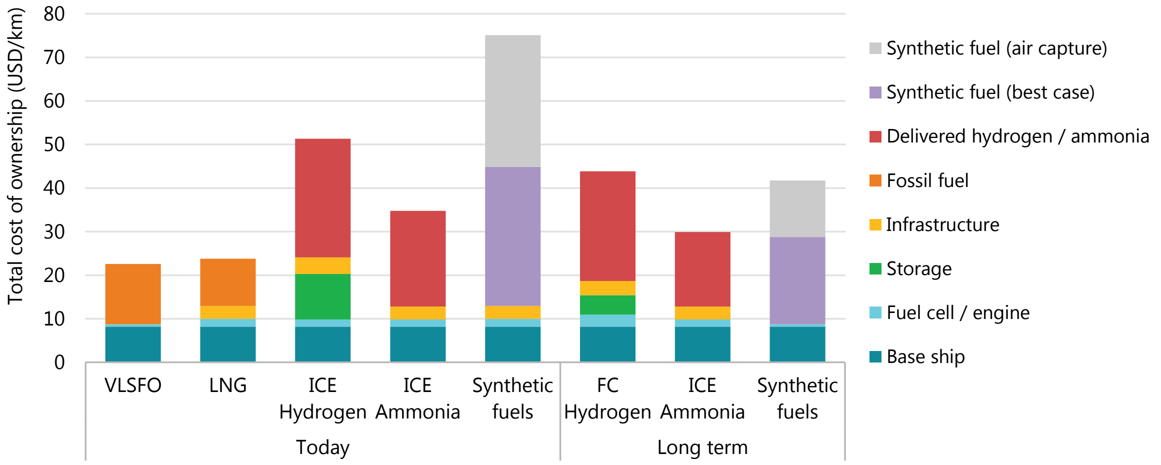
A switch to low-carbon fuels seems unlikely to occur in the absence of policy, whether mandates, direct carbon pricing, and/or more flexible and potentially more palatable measures such as low-carbon fuel standards (LCFS) (ITF, 2018). Charterers, who currently oversee more than half of container fleet operations and who hire vessels from ship owners on a lump-sum or per-tonne basis, are likely to operate much shorter payback periods.

Ships serving long-distance maritime trade routes may offer the best potential scope for hydrogen, ammonia and other hydrogen-based fuels. This is because fuel cell system and hydrogen storage costs have a comparatively lower impact when compared to fuel costs (Figure 57). In addition, the space requirements of fuel cells could be an issue, especially for smaller ships (< 2 MW), as they need almost double the space of an ICE (Minnehan and Pratt, 2017; van Biert et al., 2016). Storage of liquid hydrogen requires at least five times more volume than conventional oil-based fuels, and ammonia requires three times more volume. In the longer term this could require the redesign of ships, shorter distance trips and more frequent refuelling, reduced cargo volumes, or a mix of these operational factors, depending on ship and cargo types and routes (UMAS, 2018).

Low-carbon fuels are expensive today compared with fuel oil and LNG (Figure 57). Fuel prices are the key to cost competitiveness; the share of total cost that comes from infrastructure is much lower for ships than for other transport modes, currently accounting for about 3% of the total cost of using hydrogen in shipping on the basis of a hydrogen price of USD 10/kgH_2. This would rise to 17% if hydrogen prices were to decrease to USD 2/kgH_2, and could be significantly higher (up to 40%) if bunkering facilities were oversized or underutilised. As for road transport, risks of underutilisation of bunkering facilities can be hedged by: rolling out smaller vessels; using smaller storage tanks (which can be expanded as the capacity grows);

using tank trucks to fuel ships; and using a smaller refuelling station. However, to lower fuel costs, larger facilities would be needed for more widespread deployment.

Figure 57. Current and future total cost of ownership of fuel/powertrain alternatives in a bulk carrier ship



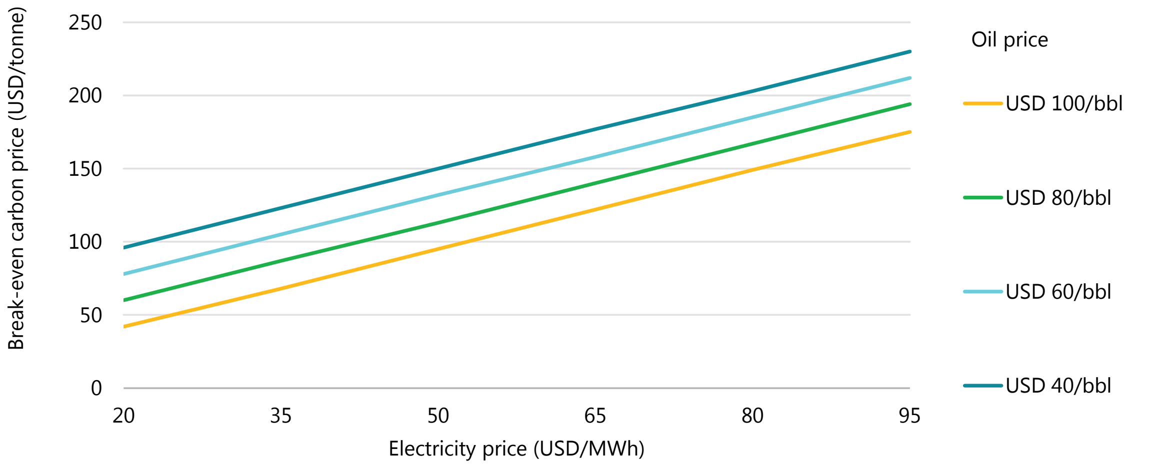
Note: More information on the assumptions is available at www.iea.org/hydrogen2019.
Source: IEA 2019. All rights reserved.

Due to the cost of liquefying and high storage costs, hydrogen is likely to be more costly than other low-carbon alternatives for long-distance maritime transport.

In a 15-year first-owner lifetime calculation, a CO_2 price of USD 40–230/tCO_2 would be required to make ammonia cost-competitive with fossil-based fuels, depending on the delivered cost of ammonia, which will vary by region (Figure 58). The break-even carbon prices for hydrogen are USD 35–45/tCO_2 higher than ammonia, mainly due to the higher storage cost resulting from its lower energy density.[50] It would represent a substantial cost increase for the ship owner and the switch would require policies that have an effect equivalent to these CO_2 prices across competing fleets, for example mandates or low-carbon fuel standards. However, the impact of passing these costs on to the final consumer would be limited because transport costs represent a small share (often less than 1%) of the total price of shipped goods (ETC, 2018a).

[50] This value would be higher for a charterer looking for three-year payback (charterers currently oversee more than half of container fleet operations (Global Ship Lease, 2019).

Figure 58. Break-even carbon price for ammonia to be competitive with fossil fuels



Note: More information on the assumptions is available at www.iea.org/hydrogen2019.
Source: IEA 2019. All rights reserved.

For a bulk carrier, policies equivalent to a carbon price of USD 40–230/tCO_2 would be needed to make ICE engines running on ammonia competitive with fuel oil. The break-even carbon price is highly sensitive to both the oil price and electricity price.

Rail

Rail is already the most electrified mode of transport. Although the percentage share of electrified tracks is still expanding in most countries, further electrification of rail networks is likely to come up against diminishing returns on investment, since highly utilised lines are the first to be electrified (IEA, 2019b). In France and Germany, for example, electrified lines now carry over 80% of traffic, even though less than half of the railway network has been electrified (European Commission, 2016). Beyond bi-mode diesel-electric options, several technologies offer zero tailpipe emissions on non-electrified tracks and the industry seems set to move towards these in the coming decades. The most innovative of such technologies are battery electric trains and hydrogen fuel cell trains. Battery electric trains with smaller batteries can also be used on partially electrified lines, enabling electrification costs to be sharply reduced by missing out those portions of track that are most difficult to electrify (such as bridges or tunnels).

Plans involving hydrogen trains already exist in a number of countries, with at least three companies working to supply them. Germany intends to expand the fleet of hydrogen trains to 14 by 2021 and 5 federal states have signed a letter of intent to purchase 60 trains from Alstom, with 27 ordered as of May 2019 (Schmidt, 2017). Two hydrogen trains that can travel almost 800 km a day on a single refuelling already operate in Lower Saxony in Germany (Alstom, 2018). Austria's Zillertalbahn plans to deploy five hydrogen trains by 2022 for a total investment of almost USD 175 million. The UK government is supporting development of the first hydrogen trains by 2022 (Wiseman, 2019). The French government is similarly considering 2022 as the target for the first hydrogen train to be on the rails. Japan Rail East also has a project underway, in partnership with Toyota (Kyodo ,2018).

Under optimistic assumptions about fuel cell cost reductions, hydrogen trains could become competitive against other passenger services options with low frequency of utilisation

(IEA, 2019b). Hydrogen fuel cell technology is most competitive for services requiring long-distance movement of large trains with low-frequency network utilisation, a common set of conditions in rail freight. The use of hydrogen in rail could be combined with its use for forklifts, trucks and other railyard and logistics hub machinery to decrease costs and improve flexibility.

Aviation

Aviation accounted for almost 2.8% of global energy-related CO_2 emissions in 2017, and air passenger traffic is expected to more than double to almost 16 000 billion km/yr by mid-century under current trends. Efficiency improvements should reduce energy consumption and slow the increase in energy demand, but alternative fuels will eventually be needed to avoid increases in emissions from the sector. Advanced biofuels and hydrogen-based fuels are leading options.

While there have been feasibility studies and demonstration projects testing the scope for using hydrogen in small planes (DLR, 2016; Schilo, 2009; Airbus, 2000), 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 in aircraft design, as well as new refuelling and storage infrastructure at airports. More projects – 130 in total in 2018 – are in development for the direct use of electricity than for pure hydrogen, mostly for urban air taxis (Thomson, 2018). However, direct electrification also faces challenges, specifically relating to battery weight and costs.

In contrast, hydrogen-based liquid fuels would require no changes to design or refuelling infrastructure at airports. Synthetic fuels based on electrolytic hydrogen (so-called power-to-liquid) are estimated to be four to six times more expensive than conventional jet fuel currently (see Chapter 2 for more information on the cost factors underpinning hydrogen-based fuels). Fuel represents a large share of the total costs of operating aircraft so this would significantly increase the operating costs and, presumably, ticket prices.[51] This would be the case regardless of the cost of conventional jet fuel, which could itself become more expensive due to carbon pricing or other policies to reduce emissions. Estimates of the CO_2 price that would be needed to encourage a shift to power-to-liquids in aviation in the long term vary widely, from USD 115/tCO_2 to USD 660/tCO_2, with the lower value accounting for the possible value provided to the wider energy system via the electricity grid (ETC, 2018a; Malins, 2017). Given the lack of other alternatives, most estimates place these costs among the higher abatement costs to complete the transition to a low-carbon energy system.

As with biofuels, the use of hydrogen-based fuels in aviation could be promoted through a target for blend shares. Even a modest target could help to demonstrate feasibility and support the scaling up of production. The standards development organisation, ASTM, currently sets blending limits for alternative fuels that vary by fuel from as low as 10% to up to 90%. These might provide a helpful reference point for public and private decision makers to set upper bounds, and could be updated as new engine technology emerges.

Besides on-board use of hydrogen in aviation, hydrogen is already used today in a few auxiliary power units that generate electricity when the jet engine is not running. Such units, which usually run on natural gas, can account for up to 20% of ground aircraft emissions (Baroutaji et al., 2019).

[51] This could also help to decrease demand through price elasticity or shift between transport modes. It has been estimated that a fourfold increase in fuel prices in Europe could result in almost 60% higher ticket prices and 30% less demand (Murphy et al., 2018).

Hydrogen as a fuel for heat in buildings

The global buildings sector accounts for 30% of global final energy use, nearly three-quarters of which is used for space heating, hot water production and cooking. Including traditional use of solid biomass in developing countries, related energy demand was around 2 200 Mtoe in 2017. Nearly half of this was produced directly from fossil fuels, with natural gas accounting for 620 Mtoe. Most of the rest came from conventional electric equipment (for example electric resistance radiators and cookstoves) and commercial heat (e.g. district heating), around 85% of which was produced using fossil fuels in 2017. Overall, nearly 28% of global energy-related CO_2 emissions result from energy use in buildings.

Replacing heat provision with low-carbon alternatives and reducing heat demand through improving buildings is challenging. Decision-making for energy use in buildings is complex and depends on building type, location, ownership, customer preferences, equipment costs, energy prices and overall convenience, amongst other factors. This plurality of variables means that various energy sources and technologies are likely to co-exist in the future, from natural gas boilers to electric heat pumps, district heating and solar thermal heating. Hydrogen has the potential to contribute to the energy transition (e.g. through blending or methane production) and to long-term strategies for decarbonising heat (e.g. pure hydrogen production from renewables) (Table 6). In doing so, it can make use of existing building and energy network infrastructure to provide both flexibility and continuity.

Table 6. Potential routes to use hydrogen for buildings heat supply

Strategy	Advantages	Requirements	Examples
Blending	Low-cost solution compatible with most existing gas infrastructure and equipment	Blending ratios to around 5–20% in most instances. Additional efficiency measures to further abate CO_2	GRHYD project (2017) in France. HyDeploy (2019) in the United Kingdom
Methane produced from clean hydrogen	Full decarbonisation of gas if low-carbon hydrogen and low-carbon CO_2 inputs. Utilisation of existing gas networks and equipment	Investment in methanation plants. R&D to improve the efficiency of methanation. Carbon source, such as CO_2	STORE&GO (2016) European project with catalytic and biological methanation (demonstration projects between 200 kW and 1 MW)
100% hydrogen	Full decarbonisation of gas if low-carbon hydrogen. Lower efficiency losses than synthetic methane	Investment to upgrade gas network and equipment. Co-ordination between gas suppliers and distributors if various networks coexist	The H21 Leeds City Gate (> 2025) and the H21 Network Innovation Competition (NIC-2018) projects in the United Kingdom
Use of fuel cells and co-generation	Multiple energy services (e.g. heat and electricity). Demand-side response potential	Investment in fuel cell or co-generation technology. R&D to improve the efficiency of equipment	ENE-FARM programme in Japan (2009).* Energy Efficiency Incentive Programme in Germany (2016)**

* Current ENE-FARM installations are running on natural gas or liquefied petroleum gas, mainly targeted at cost reduction.
** The programme includes fuel cell applications in buildings.

How does the buildings sector use hydrogen today?

Hydrogen is very little used as a source of energy in the global buildings sector today, although various potential uses are now being trialled. There are currently 37 demonstration projects examining hydrogen blending in the gas grid (see Chapter 3 for more information). In the United Kingdom, where high heating demands have focused attention on heating solutions, H21 North of England is the largest project and is proposing to supply 100% hydrogen by pipeline to buildings. This project targets hydrogen supply of 180 ktH_2/yr by 2025 and 2 MtH_2/yr by 2035, following studies in 2016 confirming the feasibility of reusing the existing pipeline network (Northern Gas Networks, 2018).

There are in addition micro co-generation and fuel cell hydrogen demonstration projects in Europe and Asia, notably the ENE-FARM project in Japan (Box 14). In Europe, the ene.field demonstration was launched in 2012 and has installed more than 1 000 small stationary fuel cell systems for residential and commercial buildings in 11 countries, with plans to increase this to 2 800 units (Ravn Nielsen and Prag, 2017). In Germany, consumers can access government funding to offset the extra cost for fuel cell appliances in buildings (KfW, 2018). Projects are also being prepared for the demonstration of digital systems to facilitate renewables integration with the storage and supply of electricity and heat in one or multiple buildings, for example in the United Kingdom.

Box 14. The ENE-FARM programme in Japan

ENE-FARM is a large-scale fuel cell demonstration and commercialisation programme aiming to deliver efficient and affordable fuel cell technologies for building applications. The first system was introduced in a residential building in 2009 and close to 300 000 units are expected to be in operation by 2020. The programme aims to install 5.3 million units by 2050. At present ENE-FARM units reform natural gas or liquefied petroleum gas in situ to feed a fuel cell with hydrogen. The use of fossil fuels leads to limited CO_2 reduction benefits, but aids delivery of cost reductions that will help to pave the way for low-carbon hydrogen distribution once it becomes economically attractive. The initial cost per unit has come down by 75% in almost 10 years (from more than USD 35 000 to around USD 9 000 in 2018 (Nagashima, 2018).

Source: Nagashima (2018), Japan's Hydrogen Strategy and Its Economic and Geopolitical Implications.

Potential for future hydrogen demand in buildings

Hydrogen will not make sense for all building applications, and numerous factors will influence eventual hydrogen demand in buildings, including existing natural gas infrastructure, heat densities, other building energy needs and safety considerations. There are barriers related to cost and consumer acceptance, and a variety of policy design challenges, which is why hydrogen use is currently limited to localised operations and larger-scale demonstrators such as those programmes described above. But there are lots of opportunities as well, which are centred around two main options. The first is hydrogen blending in existing natural gas networks. The second is direct use of hydrogen for heat production in buildings. Hydrogen could also be used indirectly to heat or cool local district energy networks that then supply buildings.

These potential applications could be attractive in a wide range of countries where the provision of heat is important and where it is has to be provided in large part to existing buildings. Buildings that are more than 25 years old (and that typically have energy-intensive heating loads) represent around three-quarters of the total buildings stock in the European Union, for example (FCH 2 JU, 2019), while around two-thirds of buildings in the United States and Canada were built before 1990 (OEE, 2018; EIA, 2015; EIA, 2012). Existing buildings, many of them decades old, will continue to represent a sizeable share of the overall buildings stock in the future (Table 7). This means that a certain level of heat demand is already largely "locked in" for several decades to come.

One major advantage of hydrogen blends, direct hydrogen use and indirect hydrogen use for district heating and cooling is that they can make use of existing infrastructure. While technically feasible, other potential solutions would require major new infrastructure, which would inevitably be very costly.

Another major advantage is that hydrogen use in buildings could potentially find synergies with the wider energy system that make it attractive in terms of the overall system cost of low-carbon transitions. Other potential solutions might find this a tougher challenge. For instance, full electrification of heat, even using high-efficiency heat pumps, could lead to large seasonal imbalances in power demand, especially if major building energy efficiency improvements are not delivered in parallel (IEA, 2019c). This would potentially require large-scale peak power or energy storage capacity. Partially or entirely replacing natural gas with biomethane also has limitations: in the European Union, for example, natural gas use for heat in buildings represented around 90 times biomethane production in 2016 (EBA, 2017). Global biogas production would need to increase 20-fold to meet current natural gas demand in the buildings sector.

Table 7. The global buildings stock and share of gas in heat production in 2017

Region	Floor area (billion m^2)	Heat demand per capita, MWh	Share of natural gas in heat	Estimated share of existing buildings in 2050 stock
North America*	37	7.6	61%	55%
European Union*	29	7.2	43%	57%
Other advanced economies*	13	4.9	33%	53%
Russia*	5	10.7	35%	55%
China*	58	2.2	17%	50%
India	21	0.4	4%	17%
Africa	21	0.3	10%	18%
Latin America	12	1.0	27%	32%
Other emerging economies*	39	1.2	44%	31%
World	**235**	**2.4**	**41%**	**39%**

* Indicates markets with major heating demand as a share of total final energy consumption in the buildings sector. Russia = the Russian Federation; China = the People's Republic of China.

Notes: m^2 = square metre. Excludes traditional use of solid biomass and does not include natural gas use in production of commercial heat.

Source: IEA 2019. All rights reserved.

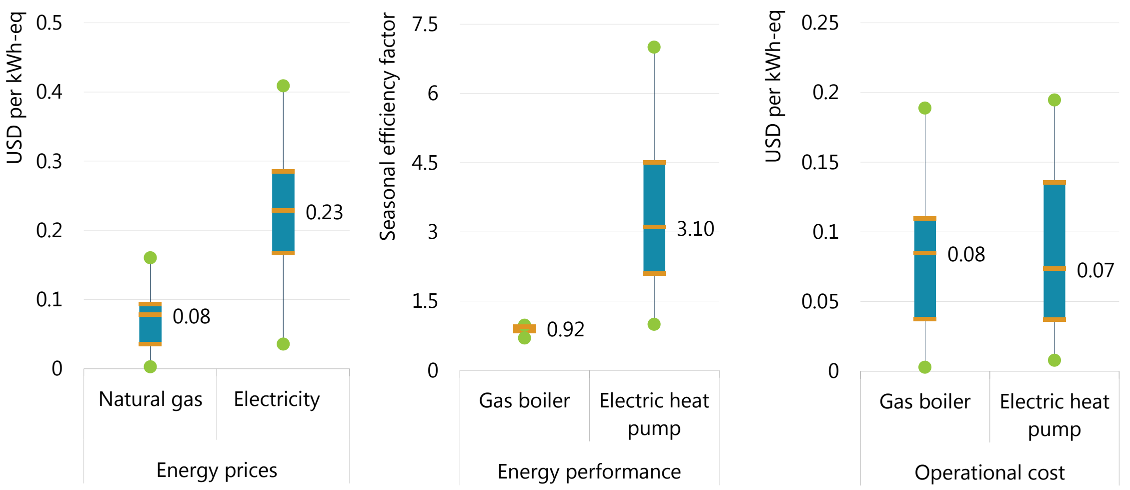
Blending hydrogen into natural gas for heating

In major heating markets like Canada, the United States and Western Europe, blending low shares of hydrogen – 3–5% hydrogen by volume – into supplied natural gas would have little impact on end-use equipment such as boilers and gas cookstoves. As described in Chapter 3, 20% blend shares in 14 buildings in Ameland (the Netherlands) found no problems with leakage, flame stability, back firing or ignition, nor were there problems with pipes or heating equipment at 30%. Other projects around the world have tested specific pieces of equipment, with similar conclusions.

Rigorous testing to ensure system safety, efficiency and environmental performance in the long run would nonetheless be required as the general tolerance of domestic appliances at higher blends cannot be assumed, especially for older equipment. In parallel, it would make sense to ensure that any infrastructure or equipment upgrades were compatible with a possible switch to higher shares of hydrogen.

Blending hydrogen can create dependable demand for hydrogen through its early deployment phase, but managing the cost impacts is a key challenge for policy makers. Taking an illustrative example, if hydrogen were blended into all natural gas use around the world at just 3% by volume, this would boost clean hydrogen demand by close to 12 MtH_2/yr. This would be a significant scale-up of hydrogen supply, equivalent to about 17% of current global dedicated hydrogen production. This could potentially have a major impact on the costs of hydrogen supply technologies through expansion of manufacturing and installation, but would add around 3–15% to natural gas supply costs. Many markets are currently close to the tipping point between gas and electricity prices that could trigger a switch to higher-performance heat pump technologies – including hybrid or gas thermal heat pumps – where they are appropriate, especially for new construction (Figure 59). Increases in gas prices resulting from blending mandates or incentives would risk losing gas customers, something to be considered in policy design.

Figure 59. Spread of energy prices, performance and operational costs for gas and electric heating equipment in IEA countries, 2017



Notes: kWh-eq = kilowatt hour equivalent. Prices are residential prices, including taxes, in USD 2017 using purchasing power parities.
Source: IEA 2019. All rights reserved.

Relative gas and electricity prices are finely poised in many countries between levels that would make heat pumps or gas boilers the most cost-effective for new installations.

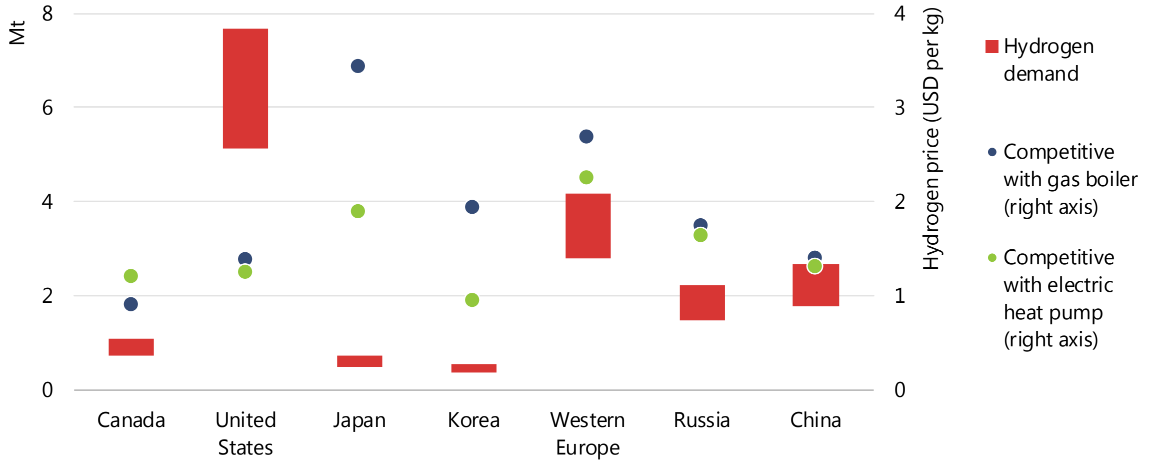
Shares higher than 20% hydrogen in the natural gas network could be achieved through hydrogen-based fuels. However, injecting synthetic methane, which would avoid the need to replace existing equipment in most instances, would likely raise gas prices much higher than pure hydrogen blends per unit of energy delivered.

100% hydrogen use for heating

From the perspective of costs, 100% hydrogen use in buildings (e.g. via a fuel cell or hydrogen boiler) appears most attractive for relatively large commercial buildings or building complexes, and for district energy networks. Fuel cells, co-generation units or other hybrid systems could be used in such cases with energy storage capacity (provided by thermal storage or via a district energy network) to meet heating, cooling and electricity demand, taking advantage of on-site renewables or low electricity prices. Fuel cell and co-generation technologies could equally be used in district energy networks, which when paired with storage (either thermal or hydrogen) could improve power system balancing across the year, avoiding large seasonal peaks and enabling greater flexibility in the grid. Paired with large-scale heat pumps, those district energy solutions could also dramatically increase the overall efficiency of heat production for buildings.

For the broader buildings market, particularly for residential housing, the prospects for hydrogen conversion in the longer term will depend on several critical factors, notably hydrogen price and technology cost. Prices of hydrogen delivered to consumers would likely need to be in the range of USD 1.5–3.0/kgH_2 in many major heating markets for hydrogen to compete with natural gas boilers and electric heat pumps (Figure 60).[52] Higher final prices in the range of USD 3–4/kgH_2 might still be competitive with natural gas prices in some countries or for some building types (and eventual CO_2 pricing would narrow that spread), while in other countries with low gas prices, such as Canada, prices would probably need to be below USD 1/kgH_2.

Figure 60. Potential hydrogen demand for heating in buildings and spread of competitive energy prices in selected markets, 2030



Notes: Prices are average retail prices, including taxes, in USD 2017. Natural gas demand is for space heating and hot water production and includes building envelope improvements to 2030 under a Paris-compatible pathway. Competitiveness of electric heat pumps assumes a typical seasonal efficiency of the heat pump in those countries. Price competitiveness does not include capital costs of the equipment.

Source: IEA 2019. All rights reserved.

Final energy prices for hydrogen are likely to have to be in the range USD 1.5–3.0/kgH_2 in major heating markets in order to compete with natural gas and electricity in providing heat in buildings.

[52] This also depends on the type of heat pump, its efficiency in the prevailing climate and the building's energy performance.

It will not necessarily be enough for a product to offer lower running costs over time if it is more expensive at the outset. Consumers often give more weight to upfront purchase prices than to overall lifetime costs. Heating equipment costs vary substantially depending on factors such as unit capacity, brand, availability in local markets and overall size of product demand. In addition, consumer preference will also matter on issues such as safety and ease of installation. Moreover some types of building will be better suited to the use of hydrogen than others. Large-scale co-generation, for example, may be more cost-effective in terms of both capital and operational expenditure for large commercial buildings than for small-scale residential ones. Similarly, large-scale fuel cell co-generation may be well-suited to the supply of renewable electricity to buildings adapted with high-performance heat pumps and clean district heat (as a replacement for hard-to-convert gas-based systems), but less well-suited to other types of buildings.

If 100% hydrogen is ultimately able to compete in terms of capital and operational costs in some markets, the market potential in buildings is very large indeed. Heat demand will inevitably remain central to energy demand in buildings, even in a low-carbon context. In a Paris-compatible pathway, heat demand would be expected to represent more than half of global building energy consumption in 2030, with about 500 Mtoe of natural gas used for space and water heating in buildings annually. Of this, theoretical potential hydrogen demand might be on the order of 12–20 MtH_2/yr in key markets (Canada, the United States, Western Europe, Japan, Korea, the Russian Federation ["Russia"] and China) if all gas boiler equipment installed or replaced at expected stock turnover rates between today and 2030 were hydrogen-ready (Table 8). Combining this with low-concentration hydrogen blends in the wider natural gas grid gives an upper bound of 14– 24 MtH_2 global hydrogen demand in 2030.

Table 8. 2030 natural gas demand for heat in buildings and indicative theoretical hydrogen demand in selected regions

Region	Natural gas demand (Mtoe)	Competitive price range for hydrogen (USD/kgH_2)	Indicative hydrogen demand (MtH_2)
Canada	21	0.8–1.2	0.7–1.1
United States	147	1.2–1.5	5.1–7.7
Western Europe	80	2.0–3.0	0.5–0.7
Japan	14	2.0–3.5	0.4–0.6
Korea	11	0.9–1.9	2.8–4.2
Russia	43	1.5–1.8	1.5–2.2
China	51	1.2–1.4	1.8–2.7

Notes: Natural gas demand is for space heating and hot water production and takes account of building envelope improvements under a Paris-compatible pathway. Indicative demand assumes that hydrogen production, transmission and distribution is within the competitive range shown here and does not include potential hydrogen demand for hydrogen-based fuels. Excludes natural gas use in production of commercial heat. Western Europe includes France, Germany, Italy and the United Kingdom. Indicative of direct hydrogen use in buildings. The indicative demand takes into account typical lifetimes of existing heating equipment in buildings and does not assume early retirement of equipment.

Source: IEA 2019. All rights reserved.

Achieving these levels of hydrogen use in buildings, and potentially higher levels in the longer term, faces several barriers. These include higher upfront capital costs and higher energy prices for consumers, as well as any safety concerns that consumers may have. In the near term, demonstration projects with strong public and private participation can continue to help identify and find ways of overcoming these barriers, especially if they provide practical information based on:

- Urban development patterns. For example, most current demonstration projects are not located in the types of urban areas where most heat demand is and which are generally more challenging to supply with hydrogen. Similarly, demonstration buildings are often single-occupancy or low-density commercial or multifamily residential units that do not illustrate the practical application of hydrogen equipment in dense urban environments or in older buildings where electric or hybrid electric-natural gas heat pumps may be less appropriate, making them a key target opportunity for hydrogen.
- Building types. Large-scale co-generation, for instance, may be more cost-effective in terms of both CAPEX and OPEX for large commercial buildings than for small-scale residential ones. Large-scale fuel cell co-generation may also be well-suited to the supply of renewable electricity to buildings equipped with high-performance heat pumps and clean district heat (as a replacement for hard-to-convert gas-based systems), but less suited to other types of buildings.

Realising the potential for hydrogen use in buildings and moving to the use of low-carbon hydrogen will require co-ordination between policy makers, industry and investors, as well as greater engagement with consumers and with the equipment service sector. Installers, for example, may require training or specific skills. Governments can help to facilitate dialogue and remove potential obstacles to the use of hydrogen by measures such as improving policy regulations; providing clear signals about their expectations for the future carbon intensity of heat (including ambitious targets to decarbonise natural gas networks); continuing to improve the evidence base on hydrogen applications for heat in buildings; and supporting innovation.

Hydrogen for power generation and electricity storage

Hydrogen plays a negligible role in the power sector today: it accounts for less than 0.2% of electricity generation. This is linked mostly to the use of gases from the steel industry, petrochemical plants and refineries. But there is potential for this to change in the future. Co-firing of ammonia could reduce the carbon intensity of existing conventional coal power plants, and hydrogen-fired gas turbines and combined-cycle gas turbines could be a source of flexibility in electricity systems with increasing shares of variable renewables. In the form of compressed gas, ammonia or synthetic methane, hydrogen could also become a long-term storage option to balance seasonal variations in electricity demand or generation from renewables (Table 9).

Table 9. Role of hydrogen and hydrogen-based products in power generation

	Current role	Demand perspectives	Future deployment	
			Opportunities	**Challenges**
Co-firing ammonia in coal power plants	No deployment so far; co-firing has been demonstrated in a commercial coal power plant in Japan	20% co-firing share in global coal power plant fleet could by 2030 lead to an ammonia demand of up to 670 Mt ammonia or a corresponding hydrogen demand of 120 MtH_2	Reducing the carbon impact of existing coal-fired power plants in the near term	CO_2 mitigation costs can be low, but rely on low-cost ammonia supply. Attention has to be paid to NO_x emissions; further NO_x treatment may be needed. Only a transitional measure – still significant remaining CO_2 emissions
Flexible power generation	Few commercial gas turbines using hydrogen-rich gases. 363 000 fuel cell units (1 600 MW) installed	Assuming 1% of global gas-fired power capacity would run on hydrogen by 2030, this would result in a capacity of 25 GW, generating 90 TWh of electricity and consuming 4.5 MtH_2	Supporting the integration of VRE in the power system. Some gas turbine designs already able to run on high hydrogen shares	Availability of low-cost and low-carbon hydrogen and ammonia. Competition with other flexible generation options as well as other flexibility options (e.g. demand response, storage)
Back-up and off-grid power supply	Demonstration projects for electrification of villages. Fuel cell systems in combination with storage	With increasing growth of telecommunications, also growing need for reliable power supply	Fuel cell systems in combination with storage as a cost-effective and less polluting alternative to diesel generators. More robust than battery systems	Often higher initial investment needs compared with diesel generators
Long-term and large-scale energy storage	Three salt cavern storage sites for hydrogen in the United States; another three in the United Kingdom	In the long term, with very high VRE shares, need for large-scale and long-term storage for seasonal imbalances or longer periods with no VRE generation. In combination with long-distance trade, scope to take advantage of seasonal differences in global VRE supply	Due to high energy content of hydrogen, relatively low CAPEX cost for storage itself. Few alternative technologies for long-term and large-scale storage. Conversion losses can be reduced if stored hydrogen or ammonia can be directly used in end-use applications	High conversion losses. Geological availability of salt caverns for hydrogen storage region-specific. Little experience with depleted oil and gas fields or water aquifers for hydrogen storage (e.g. contamination issues)

Note: VRE = variable renewable energy.

How does the power sector use hydrogen today?

Although pure hydrogen does not generally feature as a fuel in power generation today, there are small-scale exceptions. For example, a 12 MW hydrogen-fired combined-cycle gas turbine in Italy uses hydrogen from a nearby petrochemical complex, while in Kobe, Japan, a hydrogen-fired gas turbine is providing heat (2.8 watts thermal) and electricity (1.1 MW_e) to a local community. Somewhat more common is the use of hydrogen-rich gases from steel mills, petrochemical plants and refineries. Reciprocating gas engines today can handle gases with a hydrogen content of up to 70% (on a volumetric basis),[53] while in the future gas engines should be able to operate on even 100% hydrogen (Goldmeer, 2018). Gas turbines also have the capability to run on hydrogen-rich gases. In Korea a 40 MW gas turbine at a refinery has run on gases with a hydrogen content of up to 95% for 20 years.

Fuel cells are a further option to convert hydrogen into electricity and heat, producing water and no direct emissions. They can achieve high electric efficiencies of over 60% and reveal a higher efficiency in part load than full load, which makes them particularly attractive for flexible operations such as load balancing (Box 15).

Box 15. Fuel cell technologies for stationary power applications

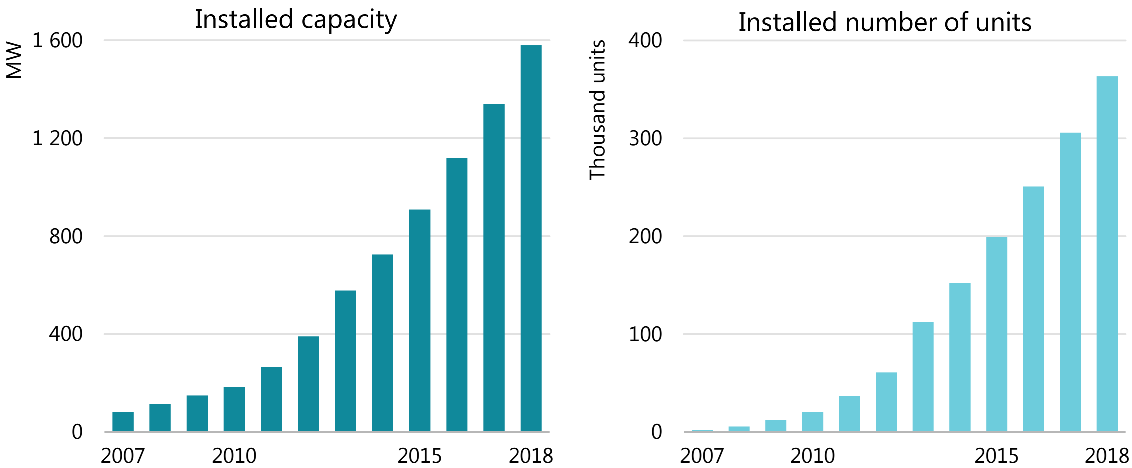
Various fuel cell technologies exist for stationary power applications:

- **Polymer electrolyte membrane fuel cells (PEMFCs)** operate at relatively low temperatures (below 100°C) and have a quick start-up time. They require, however, a pure hydrogen stream, or an external reformer if natural gas is used as fuel. PEMFCs are used today as micro co-generation units, operating with natural gas or LPG in residential buildings.
- **Phosphoric acid fuel cells (PAFCs)**, based on phosphoric acid as electrolyte, are used today as stationary power generators with outputs in the 100–400 kW range. In addition to electricity, they also produce heat at around 180°C, with potential uses for space and water heating.
- **Molten carbonate fuel cells (MCFCs) and solid oxide fuel cells (SOFCs)** operate at higher temperatures, 600°C and 800–1 000°C respectively, which allow them to run on different hydrocarbon fuels without the need for an external reformer to produce hydrogen first. MCFCs are used in the MW scale for power generation (due their low power density, resulting in a relatively large size). The produced heat can be used for heating or cooling purposes in buildings and industrial applications. SOFCs have similar application areas, often at smaller scale in the kW range, such as micro co-generation units or for off-grid power supply.

[53] Hydrogen has a more than one third lower energy content per cubic metre (m3) of 10 MJ/m^3 compared to natural gas with 35 MJ/m^3. Therefore, a volumetric blending share of 70% of hydrogen into natural gas corresponds to a 20% blending share in energy terms. If not noted otherwise, the hydrogen shares in this section refer to volumetric shares.

Global installed stationary fuel cell capacity has been rapidly growing over the last ten years, reaching almost 1.6 GW in 2018 (Figure 61), although only around 70 MW uses hydrogen as fuel; most of the existing fuel cells today run on natural gas. The number of globally installed fuel cell units is around 363 000, largely dominated by micro co-generation systems. The Japanese ENE-FARM initiative (Box 14) accounts for the majority, with around 276 000 micro co-generation systems, but represents only 12% of the installed capacity at 193 MW (IPHE, 2018a). Outside Japan, the residential fuel cell market is also growing in Germany, driven by the KfW433 support programme with around 1 900 funding approvals by November 2018 (IPHE, 2018b). Larger fuel cell systems above 100 kW to 2.4 MW are still almost exclusively deployed in Korea and the United States, with installed capacities of 300 MW and 150 MW, respectively. A further growing market for fuel cells is the provision of back-up power and off-grid electricity (Box 16).

Figure 61. Development of global stationary fuel cell capacity, 2007–18



Sources: E4tech (various years), *The Fuel Cell Industry Review*; S&P Global Platts (2018), *World Electric Power Plants Database*.

Stationary fuel cells have experienced strong growth over the last decade in terms of installed capacity and number of units, but still represent only 0.02% of global power generation capacity.

Very few countries have stated explicit targets for the use of hydrogen or hydrogen-based fuels in the power sector. Japan is one of the few exceptions: it aims to reach 1 GW of power capacity based on hydrogen by 2030, corresponding to an annual hydrogen consumption of 0.3 MtH_2, rising to 15–30 GW in the longer term, corresponding to annual hydrogen use of 15–30 MtH_2 (METI, 2017). Korea is another exception: its hydrogen roadmap sets a target of 1.5 GW installed fuel cell capacity in the power sector by 2022, and 15 GW by 2040. A number of countries have, however, recognised the potential of hydrogen as a low-carbon option for power and heat generation.

Research and pilot projects to introduce hydrogen and ammonia as fuel for gas turbines and coal power plants are being pursued in Japan. An existing 440 MW combined-cycle gas turbine (CCGT) plant is being converted from natural gas to hydrogen in the Netherlands, and ammonia is being considered for long-term storage there; it would be reconverted into hydrogen and nitrogen before combustion of the hydrogen in the gas turbine (Northern Netherlands Innovation Board, 2017). The Port Lincoln Green Hydrogen Project under construction in Australia includes a 30 MW electrolyser plant and an ammonia production facility, as well as a 10 MW hydrogen-fired gas turbine and a 5 MW hydrogen fuel cell, which will supply balancing services to the grid and the ammonia plant. The facility will also support to two new solar farms, as well as a nearby micro-grid which will be utilised by local aqua agriculturists who have been affected by ageing back-up power generation (Bruce et al., 2018).

Box 16. Using fuel cells to provide back-up power and access to electricity

The provision of back-up power and off-grid electricity is today often still dominated by diesel generators. Fuel cells represent a possible alternative, in many cases reducing local air pollution as well as the need for imported diesel. An estimated 2 500 to 3 000 such systems were deployed in 2018 (E4Tech, 2018).

The mobile telecommunication industry is an example of a sector that needs back-up and off-grid power. It relies on an estimated 7 million base stations worldwide, and this number is increasing by over 100 000 each year, mostly in developing and emerging economies. To ensure reliable electricity supply for these base stations in parts of the world where the electricity infrastructure is weak or no grid connection is available, these base stations require their own electricity supply, which is often provided by diesel generators or diesel-battery hybrid systems, with each base station consuming around 10 000 to 12 000 litres of diesel per year. To take one example, India has around 650 000 telecom towers today, around 20% of which rely on diesel generators, resulting in an annual diesel consumption of 5 billion litres and CO_2 emissions of 5 $MtCO_2$/yr (Lele, 2019).

Fuel cell systems, relying on bottled hydrogen, methanol or ammonia as fuel, offer an alternative to diesel generators or battery systems. Compared to battery systems, fuel cells can operate in environments from -40°C to 50°C without the need for any cooling. (It has been also reported that compared to diesel generators, PV systems and batteries, fuel cells and their fuel appear less attractive to thieves.) In Kenya 800 base stations are switching from diesel generators to 4 kW ammonia-based alkaline fuel cell systems, including a cracker to convert the ammonia into hydrogen. A single 12-tonne tank of ammonia can provide enough fuel to operate a base station for a year (Ammonia Energy, 2018). In South Africa, over 300 stationary fuel cell systems have been rolled out by Vodacom to provide back-up power for telecom base stations, with a further 250 planned for 2019.

Fuel cells can also help to provide back-up for power outages and access to electricity for off-grid villages, schools and clinics. In South Africa, a small rural village of 34 households was electrified in 2014 in a trial project through a mini grid, relying for electricity supply on three 5 kW methanol fuel cells in combination with a 14 m^3 methanol tank and a 73 kWh battery bank. Improvements to stationary fuel cell systems have led to larger field trials, with more recent deployments in Kwa Zulu Natal province involving energy provision for over 500 households in two rural villages as well as water distribution in the area. In 2015 a fuel cell system was installed at a clinic in Gauteng province to provide back-up power for refrigeration of critical medicines and vaccines during power outages. In the same year, in the Eastern Cape province of South Africa, hydrogen fuel cells were installed at schools to support basic electricity requirements such as charging stations for tablets, fax machines and computers.

A wider market for stationary power installations up to around 5 MW for uninterruptible and back-up power is also growing, for example in California, reflecting the importance of uninterrupted power for data centres, banks, hospitals and similar organisations. This provides another potential route for fuel cells to scale up, in particular SOFCs. They can be manufactured with electronics industry techniques, and installed quickly and on a modular basis in densely populated areas. They run quietly without NO_x emissions and provide resilience against power grid outages by using the natural gas grid, thus avoiding the need for on-site fuel storage. The modular nature of fuel cells means that they lend themselves to real-time monitoring and servicing of components without downtime, which fits well with the trend towards more digitalisation in operations and branding. To reduce emissions they could switch to be run on hydrogen in the future or fitted with CO_2 capture if a system for collecting the CO_2 were available, for example for geological storage.

Sources: E4Tech (2018), *The Fuel Cell Industry Review*; Lele (2019), "Hydrogen and fuel cells at Reliance Industries Limited"; Ammonia Energy (2018), "GenCell launches commercial alkaline fuel cell using cracked ammonia fuel".

Potential for future hydrogen demand in the power sector

Hydrogen and hydrogen-based fuels such as ammonia and synthetic natural gas can be fuels for power generation. Ammonia can be co-fired in coal-fired power plants to reduce coal usage and reduce the carbon footprint of these plants; if low carbon, it would also reduce overall emissions. Hydrogen and ammonia can also be used as fuels in gas turbines, CCGTs or fuel cells, thus providing a flexible and potentially low-carbon generation option. Hydrogen-based fuels are also options for large-scale and long-term energy storage to balance seasonal variations in electricity demand or variable renewable power generation.

Co-firing of ammonia in coal power plants

In 2017 the Japanese Chugoku Electric Power Corporation successfully demonstrated the co-firing of ammonia and coal, with a 1% share of ammonia (in terms of total energy content) at one of their commercial coal power stations (120 MW) (Muraki, 2018). Using ammonia as fuel raises concerns about an increase in NO_x emissions, but the demonstration managed to keep them within the usual limits and to avoid any ammonia slip into exhaust gas. Higher blending shares of up to 20% ammonia in energy terms might be feasible with only minor adjustments to a coal power plant. In smaller furnaces with a capacity of 10 MW thermal, blending shares of 20% ammonia have been achieved without problems, and in particular without any slippage of ammonia into exhaust gas.

The economics of substituting coal with ammonia depend on the availability of low-cost ammonia (Chapter 2), but ammonia could help to reduce emissions if produced from low-carbon hydrogen. By 2030 around 1 250 GW of coal power plants worldwide that are currently in operation or under construction could not only still be in service, but could also still have a remaining lifetime of at least 20 years. Co-firing with a 20% share of ammonia could reduce the 6 $GtCO_2$/yr annual emissions of these coal plants by 1.2 $GtCO_2$, provided that the ammonia was produced from low-carbon hydrogen. Reaching a 20% blending share would result in an annual ammonia demand of 670 Mt, more than three times today's global ammonia production, which in turn would require 120 MtH_2.

Flexible power generation

Hydrogen can be used as a fuel in gas turbines and CCGTs. Most existing gas turbine designs can already handle a hydrogen share of 3–5% and some can handle shares of 30% or higher. The industry is confident that it will be able to provide standard turbines that are able to run entirely on hydrogen by 2030 (EUTurbines, 2019).

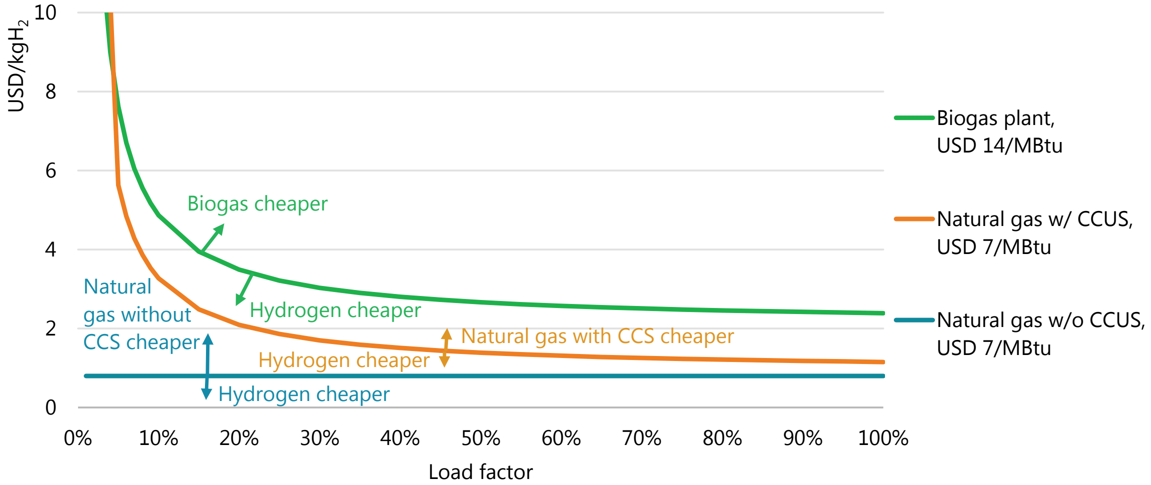
Ammonia is another potential fuel for gas turbines. The direct use of ammonia has been successfully demonstrated in micro gas turbines with a power capacity of up to 300 kW (Shiozawa, 2019). In larger gas turbines above 2 MW, the slow reaction kinetics of ammonia with air, the flame stability and the NO_x emissions are issues still being investigated by researchers (Valera-Medina et al., 2018). Instead of directly burning ammonia, an alternative approach is to reconvert the ammonia first into hydrogen and nitrogen, to burn hydrogen in the combustor of the gas turbine. The heat required for decomposing (or cracking) the ammonia at temperature levels of 600–1 000°C (the temperature depends on the catalyst) can be supplied by the gas turbine, though this slightly reduces the electricity generation efficiency of the overall process.

Fuel cells can also be used as a flexible power generation technology. With electric efficiencies of 50–60% (lower range today, upper future potential) being in a similar range to those of CCGTs, the choice between fuel cells and CCGTs in economic terms largely depends on their capital costs. It is, however, worth noting that fuel cell stacks today still suffer from a shorter technical lifetime than gas turbines (10 000 to 40 000 hours of operation), and that stationary fuel cells today typically have a smaller power output (up to 50 MW for the largest fuel cell power plants), which makes them most suitable for distributed generation. For comparison, CCGT units can reach capacities of 400 MW. The heat produced by the fuel cell while generating power can be used to provide an additional revenue stream. Future cost reductions for fuel cells will depend on future deployment levels and the learning effects and economies of scale that follow from this. On optimistic assumptions, CAPEX for hydrogen fuel cells may fall to USD 425/kW by 2030 compared to USD 1 600/kW for a 1 MW PEMFC unit today or USD 1 000/kW for a CCGT today (Bruce et al., 2018).

Hydrogen and ammonia could offer low-carbon flexibility for electricity systems with increasing shares of VRE. Alternative low-carbon flexible generation options are natural gas-fired power plants equipped with CCUS and biogas power plants. Both alternatives are characterised by higher capital costs per unit of power than needed for a hydrogen-fired CCGT power plant, due to the additional capture equipment needed for CCUS and the typically smaller scale of biogas power plants. The capital cost advantage of the hydrogen option is more pronounced when the load factor is low (Figure 62), and it often is low in systems with high shares of VRE. At a capacity factor of 15%, low-carbon hydrogen would become competitive with electricity generation from natural gas with CCS at hydrogen prices of USD 2.5/kgH_2, if the gas price is USD 7/MBtu.[54]

[54] For comparison, USD 1/kgH_2 corresponds to USD 8.8/MBtu.

Figure 62. Break even for hydrogen CCGT against other flexible power generation options



Notes: Arrows indicate areas where hydrogen costs and load factors mean that competing generation technologies or hydrogen are cheaper. CAPEX = USD 1 000/kW for CCGT without CCS and hydrogen-fired CCGT, USD 1 870/kW for CCGT with CCS, USD 2 000/kW for biogas engine; gross efficiencies (LHV) = 61% CCGT without CCS and hydrogen-fired CCGT, 53% CCGT with CCS, 45% biogas engine. Economic lifetime = 25 years. More information on the assumptions is available at www.iea.org/hydrogen2019.

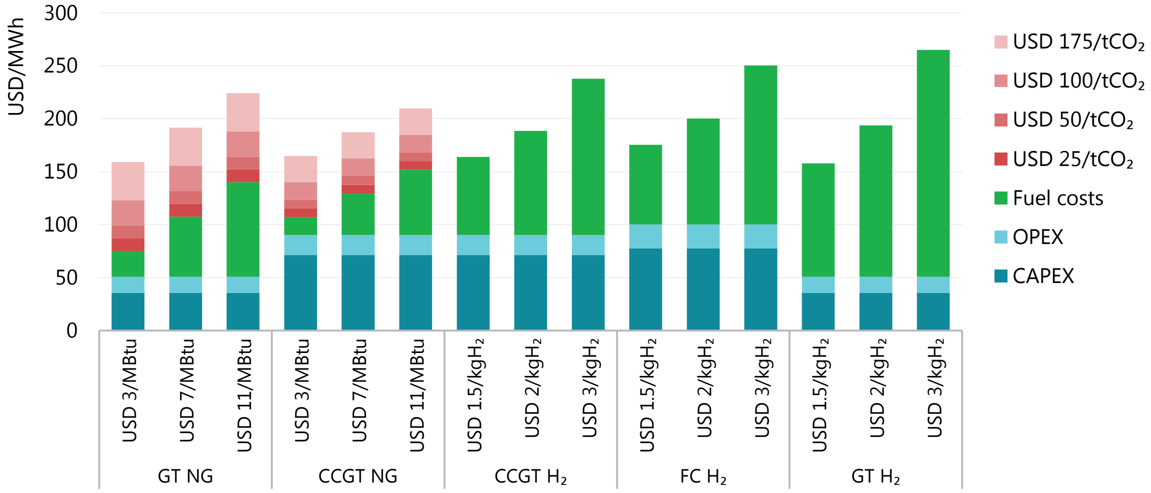
Source: IEA 2019. All rights reserved.

Hydrogen may be cost-competitive with natural gas with CCS and biogas as a flexible generation option, particularly at low load factors.

The competitiveness of hydrogen-fired power plants with natural gas-fired power generation for load balancing and peak load generation depends on the gas price and the potential level of carbon prices. Looking, for example, at a load factor of 15% and a natural gas price of USD 7/MBtu, the CO2 price would have to be USD 100/tCO2 to make hydrogen-fired power generation at a hydrogen price of USD 1.5/kgH2 competitive with natural gas. If the hydrogen price was USD 2/kg H2, the CO2 price would have to be USD 175/tCO2 to make electricity from hydrogen competitive against natural gas (Figure 63).

For illustrative purposes, if 1% of the globally installed gas-fired power capacity (or 25 GW) was fired by hydrogen (or ammonia) in 2030, this would result in annual electricity generation of around 90 TWh (40% load factor) and hydrogen demand of 4.5 MtH_2 (or 30 Mt of ammonia). This would help to scale up demand and the supply infrastructure for hydrogen, since the annual hydrogen demand of 25 GW of hydrogen power plants would correspond to the annual consumption of around 23 million fuel cell vehicles. Even a single 500 MW power plant would create a hydrogen demand equivalent to 455 000 fuel cell vehicles or the heat demand of 221 000 homes in the United Kingdom, and might therefore provide an opportunity to create a hub for other potential hydrogen users, such as transport or buildings.

Figure 63. Levelised electricity generation costs for load balancing from natural gas and hydrogen



Notes: GT = gas turbine; CCGT = combined-cycle gas turbine; FC = fuel cell; NG = natural gas. CAPEX = USD 500/kW GT, USD 1 000/kW CCGT without CCS and hydrogen-fired CCGT, USD 1 000/kW FC. Gross efficiencies (LHV) = 42% GT, 61% CCGT without CCS and hydrogen-fired CCGT, 55% FC. Economic lifetime = 25 years for GT and CCGT, 20 years for FC. Capacity factor = 15%. More information on the assumptions is available at www.iea.org/hydrogen2019.

Source: IEA 2019. All rights reserved.

Whether hydrogen-based power generation for load balancing can compete on price against natural gas depends on regional hydrogen, natural gas and CO2 prices.

Large-scale and long-term storage

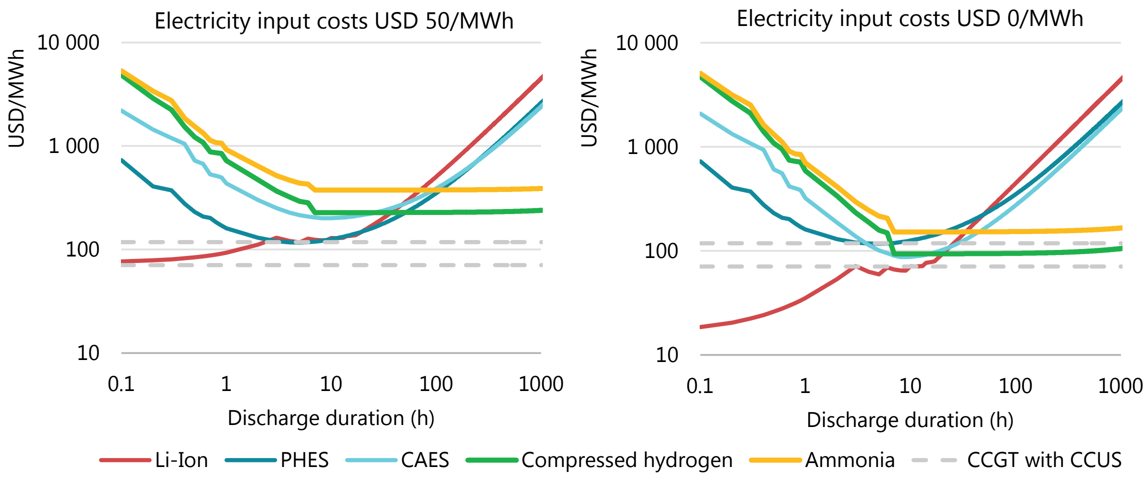
The integration of increasing shares of VRE sources in the electricity system requires a more flexible electricity system. High shares of renewables can create a need for long-term and seasonal storage, for example to provide electricity during periods of several days with very little wind and or sunshine.

Hydrogen and hydrogen-based fuels (such as methane, liquid organic hydrogen carriers [LOHCs] and ammonia produced from electricity via electrolysis) are potential options for long-term and large-scale storage of energy. Salt caverns are the best choice for the underground storage of pure hydrogen because of their tightness and low risk of contamination. Alternative underground hydrogen storage options such as pore storage and storage in depleted oil and gas fields are also being investigated. Converting electricity into methane via power-to-gas is a further long-term storage option, and one which could take advantage of the existing transport and storage infrastructure for natural gas. Around 70 power-to-gas projects to produce methane are in operation today, most of them in Europe (Chapter 2). Storing electricity in the form of ammonia is another long-term and large-scale storage option. Large steel tanks are already commonly used in the fertiliser industry for storing ammonia.

Hydrogen-based storage options suffer from low round-trip efficiency: in the process of converting electricity through electrolysis into hydrogen and then hydrogen back into electricity, around 60% of the original electricity is lost, whereas for a lithium-ion battery the losses of a storage cycle are around 15% (Figure 64). Pumped-hydro storage facilities offer one alternative: they have been used for more than a century to store electricity for relatively long periods. Batteries offer another alternative, although they are unlikely to be used for long-term and large-scale storage because they suffer from self-discharge and because of the immense number of batteries that would be needed for large-scale storage. A single large refrigerated liquid ammonia tank with a diameter of 50 metres and a height of 30 metres, as typically used in the fertiliser industry, can store energy amounting to 150 GWh, comparable to the annual electricity consumption of a city with a population of 100 000. To store the same amount of electricity with batteries would require around 1 150 times the installation of the Australian Hornsdale Battery Reserve, the largest lithium-ion battery storage today in the world with a capacity of 129 MWh.

All the alternatives have advantages and disadvantages. For shorter discharge durations below a few hours, hydrogen and ammonia are much more expensive than pumped-hydro storage or battery storage. With longer discharge durations, compressed hydrogen and ammonia become more attractive, benefitting from their relative low capital costs for energy storage volumes (the investment costs to develop underground salt caverns or storage tanks). Among the different storage technologies considered here, compressed hydrogen becomes the most economic option for discharge durations beyond 20–45 hours.

Figure 64. Levelised costs of storage as a function of discharge duration



Notes: PHES = pumped-hydro energy storage; CAES = compressed air energy storage; Li-Ion = lithium-ion battery. Compressed hydrogen storage refers to compressed gaseous storage in salt caverns, ammonia storage to storage in tanks.

Source: IEA 2019. All rights reserved.

Depending on the costs of the stored electricity, compressed hydrogen storage becomes the most economic storage option at discharge durations longer than 20–45 hours.

Hydrogen as an electricity storage option could also be combined with other uses of hydrogen in the interests of competitiveness. In the United States, for example, the Three-State Generation and Transmission utility is considering producing ammonia from electricity for the domestic fertiliser market. Situated in an area with low-cost electricity from wind, solar and hydropower, the project would use a reversible solid oxide electrolyser cell (rSOEC) to produce hydrogen when the cost of electricity is less than USD 25/MWh (which is 85% of the time), turning it into ammonia for sale on the market, while storing some of it for electricity generation in the rSOEC during peak hours, thus improving its overall utilisation rate. This approach may be an alternative to installing new electric generation resources that are expected only to be needed during peak load times.

It may not be necessary to use large-scale storage of hydrogen-based fuels to cover the full storage cycle, i.e. taking electricity as input and converting it in the end back into electricity.

Instead of filling long-term storage with hydrogen from domestic electricity, hydrogen-based fuels can also be imported from other parts of the world with seasonal surpluses of renewable electricity generation at that time, taking advantage of complementary seasonal patterns of renewable electricity supply and electricity demand. Depending on the frequency and scale of the imports, this could reduce the storage volumes needed in the importing region. The conversion back to electricity may also not always be needed. Stored methane, ammonia or hydrogen could be directly used as fuel to cover seasonal demands, such as for space heating.

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Chapter 6: Policies to boost momentum in key value chains

- **Hydrogen is already widely used in some industries, but it has not yet realised its potential to support clean energy transitions.** Hydrogen can be produced from many sources and it could play a very important and versatile part in a clean energy future. There have been numerous successful government-backed projects in recent years; now it is time for policy to help stimulate commercial demand for cleaner hydrogen and for proponents to demonstrate they can build on the current unprecedented momentum.

- **Ambitious, pragmatic and near-term action is needed to further overcome barriers and reduce costs**. The 2030 time horizon will be crucial for the wider deployment of hydrogen in the longer term. There is scope to build on hydrogen's current uses by scaling up low-carbon production and fostering innovation. In parallel, demand for hydrogen in new sectors and applications can be created and markets connected.

- **Five smart policy actions are needed to 2030:** (1) establish long-term signals to foster investor confidence; (2) stimulate commercial demand for hydrogen in multiple applications; (3) help mitigate salient risks, such as value chain complexity; (4) promote R&D and knowledge sharing; and (5) harmonise standards and remove barriers.

- **Four value chains offer springboard opportunities** to scale up hydrogen supply and demand, building on existing industries, infrastructure and policies:

- **Make industrial clusters the nerve centres for scaling up the use of clean hydrogen.** Growing hydrogen demand in major industries offers the opportunity to create hubs that bring down the cost of low-carbon hydrogen pathways and kick-start new sources of demand. Coastal industrial clusters, co-located near ports, are particularly attractive,

- **Use existing gas infrastructure to help boost low-carbon hydrogen supply and make the most of a reliable source of demand.** Even 5% blending would create large new hydrogen demand; 100% hydrogen enables deep emissions reduction for the long term.

- **Give focused support to those transport options where hydrogen has most to offer.** This could make fuel cell vehicles more competitive and promote the development of core infrastructure. Existing 2030 government targets require 2.5 million fuel cell vehicles on the road and 4 000 refuelling stations. Such a scale-up could reduce fuel cell costs by 75%.

- **Kick-start the first international shipping routes for hydrogen trade.** Lessons from the successful growth of the global LNG market can be leveraged. International hydrogen trade needs to start soon if it is to make an impact on the global energy system.

The chapters in this report highlight a wide range of ways in which hydrogen can be produced, distributed and used as part of a changing energy system. Each application of hydrogen could play an important role in supporting clean energy transitions, but also faces significant challenges and competition.

This chapter synthesises and summarises the analysis set out in previous chapters. It identifies the next decade as a critical opportunity for scaling up hydrogen technologies and supply chains so that they can fulfil their potential. It then charts the steps that governments, companies and others can take in the near term and in different policy contexts around the world. It identifies particular near-term opportunities for deployment in four complementary value chains, and reviews what policymakers need to do to support them. Governments have a central role to play in setting the overarching long-term policy framework for investment, establishing consensus around national opportunities for hydrogen, and also creating market demand, removing regulatory barriers, directing research and engaging internationally. The chapter concludes with a list of priority next steps.

Key findings from IEA analysis

Hydrogen is already in use in a number of important sectors. Demand for hydrogen in its pure form is estimated to stand at around 74 MtH_2/yr, and industry has already demonstrated that it can be produced, stored and distributed on a large scale. Indeed, as much as 6% of natural gas demand is directed to hydrogen production today, mostly for refining and chemicals manufacture.

Almost all hydrogen for industrial use is currently produced using unabated fossil fuels, and demand for cleaner hydrogen remains limited despite previous waves of interest in this topic. However, good reasons are emerging to conclude that this is changing. There is now a greater focus on the deep emission reductions that hydrogen can help deliver, a wider recognition that hydrogen can help to achieve a broad range of policy objectives, a growing awareness that hydrogen can complement expected high levels of renewables in various important ways, and a growing body of experience with low-carbon technologies across the board on which governments and investors alike can draw.

Overall, hydrogen's potential is split between:

- Existing applications of hydrogen, where opportunities are available to use hydrogen produced using cleaner production methods and to make use of a more diverse set of energy sources.
- A wide range of potential new applications for hydrogen, as an alternative to current fuels and inputs, or as a complement to the greater use of electricity in these applications. In these cases – for example in transport, heat, iron and steel and electricity – hydrogen can be used in its pure form, or converted to hydrogen-based fuels.

The number of countries with polices that directly support investment in hydrogen technologies is increasing, with a rising focus on the first of these two types of contribution, but with support for new applications such as road transport as well. Governments have a critical role to play and are working with an increasingly strong and diverse stakeholder community to address key challenges, including: high costs; policy and technology uncertainty; value chain complexity and infrastructure requirements; regulations and standards; and public acceptance. Tackling these challenges is not optional if hydrogen is to get more than a toehold in the broader energy system.

The wide range of applications for hydrogen varies in long-term potential and near-term opportunity

The potential applications for hydrogen reviewed in this report cover almost all facets of energy demand in the modern economy. They are not all equal in their scale, maturity or potential contribution to deep emission reductions in their sectors. Targets and existing and planned projects around the world show that the speed of deployment in coming years is expected to vary widely between sectors. Some, such as aviation, shipping, iron and steel and chemicals, have very high levels of potential future demand for hydrogen and hydrogen-based fuels and face few competitors from other low-carbon technologies. The likely lead times mean that there is a critical need to accelerate development in the near term in order to meet long-term climate objectives, but the opportunity for deployment by 2030 is limited (Table 10). Other sectors offer opportunities for more rapid near-term deployment. Realising specific near-term opportunities for hydrogen at scale will help to boost low-carbon technologies generally, for example through the application of CCUS to refinery hydrogen production and the development of business models for the operation of electrolysers and hydrogen storage in ways that benefit the power grid.

Table 10. Applications for low-carbon hydrogen classified by the theoretical size of the 2030 opportunity and the long-term potential

Type of application	Application	Size of the 2030 opportunity (ktH2/yr)	Long-term potential scale
Major hydrogen uses today	Chemicals (ammonia and methanol)	Over 100	High
	Oil refineries and biofuels	Over 100	Medium
	Iron and steel (blending in DRI)	10-100	Low
New hydrogen uses for a clean energy system	Buildings (conversion to 100% hydrogen)	Over 100	High
	Road freight	Over 100	High
	Passenger vehicles	Over 100	Medium
	Buildings (blending in the gas grid)	Over 100	Low
	Iron and steel (conversion to 100% hydrogen)	10-100	High
	Aviation and maritime transport	Under 10	High
	Electricity storage	Under 10	High
	Flexible and back-up power generation	Under 10	Medium
	Industrial high-temperature heat	Under 10	Low

Notes: Long-term potential scale is a judgement of the technical potential and the extent to which hydrogen faces competition from other low-carbon options in this application. The size of the 2030 opportunity reflects announced plans and targets for scale-up of clean hydrogen in these applications around the world.

Source: IEA 2019, all rights reserved.

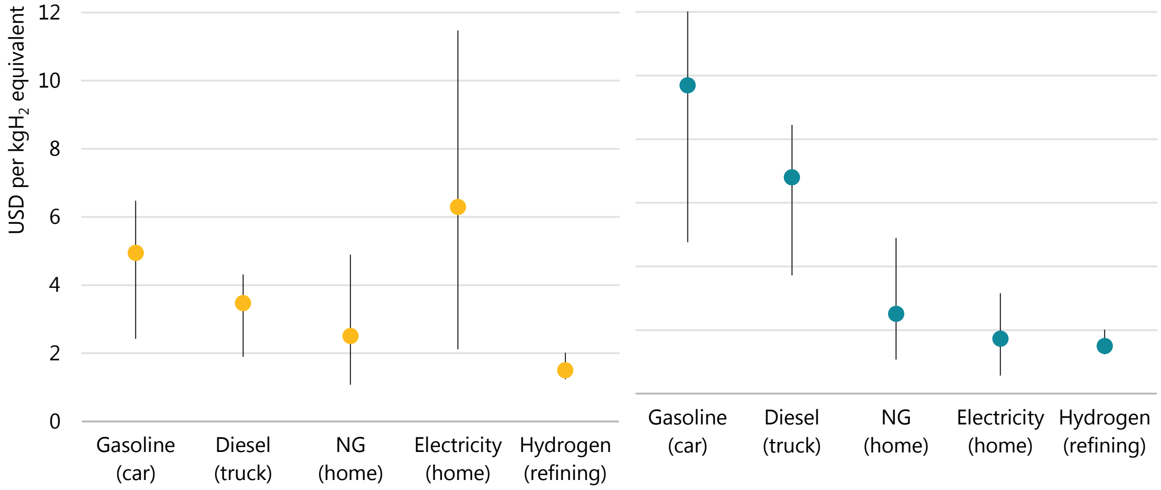
Based on current plans, low-carbon hydrogen demand could pass 100 ktH$_2$/yr in existing industrial applications and gas grids by 2030; iron and steel, aviation and shipping have longer-term potential.

These differences between the applications can be used strategically to support a carefully thought through step-by-step approach to building hydrogen supply chains, experience and infrastructure. Near-term investments in one sector or application can benefit and trigger long-term deployment in other related sectors.

Hydrogen is a relatively expensive fuel and a feedstock that can be used for climate change mitigation in most, but not all, energy applications today. Low-carbon hydrogen production costs are generally lowest from natural gas combined with CCUS: they are as low as USD 1.5/kgH_2 today in the Middle East and North America, and this method of production looks set to remain a low-cost hydrogen production pathway through to 2030. Where CCUS is not a preferred or feasible option, electrolytic hydrogen is not much more expensive in some cases, but is cheapest when produced at high full load hours and not in response to relatively infrequent low prices for renewable power. In the People's Republic of China ("China") and some other countries electrolytic hydrogen can be produced for USD 3–6/kgH_2 in most locations – and this cost could potentially fall to USD 2–5/kgH_2 by 2030. Due to significant differences in low-carbon electricity costs and the attractiveness of CCUS between regions, opportunities exist for international hydrogen trade, which would add around USD 1.5–2.5/kgH_2 to delivered hydrogen costs, depending on the end use. This is equivalent to an electricity price differential of USD 31–52/MWh in the case of electrolytic hydrogen.

In the transport sector today consumers already pay prices for energy (including taxes) that are comparable to low-carbon hydrogen supply costs (Figure 65). For early deployment, this indicates that the cost gap may not be large and could be bridged in part by governments, for example with time-limited tax exemptions for first movers. In other sectors, such as refining and industry, there is potential to bridge part of the cost gap by marketing a version of existing industrial products with a lower CO_2 intensity. A market for lower-carbon industrial products could be created by consumer demand or policy intervention, and would help reduce the direct costs to taxpayers of low-carbon hydrogen projects in these sectors.

Figure 65. Today's fuel prices in hydrogen-equivalent terms on an energy basis (left) and accounting for the relative efficiencies to provide the same service (right)



Notes: Average prices paid in IEA countries plus China. Prices include taxes and tariffs. Fuel cell and motor drivetrain assumed to be 96% more efficient than an internal combustion engine. Heat pump assumed to be 3.6 times more efficient than heating with hydrogen. NG = natural gas.

Source: IEA (2018a), *World Energy Prices 2018*.

After accounting for the efficiency of converting hydrogen to motive power, the price paid by car drivers for gasoline is equivalent to nearly USD 10/kgH_2, which is achievable for delivered hydrogen costs in many regions by 2030.

The next ten years will be critical to keeping hydrogen in the energy policy toolbox

The main driver of wide deployment of low-carbon hydrogen is its potential to help reduce carbon emissions while contributing to energy security and resilience. Governments around the world have committed to ambitious goals for emission reductions, and are wrestling with the challenge of how best to achieve those goals without taking any risks with energy security and resilience. The rapid pace of change and the scale of the challenge means that the next ten years are absolutely critical.

Precisely how hydrogen will ultimately fare against other low-carbon options cannot be known, but there is a clear long-term rationale for ensuring that the fullest possible range of options is available to help tackle multiple energy system challenges – including energy security, affordability, access and sustainability – for a growing global population and economy. Put another way, it seems foolhardy not to keep the option of large-scale, clean, flexible hydrogen on the table.

"Ambitious pragmatism" will be essential to build momentum, to support the development of low-cost and low-carbon hydrogen on a large scale, and to help position hydrogen to be ready to compete and seize longer-term opportunities. Much progress has been made with hydrogen over the last ten years, but it takes time for new energy technologies to penetrate existing markets. A decade is not long to further expand supply and demand to a point of shared confidence between governments, investors, equipment suppliers and others in the sustainability of hydrogen markets. It took almost 25 years from the introduction of the first market-creating feed-in-tariff for renewable electricity to the point where solar PV made up 1% of global electricity output.

Building an effective springboard would involve scaling up low-carbon hydrogen supply in a way that encourages innovation, efficiencies and cost reduction. Mass manufacturing of electrolysers, fuel cells and components of refuelling stations will spur cost reductions, especially if international standards are agreed. Scale will also reduce the costs risks associated with major investment in technologies for making hydrogen-based fuels and feedstocks, and in common infrastructure, including pipeline conversions, new pipelines, CCUS infrastructure and shipping terminals.

Near-term opportunities

Smart policy is needed to put the world on a pathway that enables these long-term goals to be met. Hydrogen value chains are complex and the risks faced by investors are significant. Co-ordination problems between different parts of value chains persist, costs are changing quickly and technologies (including competitors to hydrogen in some applications) are developing rapidly. Regulations and standards vary between regions and are expected to undergo revision, creating uncertainty for companies and investors. Against this background, the case is strong for focusing near-term action on applications where the barriers to deployment can be most easily overcome. Four value chains present a particular opportunity over the next decade to make a step-change in the pace of hydrogen deployment.

Four key value chains

These four value chains together represent a major opportunity to build a 2030 springboard for hydrogen to fulfil its longer-term potential (Table 11). They are combinations of hydrogen supply and demand that emerge from the analysis in Chapters 2 to 5, focusing on lower-cost and nearer-term opportunities that build on existing policies, infrastructure, skills, geographical advantage and demand for hydrogen. This approach minimises risk for governments and the private sector, while still achieving significant scale.

Table 11. Four value chains representing opportunities for scaling up hydrogen in the near term

	Value chain name	Contribution to 2030 goals	Focus regions
1	Coastal industrial clusters	To open gateways to lower-cost and lower-carbon hydrogen hubs	Europe, China, Japan, Latin America, United States
2	Existing gas infrastructure	To scale up low-carbon hydrogen supply by tapping into dependable demand	North America, Europe
3	Fleets, freight and corridors	To reach appropriate scale for competitive fuel cell vehicles and refuelling	China, Japan, Korea, Europe, South Africa, United States
4	The first shipping routes	To kick-start international hydrogen trade for ultimate global low-carbon market	Asia Pacific, Middle East, North Africa, Europe

Each of these value chains is described in more detail in this chapter, and their policy requirements identified. The four value chains are not independent, as developments in one will benefit the others in realising cost reductions and innovation. Furthermore, within the same region there could be opportunities to exploit synergies between them, for example for truck fleets operating between industrial clusters and along transport corridors. Reaping the cost benefits of economies of scale in hydrogen supply and distribution is likely to require the cumulative demand of several sectors in a region, not one application alone. For example, a growing hydrogen network for vehicle refuelling could help launch flexible low-carbon power generation. Success in each of the value chains will help provide the conditions for success in others.

Five types of policy need to work together

Regardless of which value chains individual governments wish to explore and develop, policy efforts will be needed with the aim of:

1. Establishing targets and/or long-term policy signals.
2. Supporting demand creation.
3. Mitigating investment risks.
4. Promoting R&D, strategic demonstration projects and knowledge sharing.
5. Harmonising standards, removing barriers.

Targets and/or long-term policy signals are needed to provide stakeholders with certainty that there will be a future marketplace for hydrogen. Climate policies, in particular, will be crucial in this regard. Actions could include the putting in place of high-level instruments such as emissions reduction targets, or commitments to deploy certain energy resources or carbon pricing systems. In the transport sector, 2030 deployment targets for fuel cell vehicles and hydrogen refuelling stations already play this role in several countries.

Targets alone, however, will not be sufficient to develop an effective springboard for the four value chains over the next decade. The following sections examine these near-term value chains in turn, describing specific examples and targeted recommendations for each under the five policy categories set out above. These recommendations are aimed at helping various end-use sectors to embrace a switch to new cleaner fuels and feedstocks. For each value chain, policies that are technology neutral are preferable, but can be complemented by additional measures to support promising hydrogen technologies as they scale up towards cost-competitiveness.

Taken together, the value chains offer a cost-effective, practical path toward ensuring that hydrogen in 2030 will be primed to play a potentially critical role in the longer-term global effort to achieve a clean, secure, resilient and cost-effective global energy system. In addition to the specific measures needed for each value chain, a number of measures are likely to be needed regardless of which hydrogen sources and applications are supported. These are presented in Table 12 and apply to all four value chains.

There is no one-size-fits-all for hydrogen policy

Individual countries will always base their policies and actions on the social and political priorities and constraints facing them, as well as resource availability and existing infrastructure. That is the case for all energy technologies and is certainly the case for hydrogen. Some countries may wish to prepare the ground for larger and cleaner future hydrogen products and markets by exploiting near-term opportunities based on fossil fuels and take a phased approach to shifting to low-carbon hydrogen. This approach might help enable scale-up in the near term. However, the limited environmental benefits of such an approach, or even negative environmental impacts, mean that a strategy to deploy CCUS or low-carbon hydrogen at a later stage is essential. Other countries may choose to build up hydrogen products and markets solely based on a chosen set of low-carbon sources, such as renewable electricity. In both cases, there may be opportunities to draw upon energy resources that are currently underutilised or used in lower-value applications today in ways that help manage near-term cost and risks (in Box 17). If it is possible to use these resources in high-value applications, such as transport or chemicals, it can raise the efficiency of the whole system.

Whatever policy options different governments choose, however, their signals will be much stronger if their levels of ambition and timing are broadly aligned across different levels of government and internationally. Hydrogen producers and supply chains will need to be able to access financing based on an international outlook and the largest possible markets for scale-up.

Box 17. Putting low-cost energy resources to higher-value uses

As a chemical energy carrier, hydrogen can redirect both chemical and electrical energy into applications that are currently configured to use primarily chemical energy, such as transport. Four main sources of undervalued energy resources could be redirected to supply hydrogen refuelling stations, or other sources of demand for hydrogen and hydrogen carriers:

- **Curtailed and under-remunerated renewable electricity**. Although curtailment in China is declining, over 100 TWh of solar, wind and hydro output were curtailed there in 2017 (IEA, 2018c), roughly equivalent to the level of electricity consumption in the Netherlands. In Germany, 5.5 TWh of power were curtailed in 2017 (Bundesnetzagentur, 2018). Redispatching and curtailment costs amounted to USD 1.2 billion in Germany in 2017 and USD 1.1 billion in the United Kingdom in 2018 (Bundesnetzagentur, 2018; National Grid, 2019). There would be obvious benefits from making productive use of curtailed output. In 2018 three German grid operators announced plans for a 100 MW electrolyser in Lower Saxony where there is regularly too much offshore wind energy for the existing grid, with refuelling stations cited as providing potential hydrogen demand (Tennet, 2018). Besides curtailment, some renewable electricity installations receive less revenue when they produce most energy because spot prices fall in response to high output from wind or solar or both. To hedge this risk, project developers – including hydropower operators that sometimes have "spill" water – could contract with off-takers at an agreed price. However, the incentives and power prices would have to be very attractive to offset the reduced number of hours the electrolyser can operate on this power source (Chapter 2) and the costs of buffer hydrogen storage to manage variability.
- **Inflexible power plants**. Some co-generation plants overproduce electricity at times of high heat demand when the local power grid does not have sufficient power demand. This is the case in North East China, for example, where the inflexibility of coal plants caused by heat loads was a factor in the curtailment of 40 TWh of wind power in 2017. Until the heat demand in these regions is met by other sources of energy, production of hydrogen via electrolysis could potentially be used to avoid curtailment of either coal or renewable electricity if sufficient full load hours of the electrolyser are possible at low power prices. In the longer term any use of coal to produce hydrogen would need to be coupled with CCUS in order to deliver emissions reductions.
- **By-product and vented hydrogen**. Some industries produce hydrogen as a by-product that they do not need (for example steam crackers, chlor-alkali electrolysers and propane dehydrogenation). Merchant hydrogen suppliers collect and purify some of this hydrogen for sale to refineries, chemical plants and others. However, up to 0.5 MtH_2 worldwide is currently vented to the air from these processes. Another 22 MtH_2 is used for relatively low-value applications such as heat and power generation without purification. In combination, this theoretically represents enough hydrogen to power 180 million cars.
- **Renewable gas**. Biogas from anaerobic digesters, dairy farms and landfill is often used for relatively low-value local heat applications. By treating the gas, these resources can be injected in the gas grid and, if accounting systems are in place as in California, sold "virtually" to operators of existing hydrogen production plants running on natural gas.

These resources are not available in all places, but where they are available they could reduce emissions and the need for new investment, potentially decreasing co-ordination challenges.

Sources: IEA (2018b), *Market Report Series: Renewables 2018*; Bundesnetzagentur (2018), *Monitoring Report 2018 – Key Findings*; National Grid (2019), *Monthly System Balancing Reports*; Tennet (2018), "Gasunie, TenneT and Thyssengas reveal detailed, green 'sector coupling' plans using power-to-gas technology".

Table 12. Five key policy categories and examples of cross-cutting policy needs for hydrogen scale-up regardless of the value chains pursued

Policy category	Policy needs	Purpose	Cross-cutting examples
1. Targets and/or long-term policy signals	Public and private commitments to a vision for the 2030 and 2050 role for hydrogen, embedded in an overarching energy, environment and industrial policy framework with measures for delivery.	Provide all stakeholders with more confidence that there will be a future marketplace for low-carbon hydrogen and related technologies, supporting investment and co-operation between companies and countries. Includes: national hydrogen roadmaps and targets for hydrogen use; economy-wide emissions targets; national industrial strategies; international agreements and commitments.	Nationally determined contributions under the Paris Agreement; European Commission climate-neutral strategy for 2050; UK Climate Change Act; draft laws for carbon neutrality in 2050 in France and Germany; Japan's Basic Hydrogen Strategy; China's Ecological Civilization commitment; Make in India; The Netherlands Climate Law and Agreement.
2. Demand creation	Policies that put an economic value on hydrogen for use in new applications or from new sources, growing hydrogen demand across different applications in an integrated way International co-operation that helps synchronise scale-up of hydrogen demand, reduce risks relating to competitive pressures for trade-exposed sectors and underpin investment in manufacturing capacity.	Scale up commercial deployment using demand-side policies that "pull" investment throughout the value chain, making projects bankable. In several applications, hydrogen technologies are ready to move beyond demonstration projects and, with policy support to close the price gap, into self-sustaining businesses, understood by financers. Includes: portfolio standards; CO_2 and pollution pricing; mandates and bans; performance standards; public procurement rules; electricity and gas market rules (including markets for auxiliary services and locational, temporal pricing); tax credits; reverse auctions. Highly technology prescriptive policies should be avoided, but all should be open to hydrogen on equal terms, for example in auctions for low-carbon electricity integrated with power storage.	Canadian Clean Fuel Standard; California Low Carbon Fuel Standard (LCFS) and Zero Emissions Vehicle (ZEV) mandate; EU Emissions Trading System, Clean Vehicles Directive and emissions standards for cars and trucks; Dutch public procurement provisions for low-carbon materials; UK Renewable Transport Fuel Obligation (RTFO); US 45Q tax credit for CCUS.

Policy category	**Policy needs**	**Purpose**	**Cross-cutting examples**
3. Investment risk mitigation	Measures that help tip the balance in favour of private investment in discrete facilities in the earlier stages of scale-up when risks are dominated by uncertain demand, unfamiliarity and value chain complexity.	Address the many applications for hydrogen entering the "valley of death" where demand creation policy is insufficient on its own to make projects bankable or overcome co-ordination market failures. Policies to address risks associated with both capital and operational costs are needed. Includes: loans; export credits; risk guarantees; accounting systems that enable trading of "guarantees of origin"; tax breaks; regulated returns; water resource and CCUS planning.	Chinese policy bank loans; Australia's Clean Energy Finance Corporation; EU projects of common European interest; EIB Energy Lending Policy; multilateral bank financing; EU Connecting Europe Facility; Southern California Gas Company renewable natural gas certification.
4. R&D, strategic demonstration projects and knowledge sharing	Governments need to continue playing a central role in setting the research agenda for early-stage high-risk projects, taking early-stage risks and crowding in private investment in projects. For technologies at the point of market scale-up and lower-risk projects, a range of policy tools can incentivise the private sector to take the lead in driving innovation based on market needs and competition.	Meet the need for better-performing and lower-cost technologies that operate in an integrated manner and are more cost-effective to produce and install. Includes: direct project funding and co-funding; tax incentives; concessional loans; complex demonstration co-ordination; equity in start-ups; multilateral collaboration initiatives; targeted communication campaigns; prizes. Cross-cutting, non-sector specific areas of need: • Electrolysers: efficiency; lifetime; manufacturing and installation costs; recyclability; oxygen production. • Fuel cells: precious metals content; efficiency; recyclability; manufacturing costs; storage tank costs. • Safety of hydrogen, ammonia, toluene: understanding of implications of new uses; management techniques. • CCUS and methane pyrolysis: Capture rates > 90%; inte-grated demonstrations of pre-commercial approaches. • Hydrogen-based fuels/feedstocks: flexibility and efficiency of Haber-Bosch, methanation, Fischer-Tropsch. • Storage: solid-state; lightweight tanks; porous media. • DAC: capital costs; efficiency; sorbent costs; integration with exothermal processes (e.g. Fischer-Tropsch). • Biomass: gasification efficiency and costs.	US Department of Energy Hydrogen and Fuel Cells Program and H2@Scale; Japanese NEDO Roadmap for fuel cells and hydrogen; EU Horizon 2020 and the public-private partnership on Fuel Cell and Hydrogen (FCH JU); Germany National Innovation Program for Hydrogen and Fuel Cell Technology; French Hydrogen Plan; Mission Innovation challenge; Clean Energy Ministerial initiatives.

Policy category	Policy needs	Purpose	Cross-cutting examples
5. Harmonising standards, removing barriers	Lower or remove unnecessary regulatory barriers and establish common standards that facilitate trade and ensure safety for all the elements in the value chain. Engage local communities to ensure they can make informed decisions about the risks and impacts of new hydrogen projects.	Assist the market uptake of hydrogen technologies by removing barriers that prevent adoption or increase risks, and address potential public concerns. Cross-cutting issues include safety standards, avoiding double taxation of energy where applicable, and distribution purity and pressure. A key issue is the certification of CO_2 intensity and provenance of hydrogen supplies, as well as benchmarks for the incumbent processes they replace. An international framework is needed that is robust against mislabelling or double-counting of environmental impacts (so-called "guarantees of origin") and covers CO_2 inputs to hydrogen-based fuels and feedstocks.	Hydrogen Technology Collaboration Programme; International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE); International Organization for Standardization (ISO) TC 197; International Electrotechnical Commission TC 105; CEN Sector Forum Energy Management; HySafe; EU CertifHy; CSA Group.

1. Coastal industrial clusters: Gateways to building clean hydrogen hubs

Clusters of industrial activity offer a major opportunity for ramping up the deployment of low-carbon hydrogen. They reduce the need for upfront investment in transmission and distribution infrastructure because demand and supply of hydrogen can be co-located (Figure 66). They reduce the need to develop demand and equipment for hydrogen use in new sectors because many industrial hubs already have large established users of hydrogen for refining and chemicals, including ammonia. And they offer large and rising volumes of hydrogen demand, reflecting the fact that the use of hydrogen for refining, ammonia, methanol and steelmaking is set to grow in all IEA scenarios and in many existing industrial hubs (Chapter 4).

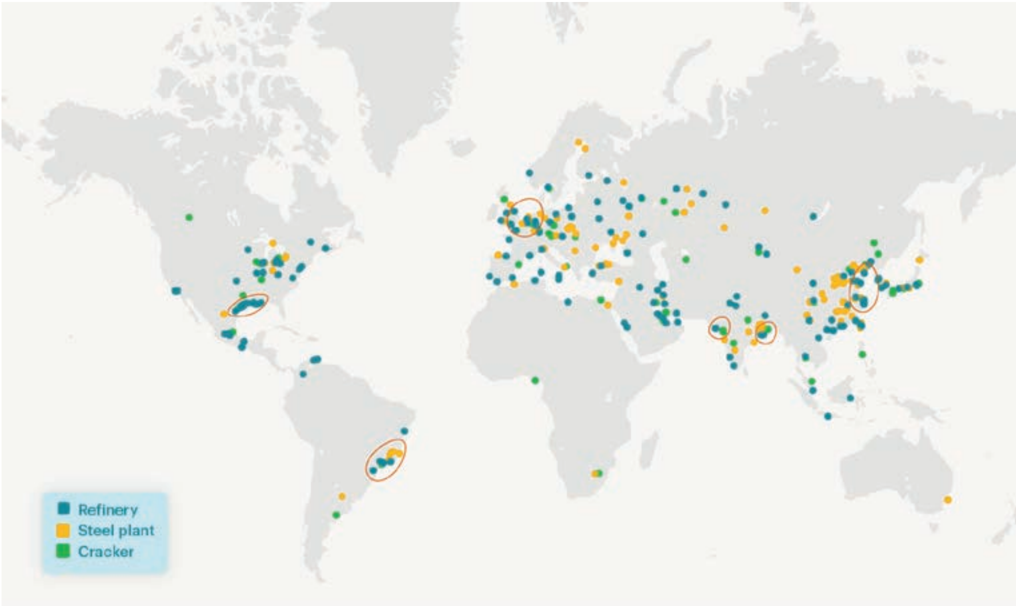
Replacing even a small percentage of current hydrogen use in refining, steel or ammonia production would, however, require a large step-up in supply of low-carbon hydrogen from electrolysis or CCUS. The largest water electrolysers proposed today are around 100 MW, equivalent to around 10% of a single steel plant's hydrogen demand.

The reasons why *coastal* industrial hubs are of particular interest for hydrogen value chains are fourfold:

- Much of the 74 Mt of existing demand for pure hydrogen is already at coastal hubs, as is much of the 45 Mt of demand for hydrogen in mixtures of gases and almost all of the dedicated hydrogen pipeline and storage infrastructure. In several cases – such as the US Gulf Coast and in Belgium, France and the Netherlands – these clusters already have hydrogen pipeline networks that might be built upon for trade in new hydrogen sources. The global distribution of existing refining, steelmaking and chemicals production indicates several such clusters (Figure 66), and these sectors are all growing: annual demand for hydrogen for refining, ammonia and methanol is already set to rise nearly 20% to 96 Mt by 2030.

- There is the potential to integrate industry or transport applications at coastal hubs with nearby sites for offshore wind and solar PV in locations such as the North Sea in Europe, Southeast China, Western Australia and Northwest India.
- Coastal industrial hubs are often located near oil and gas operations and potential CO_2 storage sites (including enhanced oil recovery operations) in locations such as the Gulf of Mexico, the Persian Gulf, Australia's Victorian and Pilbara coasts and the North Sea.
- There is future potential to use port facilities to support both international hydrogen trade by ship and the use of hydrogen and hydrogen-based fuels for trucks and fleet vehicles and as maritime and inland shipping fuel.

Figure 66. Global distribution of existing refining, steelmaking and chemical cracking plants



Notes: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area. Sites shown are those with capacities of over 0.2 mb/d for refineries, over 2 Mt/yr for steel plants and over 0.3 Mt/yr for steam crackers.

Sources: IEA analysis based on Oil & Gas Journal (2018), *Worldwide Refinery Survey – 2018*; Platts (2018), *Olefins Database*; Steel Institute VDEh (2018), *Plantfacts Database*.

The distribution of industrial hydrogen demand today is concentrated in key coastal clusters.

Several of today's major industrial clusters have already independently recognised this potential, and public and private initiatives for hydrogen have been put in place, sometimes by national governments and sometimes by regional communities. These include H2V Industry in France, HyNet North West in the United Kingdom, the Northern Netherlands Innovation Board, and Taranaki in New Zealand.

In the long term, industrial hubs are particularly promising locations for expanding hydrogen use into other sectors. For example, supplying hydrogen to residential heating, hydrogen refuelling stations or dispatchable power generation could build on the production facilities and infrastructure built for industrial applications. These potential sources of hydrogen demand often exist close to industrial hubs and offer many potential synergies. A single 500 MW power plant would, for example, create hydrogen demand equivalent to 650 000 FCEVs or the heat demand of 2 million homes (Chapter 5). Hydrogen use could spread gradually from coastal hubs further inland by truck, barge or pipeline (since industrial clusters are often well-integrated with existing natural gas pipelines).

There are already examples of plans that show the potential for costal hubs as hydrogen users. At the ports of Los Angeles and Long Beach, for example, the Zero and Near Zero Emissions Freight Facilities project is planning two heavy-duty hydrogen refuelling stations and ten hydrogen-fuelled trucks to distribute goods around the ports with the aim of improving air quality as well as addressing climate concerns.

Potential exists for a variety of coastal industrial clusters to support the commercial-scale demand and supply of hydrogen, including by retrofitting CCUS to existing hydrogen plants. The North Sea is one candidate, but others include South East China, the US Gulf Coast, Australia and the Persian Gulf, where Saudi Arabia plans to explore hydrogen production for shipment to Japan. Some inland industrial clusters could also support hydrogen developments where this makes sense, for example for fertiliser production in inland China (Chapter 2) or for steel production in Austria. The production of hundreds of thousands of tonnes of hydrogen for industrial applications is a major opportunity for expanding electrolyser production and capacity, as well as for CCUS projects.

Box 18. Focus on the North Sea region

The North Sea region exhibits many of the features that can make coastal industrial hubs an attractive starting point for scaling-up (and cleaning up) hydrogen supply and demand:

- strong industrial base with nine key industrial hubs
- strong driver for low-carbon investment in the shape of ambitious climate policies
- hydrogen pipelines
- proximity to CO_2 storage potential
- high potential for offshore wind power
- political interest in hydrogen as fuel and feedstock in the context of maintaining a strong industrial base in the region.

The nine industrial hubs around the North Sea currently consume a total of 1.7 MtH_2 annually, nearly half of which is for ammonia (0.8 Mt), and most of the rest for refining (0.6 Mt) and chemicals (0.2 Mt). Production of this hydrogen is currently responsible for the emission of 15 $MtCO_2$, equivalent to one-third of Germany's CO_2 emissions from the manufacturing and industrial sectors.

The North Sea has some of the best-developed CO_2 storage resources in the European Union. Since 1996 CO_2 has been injected into the Norwegian continental shelf at a rate of 1 $MtCO_2$/yr, more than twice the amount needed to abate emissions from a large-scale hydrogen production plant. While progress since then has been slow, North Sea projects to capture and store CO_2 from natural gas-based hydrogen production are now among the leading candidates for CCUS in Europe. While no final investment decisions have yet been taken, projects at the feasibility study stage with ambitions to be operational by 2030 include: the H21 project in the North and North East of England, which would involve nine hydrogen production units of 0.2 MtH_2/yr capacity each (H21, 2018); the Magnum Project in the Netherlands, which could create demand for 0.2 MtH_2/yr for each of the three gas power plant units converted to hydrogen (NIB, 2018); the H-Vision project, which aims to retrofit CO_2

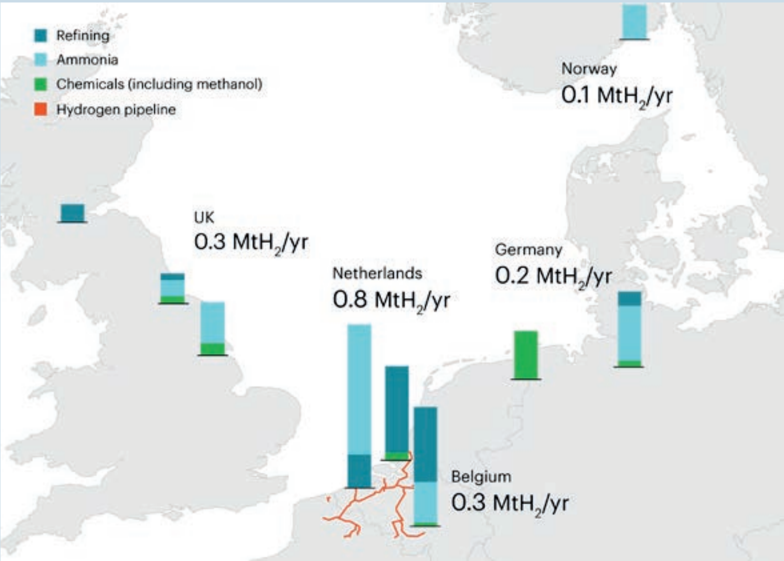
capture to up to 0.6 MtH_2/yr for industrial use in Rotterdam, the Netherlands (PoR, 2018); and the HyNet project in North West England, which proposes 0.2 MtH_2/yr capacity for industrial use and injection into the gas grid (Cadent, 2018).

Several of these projects plan to use domestic natural gas resources and store the CO_2 under territorial waters, but in some cases the project proponents intend to import natural gas for local hydrogen production and re-export the CO_2 for storage, for example in the Norwegian continental shelf. Another alternative is to import the hydrogen from hydrogen production close to the overseas CO_2 storage site. Policies and public funding conditions can be instrumental in determining which approach is followed, for example by supporting only local hydrogen supplies.

The North Sea already hosts 13 GW of offshore wind, and national targets for 2030 could take this above 50 GW. By creating new demand for electricity on the coast, electrolysers can prevent the power generated by offshore wind going to waste where electricity grid connections are not sufficient to transmit all of the output to demand centres at windy times. If 5% – the level of wind electricity subject to curtailment in Germany today – of the targeted North Sea offshore wind output in 2030 were used to produce hydrogen, around 0.2 MtH_2/yr of low-carbon hydrogen could be supplied. This could satisfy more than 10% of the today's industrial hydrogen demand around the North Sea. Several proposals have already been made to link offshore wind output to industrial clusters and, as part of this, to make use of large-scale hydrogen storage, including in North East England (H21, 2018), Northern Netherlands (EnergyStock, 2019; ReNews, 2019) and facilities on an artificial island (NSWPH, 2019). In the longer term, pairing renewable electricity capacity with hydrogen production for transport and industry could be attractive for matching electricity demand with supply.

Sources: H21 (2018), *H21 North of England*; NIB (2018), "The green hydrogen economy"; PoR (2018), "H-Vision: Blue hydrogen for a green future"; Cadent (2018), *HyNet North West: From Vision to Reality*; EnergyStock (2019), "The hydrogen project HyStock"; ReNews (2019), ; NSWPH (2019), "Planning the future today".

North Sea hydrogen demand capacity by sector and pipeline infrastructure, 2018



Notes: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area. Tjeldbergodden in Norway, which consumes 0.1 MtH2/yr for methanol, not shown on map.

Sources: Air Liquide (2019), "Supply modes"; CF Industries (2017), More Ways to Win: 2017 Annual Report; Integraal waterstofplan Noord-Nederland (2019), Investeringsagenda Waterstof Noord-Nederland; Roads2Hy.com (2007), "European hydrogen infrastructure atlas" and "Industrial surplus hydrogen and markets and production"; Yara (2018),"Annual production capacity"; data provided directly to IEA by Port of Rotterdam.

There is already substantial demand for hydrogen in North Sea industrial clusters.

Near-term policy priorities

Targets and/or long-term policy signals. Governments at all levels should look seriously at industrial clusters as opportunities to scale up hydrogen in the 2030 timeframe. Developing cross-sectoral roadmaps and committing to deployment targets can be instrumental to bringing all stakeholders on board and to ensuring that visions for different industries are aligned in scale and timing.

Demand creation. Technology-neutral instruments like CO_2 pricing would provide an overarching incentive for low-carbon hydrogen use, with a price of USD 50 tCO_2 potentially enabling investment in CCUS retrofit at refineries or ammonia plants where CO_2 storage is accessible. Other measures could also help, including legal or voluntary commitments to meet CO_2 intensity goals at a sectoral level (similar to low-carbon fuel standards) or to provide a given share of output from low-carbon inputs (as with renewable transport fuel obligations), public procurement rules or auctions, tax credits, and schemes that allow consumers to differentiate between products so that they can buy low-carbon products if they wish to.

Investment risk mitigation. Supply chain risks and market uncertainty will persist for hydrogen use in most industrial applications over the next decade, especially where final product margins are tight. Specific risks also include cross-border variations in environmental regulations, and the risk of creating monopoly hydrogen suppliers of low-carbon hydrogen at high prices. To help manage these risks, governments might participate in project financing across borders, as in the EU Important Projects of Common European Interest (IPCEI), or organise competitive bidding for hydrogen supply contracts. In individual industrial clusters, or across a broader region, there may be an opportunity to spread risk for potential hydrogen buyers by establishing intermediaries that can sign multi-year contracts for future hydrogen supply, thus pooling their risk according to the scale and timing of their anticipated demand and providing more certainty for investors. Development of CCUS as a service business and special development zones could also help manage risks and therefore minimise costs

R&D, strategic demonstration projects and knowledge sharing. Hydrogen is already extensively used in industry today, so much of the research and cost reduction can be undertaken by the private sector as commercial competition increases, especially on the demand side. On the supply side, public support for the first major applications of CCUS technologies in a given region and large-scale integrated electrolyser demonstrations can help ensure that some of the resulting knowledge is widely shared to accelerate subsequent adoption. However, for novel applications (especially those at low technology readiness levels) and complex demonstrations, there might still be a case for public R&D support. Demonstration projects must be linked to overall energy policies and strategies, to avoid one-off projects that do not contribute to sustainable scale-up. In the steel sector, 100% hydrogen DRI needs further refinement and demonstration, and the emergent option of ammonia in DRI can be investigated. To facilitate large-scale demand for hydrogen and hydrogen-based products, proving and improving the (co-)firing of hydrogen in turbines and (co-)firing of ammonia in boilers/turbines/fuel cells are needed for de-risking. Improvements to the storage of hydrogen, including as liquid hydrogen, would also be valuable.

Harmonising standards, removing barriers. Areas that would benefit from international harmonisation and common standards include hydrogen purity and pipeline specifications for industry, comparable to ISO standards in the transport sector, safety protocols for the use of hydrogen and hydrogen-based fuels and feedstocks, and "guarantees of origin" (Table 12).

2. Existing gas infrastructure: Tapping into dependable demand

Some 3 million km of natural gas transmission pipeline are in operation around the world today, and even greater lengths of distribution pipeline. These pipelines have near-term strategic value for hydrogen scale-up (Chapter 3). With only modest additional investment in infrastructure or end-use equipment, they would be able to transport the output of new hydrogen production facilities at low marginal costs, reducing the cost of supplying low-carbon hydrogen.

Before 2030 governments will need to take important strategic decisions about the long-term future of natural gas and gas pipelines in order to ensure a smooth transition towards full conversion or, potentially, away from gas grid utilisation altogether. These decisions will confront all gas networks at some point if they are to reduce emissions significantly (including fugitive emissions) because there is no attractive low-carbon alternative. They will have knock-on implications for the investment needs of the electricity grid. Above a blended share of hydrogen of about 20%, the costs of modifying end-user equipment and the grid itself are only likely to be justified by a wholesale switch to 100% hydrogen. The two main ways to use hydrogen in the gas grid – blending hydrogen with natural gas, and converting the grid to 100% hydrogen – are distinct and treated independently in the following discussion.

Blending hydrogen

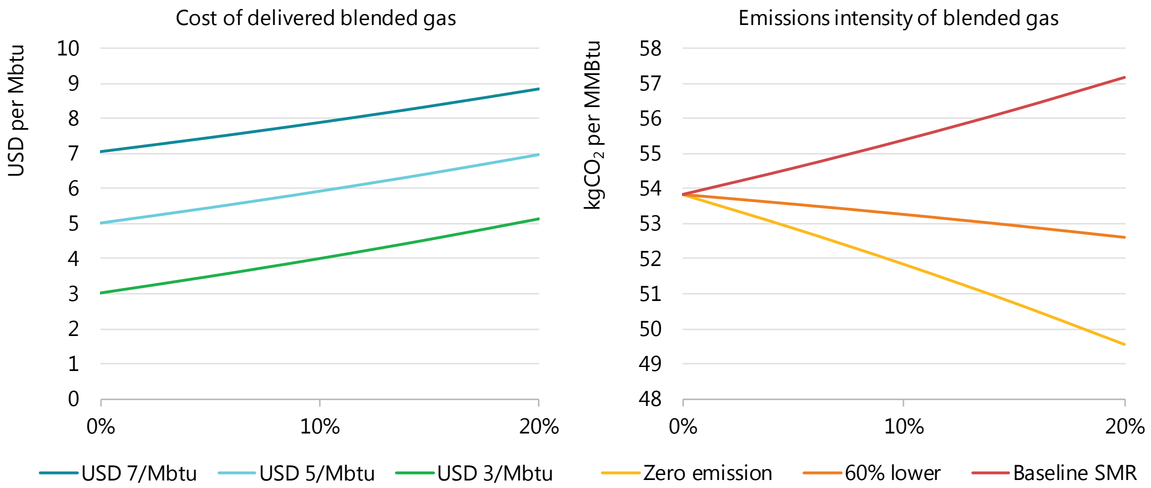
It is possible to blend small shares of hydrogen in existing natural gas systems with only minor changes to infrastructure, equipment and most end-user appliances, if changes are needed at all. Some new investment in hydrogen injection facilities would be needed, but in general blending at a safe level offers a relatively quick and easy way to transmit hydrogen supplies to end users, as long as hydrogen production is well-located near the gas transmission or distribution network.

As described in Chapter 5, several projects around the world are already demonstrating hydrogen blending in the gas grid for use in buildings, and more are planned on a larger scale. Among the larger proposed projects for coming years are electrolysers of 100 MW to 250 MW in Europe and North America that would run on wind or hydro power and inject tens of thousands of tonnes of hydrogen per year into the gas network. There are also proposed projects for blending hydrogen from natural gas with CCUS in Europe, including plans in North West England to inject around 0.6 MtH_2/yr into the gas grid and to supply hydrogen to chemical plants by 2030, thus linking the gas grid and an industrial cluster. If these projects, and the H21 North of England project, go ahead, a sizeable and dependable hydrogen demand of over 2 MtH_2/yr to could be created by 2030.

If hydrogen were blended into all natural gas use in the European Union at just 5% by volume, this would boost low-carbon hydrogen demand by 2.5 MtH_2/yr. If this were supplied by electrolysers then it would require almost 25 GW of water electrolysis capacity. With cumulative installed capacity since 2000 standing at under 1 GW, this would amount to a significant scale-up, promoting efficiency improvements and capital cost reductions of up to one third. The capital investment for 25 GW of electrolyser capacity could be around USD 20 billion, plus an additional investment of over USD 3 billion for injection facilities (FCH JU, 2017). If the hydrogen were sourced from CCUS-equipped facilities instead, costs would likewise be expected to decline (not least because of the benefits that economies of scale bring to CO_2 transport and storage), but less steeply.

The costs and avoided emissions of blending depend on hydrogen costs, natural gas costs and the CO_2 intensity of hydrogen production (Figure 67). At prevailing natural gas costs of USD 5/MBtu, a 5% blend (by volume) of hydrogen costing USD 4/kg would increase delivered gas costs by around 8%,[55] but the impact in terms of larger-scale production and efficiencies should reduce the costs of hydrogen in the future. If the hydrogen and natural gas have no associated upstream greenhouse gas emissions, such a 5% volume blend would reduce the CO_2 intensity of delivered gas by 2%.

Figure 67. Cost and emissions intensity of blending hydrogen into the gas network at different blend shares



Notes: Cost of delivered blended gas with assumed USD 4/kgH_2, emissions intensity of "baseline SMR" = 91.0 kgCO_2/GJ H_2, "60% lower" = 36.4 kgCO_2/GJ H_2 and "zero emission" = 0 kgCO_2/GJ H_2. Blend shares on a volumetric basis.

Source: IEA 2018. all rights reserved.

The cost and emissions reduction from hydrogen blending depend on the source of hydrogen and gas price. A 5% blend of low-carbon hydrogen could reduce CO_2 emissions by 2%.

Conversion to 100% hydrogen

The conversion of existing gas grids to supply 100% hydrogen would lower distribution costs for hydrogen by facilitating much larger-scale supply; it would also enable sources of pure hydrogen demand (for example transport and industrial users) to connect to a common network.

The existing grid is not the only possible way to develop a future hydrogen transmission and distribution infrastructure, but it is likely to be the most cost-effective, especially at the distribution level.[56] Some investment might be needed in key components of the grid, especially on the distribution network, but this should be technically and economically feasible

[55] Cost increases for end users could be lower, depending on tax treatment, pricing models and taxpayer support.

[56] Costs of repurposing plastic distribution pipelines to carry 100% hydrogen are uncertain, but estimated at USD 14 000/km (H21, 2018), whereas new hydrogen distribution pipelines costs range from USD 130 000/km to USD 2 700 000/km, depending on aspects such as labour costs and population density (SGI, 2017). The needs to oversize pipelines in anticipation of future demand growth would add to upfront costs.

(NN, 2018; Dodds and Demoullin, 2013).[57] Where distribution pipelines have been installed or upgraded recently they are likely to use polyethylene or nylon pipes that could carry 100% hydrogen. Existing pipelines do not require new permits, which can take years to acquire, further raising costs and risks and slowing the pace of change. There are also non-economic advantages to making use of existing infrastructure, including continuity of institutional arrangements and the avoidance of construction works, which could arouse opposition from local populations and owners of existing assets.

Converting to 100% hydrogen is a bigger change than blending. Conversion requires an overnight switch to 100% hydrogen supply for each part of the affected network, which means that new compressors and, in some cases, storage facilities, need to be available in advance.[58] It also requires replacement of meters, compressors and monitoring equipment, thorough inspection of older parts of the pipeline, and replacement of current gas appliances. Furthermore, citizens' reactions to such a programme are as yet untested. In the 2030 timeframe, full conversion is expected to be realised in fewer places than blending and only in limited parts of national grids, such as town distribution networks or specific underused transmission pipelines. The H21 project, currently at feasibility study level, proposes a conversion of the UK city of Leeds to 100% hydrogen from the late 2020s, with over 1 MtH_2/yr from natural gas with CCUS from a North Sea industrial cluster (H21, 2018).

Near-term policy priorities

Targets and/or long-term policy signals. The timely development of clear roadmaps would decrease obstacles to grid conversion and help potential hydrogen suppliers estimate future market size. The timeframes for grid upgrade and conversion programmes are long, as are the timeframes for turnover of consumer appliances for gas use. Strategic decisions about future gas infrastructure and heating sources are particularly important in colder climates where heating accounts for a significant share of energy use and CO_2 emissions. Timelines for the first large-scale projects might act as critical milestones in long-term plans.

Demand creation. At current cost levels, even low levels of hydrogen blending require policy support to stimulate demand from gas suppliers and to encourage hydrogen equipment production and infrastructure use. Few such policies are in place today (Dolci et al., 2019). To become a dependable source of low-carbon hydrogen demand, blending could be fostered by setting quotas, emission targets or blend levels for low-carbon gases, analogous to mechanisms for renewable electricity. Strategic consideration would need to be given to the sharing of additional costs if the effect on consumer prices could be counterproductive.

Investment risk mitigation. Governments could reduce the risks associated with investment in new hydrogen supplies for blending into the gas grid by clarifying market and technical conditions (Mulder, Perey and Moraga, 2019). The issues that need clarifying include conditions relating to third-party access, regulated returns for system operators, and consumer protection. Governments and system operators could further help investors to manage risks by taking steps to ensure that existing and future equipment on the grid is able to operate with blended hydrogen, including gas storage, compressors, turbines and home appliances.

[57] The existing low-calorific gas transmission network in the Netherlands, which is becoming underutilised, has steel pipeline grades that are suitable for hydrogen transport (DNV-GL, 2017). By 2030, demand for this gas is expected to have fallen sufficiently to potentially give rise to a unique opportunity to convert a transmission pipeline to 100% hydrogen.

[58] Where transmission pipeline corridors are made up of several pipelines in parallel, these could be converted one-by-one, and local distribution grids also exist that can be isolated from the wider distribution grid and connected to a dedicated hydrogen source.

R&D, strategic demonstration projects and knowledge sharing. There is a rationale for public-sector involvement in improving technologies associated with hydrogen production – electrolysers and CCUS – as well as in helping provide the safety case for hydrogen blending and conversion throughout the supply chain. Public co-funding could also accelerate the development of appliances that use 100% hydrogen, especially if the future size of their markets is uncertain. R&D for underground storage of hydrogen in depleted oil and gas fields and aquifers is likely to be necessary to prove their suitability for use with hydrogen. Higher-risk demonstration projects for localised grid conversions are also likely to need public support. Knowledge sharing could be facilitated by international forums, such as IEA Technology Collaboration Programmes, the Clean Energy Ministerial Hydrogen Initiative and IPHE.

Harmonising standards, removing barriers. As hydrogen in the gas grid, whether blended or 100% hydrogen, will be used in people's homes, ensuring safety is of paramount importance. Public safety concerns or adverse events could seriously impair the speed of deployment or prevent it altogether. Standards will also be important for new appliances and equipment. A key barrier to be addressed is the current low level of blending permitted in many jurisdictions, including where cross-border pipelines exist. Standards, such as those for the tolerance of appliances and equipment to different blending levels, clearly have a role to play here too (Chapter 3). Some energy tax regimes were designed without consideration of an energy product (e.g. electricity) being purchased for conversion to another retail energy product (e.g. gas), potentially leading to "double" consumer taxation; governments should ensure that tax regimes remain appropriate.

3. Fleets, freight and corridors: Make fuel cell vehicles more competitive

The transport sector is overwhelmingly dependent on oil today (92% of the sector's energy use). As the world transitions to alternative transport fuels, low-carbon hydrogen has a role to play in contributing to fuel security and diversification while reducing pollution, although the highly dispersed infrastructure and broad range of suppliers, investors and consumers in the transport sector makes it challenging to bring about a rapid shift to low-carbon fuels. Hydrogen can be an effective alternative to BEVs in long-distance, higher-weight applications (Chapter 5).

While there are several impressive commercial enterprises for hydrogen and fuel cell vehicles today, the next stage will be critical to creating a platform for widespread deployment. It will need to include scaling up production of components and vehicles, attracting more market players, bringing down production costs and ensuring refuelling infrastructure is adequate and strategically located. Various national governments have ambitious 2030 targets for vehicles and infrastructure that would put the sector on a firm foundation and reduce vehicle costs (Box 19). These government targets are generally underpinned by air quality and climate change commitments, which also support parallel, higher targets for BEVs.[59]

[59] If some countries import or store low-carbon electricity in the form of hydrogen or hydrogen carriers it will be more efficient in all cases to use this hydrogen directly in vehicles rather than converting it back to electricity for BEVs.

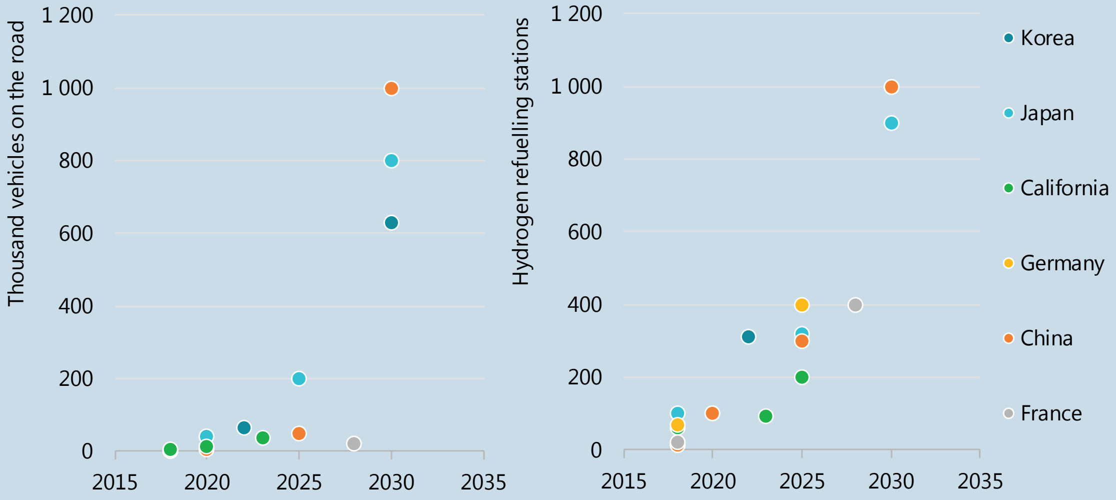
Box 19. Realising existing government targets would drive down costs by 2030

Road transport remains a central feature of most hydrogen projects and policies worldwide., with 40% of the water electrolyser capacity in publicly supported energy projects since 2000 being installed to supply hydrogen for buses, commercial fleet vehicles or passenger cars. Several governments have targets for the deployment of FCEVs and hydrogen refuelling stations which, in combination, would mean putting 2.5 million vehicles on the road by 2030, served by 3 500 hydrogen refuelling stations. This would translate into a hydrogen demand of 0.4 MtH_2/yr, which is almost as much as two large ammonia plants. These numbers would rise after 2030: Korea alone has a target of nearly 3 million FCEVs (cars, buses and trucks) by 2040 to address air pollution and promote industrial growth (MOTIE, 2019).

If these 2030 targets were realised, the impact on cost reductions would be likely to be dramatic. With 2.5 million FCEVs on the road and 3 500 refuelling stations, analysis suggests that fuel cell costs could be reduced by around 75% and refuelling station capital costs could be halved. The IEA estimates that electrolyser costs could also be cut by around one-third if all this hydrogen were to be supplied by electrolysis. These targets would require a very large increase in hydrogen production and in FCEV numbers, although it would only mean achieving a share of FCEVs in the global road vehicle stock that is half of that occupied by all electric vehicles today, or about 0.2%.

Sources: MOTIE (2019), "Government announces roadmap to promote hydrogen economy".

Deployment of FCEVs and refuelling stations and official future targets



Source: AFC TCP (2018), *Survey on the Number of Fuel Cell Electric Vehicles, Hydrogen Refuelling Stations and Targets*; METI (2019), *Strategic Roadmap for Hydrogen and Fuel Cells*.

Opportunities to accelerate deployment

Hydrogen-powered vehicles are not cost-competitive today, but have the potential to become much more competitive as production and use rise in line with the targets set by governments, leading to innovation and reductions in costs (Chapter 5). The road transport sector is also the most active area of hydrogen deployment today, with the highest number of projects and policies (Chapter 1). Meeting these targets, however, requires parallel expansion of infrastructure for hydrogen supply, vehicle refuelling and vehicle manufacturing (including fuel cells). For investors in each component of the value chain, the risks and costs will be multiplied if there are uncertainties about investment in the other components.

The task for policy makers is to identify which types of vehicle to focus on, and how and where to encourage infrastructure development so that the near-term costs to taxpayers are minimised and the strategic long-term value, in terms of decarbonising transport, is maximised. Fleet vehicles, including taxis, light commercial vehicles and buses, with high daily mileage and freight vehicles with fixed corridor routes are promising opportunities, and could help increase the utilisation rate of refuelling stations on the main routes they use – a key determinant of fuel costs. They could also link with industrial cluster value chains to reduce supply chain risks and foster long-term transport hubs, including for shipping.

Trucks are a source of air pollution, and the stringent air quality standards expected in the future would make hydrogen trucks more attractive. As described in Chapter 5, trucks that have a high mileage and large mass are well-suited to hydrogen, but even the whole global truck fleet, at around 56 million heavy- and medium-duty vehicles today, might not be enough units to achieve the needed cost reduction in fuel cells.

Infrastructure deployment strategies will need to be suitable for different fuel cell vehicle types as their markets expand. Once at scale in a given region, hydrogen infrastructure built for the transport sector can be a stepping stone to using hydrogen for flexible power generation, for example. One strategy would be to incentivise the addition of hydrogen refuelling along key transport corridors, given that a relatively small number of the world's busiest highways carry a lot of its commercial traffic: the Beijing-Hong Kong-Macau Expressway, Germany's Autobahn 7 near Hamburg, Highway 401 in Canada and the I-405 in Los Angeles in the United States carry a combined total of around 1 million cars and trucks per day. Another approach would be to start with truck fleets that operate out of coastal industrial hubs, helping to concentrate and scale up initial investment in hydrogen supply.

Because city-level governance will play a critical role in supporting the deployment of both hydrogen vehicles and infrastructure in urban areas, all levels of government need to work closely together so that clusters and inter-city corridors can be selected to intersect with the cities where hydrogen transport is likely to prosper first. California's Zero- and Near Zero-Emission Freight Facilities Project and Germany's H2Mobility initiative show different approaches to this challenge.

Near-term policy priorities

Targets and/or long-term policy signals. Official targets for FCEVs and hydrogen refuelling station deployment exist in at least 18 countries and regions. Others might consider following their example. These targets need to be firmly situated within a robust strategy for transport overall, which should identify the priorities for hydrogen FCEVs alongside BEVs and other transport modes. Long-term transport strategies can encompass aviation, rail and shipping too.

Demand creation. Overarching policy frameworks such as fuel economy standards, renewable fuel obligations and low-carbon fuel standards should include all types of hydrogen supply and value them in accordance with life-cycle emission reductions, alongside other technology options. While non-financial incentives like zero-emission cities and priority lanes, zones and parking spaces can help, significant consumer demand will not materialise without a range of available vehicles at acceptable prices, together with predictable and affordable fuel prices. Initially this is likely to require direct purchase subsidies, tax credits and other measures such as fuel price guarantees from suppliers or governments. Policy makers may choose to offer more attractive levels of support where large equipment orders can be secured for large fleets or networks of refuelling stations, or give incentives to capitalise on the existing refuelling infrastructure along corridors.

Investment risk mitigation. Public policy may need to manage investment risks arising from uncertain supply chains to avoid higher capital costs and hydrogen prices than necessary. For example, a share of electrolyser or refuelling station capacity could receive guaranteed revenue for a limited period, as in California. As has been the case for batteries, clarity over whether electrolysers will be exempt from grid fees, taxes and levies, and under what circumstances, will be important in many markets. Cross-border co-operation to maximise synergies in hydrogen deployment would also help to reduce investment risk.

R&D, strategic demonstration projects and knowledge sharing. Publicly funded research efforts might focus primarily on key cost components, such as fuel cell durability and recycling, on-board storage options and electrolyser efficiency, as well as on earlier-stage technologies likely to be important for shipping and aviation, including use of ammonia in ships, lower-cost means of sourcing "low-carbon" CO_2 and producing synthetic fuels. Demonstration projects involving multiple supply chain partners are likely to be valuable, particularly if focused on the use of intermediate storage to manage variable hydrogen supply streams; the capabilities of hydrogen vehicles such as buses, taxis and delivery vehicles; and safety regulations in jurisdictions where these do not exist for hydrogen value chains.

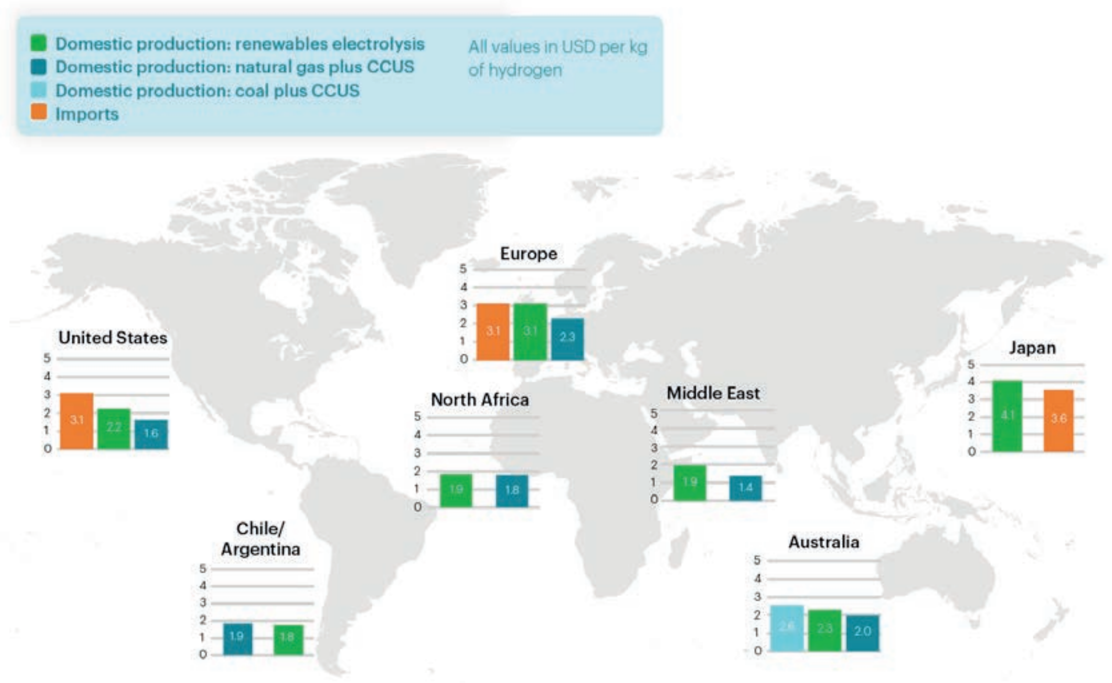
Harmonising standards, removing barriers. The harmonisation of standards across regions and ideally at global level would help to stimulate cost reductions. Among other things, standards are needed for refuelling nozzles for vehicles; hydrogen supply pressures; refuelling station permitting; and safety protocols for high-pressure hydrogen and liquid hydrogen transport by trucks. There is also a case for looking at whether current limitations on the use of hydrogen vehicles on bridges and in tunnels could safely be amended. UNECE Global Technical regulation 13 and various ISO committees are currently exploring several of these issues.

4. The first shipping routes: Kick-start international hydrogen trade

Shipping hydrogen between countries could emerge as a key element of a future secure, resilient, competitive and sustainable energy system. Investment in infrastructure, ships, standards and supply chain companies will have the most impact if located in regions with the greatest potential for hydrogen imports and exports. They are unlikely to happen on a large scale without multilateral co-operation between interested governments.

The cost of hydrogen production varies between regions, with Europe and Japan having relatively high costs and also strong policy support for hydrogen (Figure 68). Hydrogen importers stand to benefit from cheaper low-carbon energy, especially if their domestic renewable energy, nuclear or CCUS resources are challenging or expensive to develop. Hydrogen imports can help maintain energy security in a low-carbon future. Exporters stand to generate new sources of economic value based on clean energy resources. Africa has the potential to produce (for both domestic and export) around 500 MtH_2/yr at less than USD 2/kgH_2, while Chile alone could produce 160 MtH_2/yr at this cost. The Middle East could produce over 200 years of current hydrogen demand at USD 1.3/kgH_2 from known gas reserves that could be combined with CCUS.

Figure 68. Routes for hydrogen trading with long-term costs compared to domestic production.



Notes: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area. Production cost reflects long-term potential (i.e. low CAPEX for wind and solar, see Chapter 2). Electrolysis considers dedicated wind and solar production.
Source: IEA 2019. all rights reserved.

Multiple opportunities exist for international hydrogen trading routes, which could contribute to energy diversification and security, particularly in Europe and Japan.

International trade in energy products takes time to develop. Globally, LNG imports today are around 400 bcm, 10% of global natural gas demand, and Australia and Qatar supply almost 55% of the LNG market. They did not reach these export volumes overnight. Australia's first LNG shipments were 30 years ago in 1989, 10 years after signing the first contract. Qatar's first LNG shipments were in 1997, when globally traded volumes were around one-third of current levels. Overall, it has taken 60 years for global liquefaction capacity to reach the point where 31 liquefaction terminals can now process a total volume of LNG equivalent to Japan's annual primary energy supply, which can be received at 140 receiving terminals around the world. To date there have been no shipments of pure hydrogen, although there is a routine sea trade in ammonia (equivalent to around 3 MtH_2/yr).

Potential hydrogen trade in Asia Pacific in 2030

Japan, Korea and China are world leaders in hydrogen development and all have ambitious targets for 2030 (Table 13 and Box 20). They are also the three largest LNG importers today, together representing 55% of the global market. Each country sees hydrogen as a means of managing environmental concerns without weakening energy security. All three countries are targeting hydrogen use in vehicles; Japan and Korea also have plans for hydrogen use in stationary applications. At 300 MW installed, Korea has one of the largest markets for stationary fuel cell applications, with ambitious plans to expand this to 3.5 GW by 2030. Japan has major plans for imported hydrogen in power generation, reflecting the potential for imported ammonia to be co-fired in existing power plants to reduce CO_2 intensity.

Table 13. Hydrogen demand and supply in Asia Pacific from national and regional roadmaps, 2030

Country	Plans by 2030				Notes
	Hydrogen flow (MtH_2/yr)	Transport (thousand vehicles)	Power generation (GW)	Residential (million homes)	
Australia	0.5				Australia's strategy is likely to be led by exports.
China	0.2	1 000 (cars)			China's strategy focuses on matching domestic supply with domestic demand.
Japan	0.3	800 (cars) 1.2 (buses)	1	5.3	Demand mostly for power generation. Demand from transport is around 0.15 MtH_2/yr and expected to be satisfied domestically.
New Zealand (Taranaki only)	0.7				Taranaki proposes exporting around 0.3 MtH_2 (0.5-1 GW), or 40% of production.
Korea	0.2	630 (cars) 150 (trucks)	3.5		The target for power is for fuel cells, not necessarily hydrogen

Sources: Commonwealth of Australia (2018), *Hydrogen for Australia's Future*; Ministerial Council on Renewable Energy, Hydrogen and Related Issues (2017), *Basic Hydrogen Strategy*; Venture Taranaki (2019), *Hydrogen Taranaki Roadmap*.

While China's focus is currently on the local supply of hydrogen for transport in ten world-scale urban centres for zero-emission vehicles, it could well be a future participant in international hydrogen trade. India has active research projects on hydrogen production, storage and end uses, although it does not yet have any major demonstration projects. Australia is already the largest LNG exporter in the region, with established trade links with other Asian countries. It has large coal and renewable resources that could be converted to low-carbon hydrogen to meet rising demand from Japan and Korea. Australia is still developing its national Hydrogen Strategy, but is likely to prioritise developing an export market over significant domestic use in the near term. One study estimates that hydrogen exports could contribute USD 1.2 billion and provide 2 800 jobs in Australia by 2030 (Commonwealth of Australia, 2018). New Zealand is also looking at possible export markets and has estimated that 0.7 MtH_2/yr could be produced from renewable electricity by 2030, with 0.3 MtH_2/yr available for export (Venture Taranaki, 2018). New Zealand also signed a memorandum of co-operation with Japan in 2018 to develop and expand hydrogen exports, while Singapore is looking into the feasibility of hydrogen imports.

Box 20. Key ongoing hydrogen projects related to hydrogen trade in Asia Pacific

Electrolysis. A 50 MW electrolyser in combination with wind, solar and batteries (150 MW, 150 MW and 400MWh respectively) at Crystal Brook Energy Park, Australia, is expected to move to a final investment decision in 2019 and commissioning in 2021 (Parkinson, 2018). A 30 MW electrolyser project near Port Lincoln, Australia, has AUD 118 million funding for a 2020 start (Government of South Australia, n.d.). This project will produce up to 18 ktH_2/yr.

Fossil fuel-based production. An AUD 500 million project to convert coal with CCUS to 3 tH_2 for liquefaction and shipping to Japan by 2021 has a 50/50 funding split between Australia and Japan for the infrastructure in the two countries by 2021 (DIIS, 2018; HESC, 2019). A USD 100 million pilot project in Brunei to produce 210 tH_2 from natural gas for shipping by liquid organic carrier to Japan for power sector use is under construction for operation in 2020. The Institute of Energy Economics Japan is exploring the feasibility of ammonia imports produced from natural gas with CCUS in Saudi Arabia. This imported ammonia could be used for power generation in Japan. The price of ammonia needs to be USD 350/t to be competitive with power generation from gas and coal in Japan. Kansai Electric Power plans to demonstrate ammonia co-firing with coal by 2020. IHI has been looking into firing ammonia with 20% methane in Yokohama since 2016.

Hybrid. Evaluation of the scope for producing hydrogen from hydropower and natural gas with CCS for shipping to Asia is underway in Norway.

Sources: Parkinson (2018), "Neoen plans world's biggest solar + wind powered hydrogen hub in S.A."; Government of South Australia (n.d.), "Hydrogen and green ammonia production facility"; DIIS (2018), "Local jobs and a new energy industry for the LaTrobe valley"; HESC (2018), "Latrobe Valley".

Hydrogen trade in Europe in the 2030 timeframe

Extensive opportunities are open for hydrogen trade between countries in Europe. The gas grid is the most likely vehicle for such trade, but dedicated cross-border pipelines or internal waterways could also be used. Trade in hydrogen as well as electricity could help smooth low-carbon energy supplies between countries and help match low-cost supplies with demand, and imported hydrogen might be competitive with local production (Chapter 3). This is especially true for electrolysis hydrogen from renewables: production in North Africa from dedicated renewable electricity might have import costs in the near future as low as USD 4.7/kgH_2 for over 500 MtH_2/yr,[60] which compares favourably with USD 4.9/kgH_2 from renewable electricity in much of Europe. Hydrogen from natural gas with CCUS could also be imported from the Middle East at competitive costs as low as USD 2/kgH_2 as ammonia, or USD 2.6/kgH_2 if cracked to pure hydrogen. If CO_2 storage is equally accessible in Europe at similar costs, however, it is likely to be more cost-effective to import the gas and produce hydrogen in Europe. Natural gas can be imported with local conversion to hydrogen with CCUS at a cost of around USD 2.3/kgH_2.

Energy trade with these regions is a pillar of European neighbourhood policy, and is expected to remain so. To support this policy objective the European Union supports energy infrastructure investments in Africa and the Middle East. These regions are included in the scope of the

[60] Water desalination, where required, is estimated to add only 1% to these costs.

European Neighbourhood Instrument, which has a budget of over EUR 15 billion for 2014 to 2020. The Africa–EU Energy Partnership's energy security objectives include doubling electricity interconnections and African gas exports to EU by 2020 compared to 2010. The European Union already imports around 12–14% of its gas demand from North Africa (mainly Algeria), although it is not yet clear whether these pipelines could be repurposed cost-effectively to carry hydrogen at shares above a few per cent.

Near-term policy priorities

Targets and long-term policy signals. Alignment of countries' national hydrogen strategies and roadmaps via bilateral and multilateral partnerships would help the management of risks at both ends of the value chain.

Demand creation. Imported 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. Governments could help make hydrogen cost-effective in target sectors by using portfolio standards, mandates, performance standards, tax exemptions and CO_2 pricing. Exporting countries could stimulate early exports by providing time-limited support to buyers. Infrastructure costs might be minimised by tendering programmes with international support. Reaching sufficient demand to justify investment in import and export terminals, and hydrogen supplies, might similarly be best achieved through international co-operation.

Investment risk mitigation. The first commercial-scale hydrogen export and import infrastructure projects will represent sizeable investments and 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 taking a modular approach and starting with funding smaller projects that reassure financers, 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 from the first projects, insofar as these need not be commercially confidential. It would be very helpful for risk management to have early clarity from governments on the question of tariffs, and to have clear permitting processes in place for hydrogen imports, especially for large, capital-intensive infrastructure projects in first-of-a-kind industries.

R&D, strategic demonstration projects and knowledge sharing. Uncertainty remains about the most effective type of carrier for shipping hydrogen, with much scope for thorough investigation of the options and improvement of efficiency and capital costs. Liquefaction efficiency, boil-off management, scalability and the efficiency of the cooling cycle require improvement. Strategic demonstration projects could target the scale-up of liquefaction and regasification facilities for hydrogen directly or in the form of ammonia.

Harmonising standards, removing barriers. International standardisation will be crucial in this value chain, including for "guarantees of origin",[61] hydrogen purity, the design of liquefaction/conversion and regasification/reconversion facilities, and for equipment specifications. Some IMO regulations may need to be revised and new ones established.

[61] This is described in Table 12. Note: for hydrogen produced with CCUS leading to permanent CO_2 storage or equivalent, a simple approach could be to multiply the hydrogen output by the CO_2 capture rate to calculate a quantity certified "low-carbon" hydrogen. The rest of the hydrogen would be uncertified (i.e. having the CO_2 intensity of unabated fossil hydrogen).

Next steps

What next for analysts?

This report is based on the latest available information and data from publications as well as from government and industry contacts. It builds on the extensive technology and economic modelling expertise of the IEA in each of the sectors that are discussed and contrasted. Yet many gaps in knowledge and analysis remain, including the types of policies that will work best in different sectors. Much could be done to fill these gaps in the next few years by co-ordinated efforts in support of informed decision-making. Much more information will become available in the next five years, not least from the projects and plans highlighted in this report, and this will provide a firm foundation for further quantitative and qualitative analysis.

Four follow-on actions would complement the work undertaken for this report, and all the expert work published around the world that this report builds upon:

1. **Integration** of the potential linkages between all the sources of supply and demand for hydrogen in energy scenarios that can explore the complex trade-offs between competing energy pathways. A key challenge is the incorporation of learning as technologies are deployed in multiple sectors and under multiple levels of governance (from municipal to national and regional) in parallel. Understanding infrastructure needs of different pathways will also be central to decision making.
2. **Development** of a reliable "go-to" resource for tracking progress with policies, technologies and cost trends. Without accurate information on costs and deployment, learning rates will remain highly uncertain and disagreements between analysts will persist. Both public- and private-sector reporting mechanisms could be put in place to the benefit of all parties.
3. **Co-ordination** and enhancement of the existing and planned multilateral initiatives in this area, including the IEA Technology Collaboration Programmes for Hydrogen and Advanced Fuel Cells, IPHE, Hydrogen Energy Ministerials, the Clean Energy Ministerial, Mission Innovation and industry associations.
4. **Creation** of forums for knowledge exchange between national, state-level and local governments, together with private-sector partners and other key stakeholders. Hydrogen infrastructure deployment will not be realised without effective partnerships between all those who can provide funds, implement regulation, manage safety and, crucially, engage with local communities.

The IEA plans to continue its cutting-edge analysis on hydrogen beyond this report, including in its role as the co-ordinator of the Clean Energy Ministerial Hydrogen Initiative, launched in May 2019. Any new data and additional analysis (along with assumptions, interactive graphs, tables and maps) will be accessible on the IEA hydrogen web portal – www.iea.org/hydrogen.

What next for governments and industry?

Hydrogen today appears to have a tailwind, with the opportunity to successfully build on this unprecedented momentum. This reports sets out the case for the 2030 time horizon being a critical springboard for wider deployment of clean, affordable hydrogen. Smart policy is needed that builds on dependable uses in industrial applications to drive low-cost and low-carbon hydrogen production on a larger scale, and that in parallel stimulates new sources of demand and connects markets.

The four key value chains covered in this chapter offer opportunities to scale up low-carbon hydrogen supply and demand in the areas where the near-term opportunities look most promising, building on existing industries, infrastructure and policies. The policy recommendations for each of these value chains are specific but not exhaustive, and additional opportunities and challenges are certain to emerge along the way, as with all new technologies.

Taking full advantage of these near-term opportunities could position low-carbon hydrogen to play a critical role in the long-term global effort to achieve a clean, secure, resilient and cost-effective global energy system. In some sectors, hydrogen and hydrogen-based fuels may well be one of very few possible low-carbon alternatives, while in others it may not ultimately make economic sense or require further analysis. Overall, the potentially critical role of hydrogen is increasingly recognised around the world.

To answer the original question posed by this report: yes, there is a strong chance that this time could, in fact, be different and that there is a new and credible pathway to clean, affordable and widespread use of hydrogen in global energy systems, as long as governments, companies and other actors seize these near-term opportunities.

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Abbreviations and acronyms

ASU	air separation unit
ATR	autothermal reforming
BEV	battery electric vehicle
BF-BOF	blast furnace-basic oxygen furnace
CAES	compressed air energy storage;
CAPEX	capital expenditure
CCGT	combined-cycle gas turbine
CH_3OH	methanol
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CCS	carbon capture and storage
CCUS	carbon capture, utilisation and storage
CNG	compressed natural gas
CSA	Central and South America
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DAC	direct air capture
DRI	direct reduced iron
DRI-EAF	direct reduced iron-electric arc furnace
EAF	electric arc furnace
EOR	enhanced oil recovery
FC	fuel cell
FCEV	fuel cell electric vehicle
FLH	fuel load hours
FT	Fischer-Tropsch
G20	Group of Twenty
GHG	greenhouse gas
GT	gas turbine
H_2	hydrogen
HESC	Hydrogen Energy Supply Chain
HVC	high-value chemical
ICE	internal combustion engine
IEA	International Energy Agency
IMO	International Maritime Organization
IPHE	International Partnership for Hydrogen and Fuel Cells in the Economy
ISO	International Organization for Standardization
JUMP	Joint Use Modular Plant
LCFS	low carbon fuel standard
LHV	lower heating value
Li-Ion	lithium-ion
LNG	liquefied natural gas
LOHC	liquid organic hydrogen carrier
LPG	liquefied petroleum gas
MCFC	molten carbonate fuel cell
MCH	methylcyclohexane
MeOH	methanol
N_2	nitrogen
NG	natural gas
NH_3	ammonia

NO_x	nitrogen oxides
OPEX	operational expenditure
PAFC	phosphoric acid fuel cells
PEM	proton exchange membrane
PEMFC	polymer electrolyte membrane fuel cell
PHES	pumped-hydro energy storage
PV	photovoltaic
R&D	research and development
RD&D	research, development and demonstration
RoW	rest of world
rSOEC	reversible solid oxide electrolyser cell
SDS	Sustainable Development Scenario
SMR	steam methane reforming
SOEC	solid oxide electrolysis cell
SOFC	solid oxide fuel cells
US DOE	United States Department of Energy
VLSFO	very low sulphur fuel oil
VRE	variable renewable energy
WACC	weighted average cost of capital
WAG	works-arising gases
WGS	water-gas-shift
w/	with
w/o	without
ZEV	zero-emission vehicle

Units of measure

bbl	barrel
bbl/d	barrels per day
bcm	billion cubic metres
bcm/yr	billion cubic metres per year
cm/s	centimetres per second
gCO_2	gram of carbon dioxide
gCO_2/kWh	grams of carbon dioxide per kilowatt hour
GJ	gigajoule
Gt/yr	gigatonnes per year
$GtCO_2$	gigatonne of carbon dioxide
$GtCO_2$/yr	gigatonnes of carbon dioxide per year
GW	gigawatt
GWh	gigawatt hour
h	hour
kb/d	thousand barrels per day
kg	kilogram
$kgCO_2$	kilogram of carbon dioxide
kgH_2	kilogram of hydrogen
kg/m_3	kilograms per cubic metre
km	kilometre
ktH_2	kilotonne of hydrogen
ktH_2/yr	kilotonnes of hydrogen per year
kW	kilowatt
kW_e	kilowatt electrical
kWh	kilowatt hour
kWh-eq	kilowatt hour equivalent
kW_{H2}	kilowatt of hydrogen
m^2	square metre
m^2/kW_e	square metre per kilowatt electrical

m^3	cubic metre
mb/d	million barrels per day
MBtu	million British thermal units
MJ	megajoule
MJ/L	megajoules per litre
MJ/kg	megajoules per kilogram
Mt	million tonnes
Mt/yr	million tonnes per year
MtH_2	million tonnes of hydrogen
MtH_2/yr	million tonnes of hydrogen per year
$MtCO_2$/yr	million tonnes of carbon dioxide per year
Mtoe	million tonnes of oil equivalent
Mtoe/yr	million tonnes of oil equivalent per year
MW	megawatt
MW_e	megawatt electrical
MWh	megawatt hour
MW_{H2}	megawatts of hydrogen
t	tonne
tCO_2	tonne of carbon dioxide
tCO_2/t	tonne of carbon dioxide per tonne
tCO_2/tH_2	tonne of carbon dioxide per tonne of hydrogen
tH_2	tonne of hydrogen
tH_2/yr	tonnes of hydrogen per year
tNH_3	tonne of ammonia
tpd	tonnes per day
TWh	terawatt hour
TWh/yr	terawatt hours per year

Report prepared by the IEA for the G20, Japan

Japan's G20 presidency 2019 asked the International Energy Agency to analyse progress in G20 countries and beyond to provide a firm foundation for high-level discussions of hydrogen, based on common a understanding of its status and prospects. The Japan presidency, which began on 1 December 2018 and runs through 30 November 2019, has placed a strong focus on innovation, business and finance.[1] In the areas of energy and the environment, Japan wishes to create a "virtuous cycle between the environment and growth", which is the core theme of the G20 Ministerial Meeting on Energy Transitions and Global Environment for Sustainable Growth in Karuizawa, Japan, 15-16 June 2019.

A first draft report was presented to the 2nd meeting of the G20 Energy Transitions Working Group (ETWG), held through 18-19 April 2019. This final report incorporates feedback and comments submitted during April by the G20 membership, and was shared with the ETWG members.

This final report is cited in "PROPOSED DOCUMENTS FOR THE JAPANESE PRESIDENCY OF THE G20" that was distributed to the G20 Energy Ministers, who convened in Karuizawa on 15-16 June 2019.

This report, prepared as an input for the 2019 G20 Osaka Summit, is an IEA contribution; it is not submitted for formal approval by energy ministers, nor does it reflect the G20 membership's national or collective views. The report lays out where things stand now; the ways in which hydrogen can help to achieve a clean, secure and affordable energy future; and how governments and industry can go about realising its potential. Together with other related information, the report can be found at the IEA hydrogen web portal at https://www.iea.org/topics/hydrogen/.

[1] For an overview of the vision and priorities of the G20 Japan presidency, see www.japan.go.jp/g20japan/.

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