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Global Hydrogen Review 2023

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Abstract

The *Global Hydrogen Review* is an annual publication by the International Energy Agency that tracks hydrogen production and demand worldwide, as well as progress in critical areas such as infrastructure development, trade, policy, regulation, investments and innovation.

The report is an output of the Clean Energy Ministerial Hydrogen Initiative and is intended to inform energy sector stakeholders on the status and future prospects of hydrogen, while also informing discussions at the Hydrogen Energy Ministerial Meeting organised by Japan. Focusing on hydrogen's potentially major role in meeting international energy and climate goals, the Review aims to help decision makers fine-tune strategies to attract investment and facilitate deployment of hydrogen technologies at the same time as creating demand for hydrogen and hydrogen-based fuels. It compares real-world developments with the stated ambitions of government and industry.

This year's report includes a focus on demand creation for low-emission hydrogen. Global hydrogen use is increasing, but demand remains so far concentrated in traditional uses in refining and the chemical industry and mostly met by hydrogen produced from unabated fossil fuels. To meet climate ambitions, there is an urgent need to switch hydrogen use in existing applications to low-emission hydrogen and to expand use to new applications in heavy industry or long-distance transport.

Acknowledgements, contributors and credits

The *Global Hydrogen Review* was prepared by the Energy Technology Policy (ETP) Division of the Directorate of Sustainability, Technology and Outlooks (STO) of the International Energy Agency (IEA). The study was designed and directed by Timur Gül, Chief Energy Technology Officer and Head of the Energy Technology Policy Division. Uwe Remme (Head of the Hydrogen and Alternative Fuels Unit) and Jose Miguel Bermudez Menendez co-ordinated the analysis and production of the report. Laura Cozzi, Dennis Hesseling, Paolo Frankl, Tim Gould, Keisuke Sadamori, Hiro Sakaguchi, and Araceli Fernandez Pales provided valuable, strategic guidance during the report's development process.

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The development of this report benefitted from contributions provided by the following IEA colleagues: Ana Alcalde Bascones, Carl Greenfield, Ilkka Hannula, Luca Lo Re, Jennifer Ortiz, and Nikoo Tajdolat. Lizzie Sayer edited the manuscript while Liselott Fredriksson, Anna Kalista and Per-Anders Widell provided essential support throughout the process.

Thanks also to the IEA Communications and Digital Office for their help in producing the report, particularly to Curtis Brainard, Poeli Bojorquez, Jon Custer, Astrid Dumond, Merve Erdil, Grace Gordon, Jethro Mullen, Isabelle Nonain-Semelin, Julie Puech, Lucile Wall, Therese Walsh and Wonjik Yang.

The work could not have been achieved without the financial support provided by the Governments of Australia, Canada, Germany, and Japan. The following governments have also contributed to the report through their voluntary contribution to the CEM Hydrogen Initiative: Australia, Austria, Canada, Finland, Germany, the European Commission, the Netherlands, Norway, the United Kingdom and the United States.

Special thanks go to the following organisations and initiatives for their valuable contributions: Advanced Fuel Cells Technology Collaboration Programme (TCP), European Patent Office, Hydrogen Council, Hydrogen TCP and the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE).

Peer reviewers provided essential feedback to improve the quality of the report. They include: Nawal Al-Hanaee (Ministry of Energy and Infrastructure, United Arab Emirates); Abdul'Aziz Aliyu (GHG TCP); Laurent Antoni and Noé van Hulst (IPHE); Florian Ausfelder (Dechema); Ruta Baltause, Tudor Constantinescu, Ruud Kempener, Eirik V. W. Lønning and Matthijs Soede (European Commission); Frederic Bauer (Lund University); Prerna Bhargava (Department of Climate Change, Energy, the Environment and Water, Australia); Herib Blanco; Joß Bracker (Federal Ministry for Economic Affairs and Climate Action, Germany); Paula Brunetto (Enel); James Collins (ITM Power); Harriet Culver, Katherine Davis, Lara Hirschhausen and Oliviero Iurkovich (Department for Energy Security and Net Zero, United Kingdom); Caroline Czach, Isabel Murray and Claudie Roy (Natural Resources Canada); Lucie Ducloue (Air Liquide); Alexandru Floristean (Hy24); Daniel Fraile (Hydrogen Europe); Marta Gandiglio (Politecnico di Torino); Dolf Gielen (World Bank); Celine Le Goazigo (WBCSD); Stefan Gossens (Schaeffler AG); Emile Herben (Yara); Marina Holgado (Hydrogen TCP); Marius Hörnschemeyer (DENA); Ruben Hortensius, Sanne van Santen and Anouk Zandbergen (Ministry of Economic Affairs and Climate Policy, the Netherlands); Shunsuke Inui and Wataru Kaneko (Ministry of Economy, Trade and Industry, Japan); Leandro Janke (Agora Energiewende); Adam Karl (AECOM); Ilhan Kim (Ministry of Trade, Industry and Energy, Korea); Marcos Kulka (Chile Hydrogen Association); Subhash Kumar (ACME); Leif Christian Kröger (thyssenkrupp nucera); Martin Lambert (Oxford Institute for Energy Studies); Wilco van der Lans (Port of Rotterdam Authority); Kirsten McNeill (Sunfire); Jonas Moberg (Green Hydrogen Organisation); Susana Moreira (H2Global); Pietro Moretto (JRC); Motohiko Nishimura, Taku Hasegawa, Aya Saito and Tomoki Tominaga (Kawasaki Heavy Industries, Ltd.); Daria Nochevnik (Hydrogen Council); Maria Teresa Nonay Domingo (Enagás); Koichi Numata (Toyota); Cédric Philibert (Independent consultant); Mark Pickup (Ministry of Business, Innovation & Employment, New Zealand); Nicolas Pocard (Ballard); Joris Proost (UCLouvain Belgium); Andrew Purvis (World Steel Association); Noma Qase (Department of Mineral Resources, South Africa); Agustín Rodriguez (Topsoe); Xavier Rousseau (Snam); Sunita Satyapal and Neha Rustagi (Department of Energy, United States); Julian Schorpp (Thyssenkrupp Steel Europe); Ángel Landa Ugarte (Iberdrola); Derek Wissmiller (GTI Energy); and Marcel Weeda (TNO).

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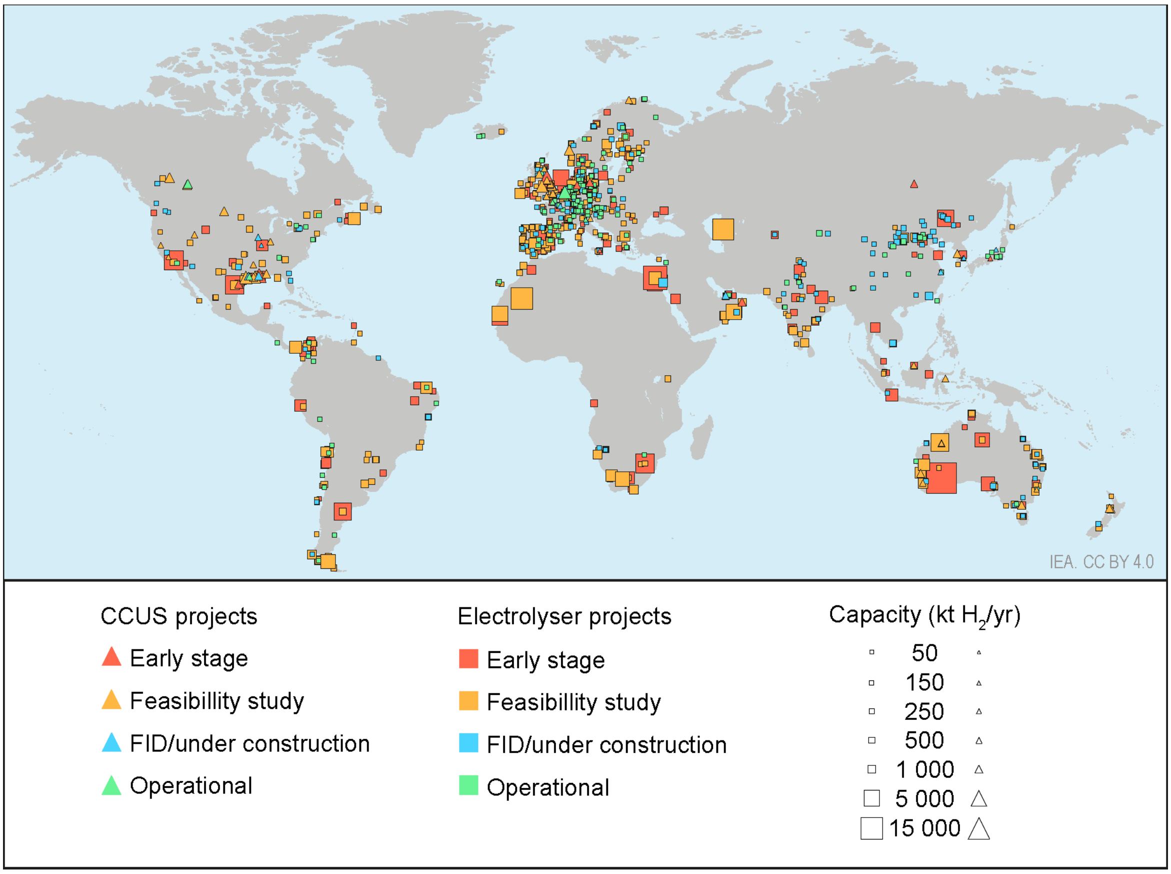
Executive summary

Low-emission hydrogen production can grow massively by 2030 but cost challenges are hampering deployment

The number of announced projects for low-emission hydrogen production is rapidly expanding. Annual production of low-emission hydrogen could reach 38 Mt in 2030, if all announced projects are realised, although 17 Mt come from projects at early stages of development. The potential production by 2030 from announced projects to date is 50% larger than it was at the time of the release of the IEA's Global Hydrogen Review 2022. Only 4% of this potential production has at least taken a final investment decision (FID), a doubling since last year in absolute terms (reaching nearly 2 Mt). Of the total, 27 Mt are based on electrolysis and low-emission electricity and 10 Mt on fossil fuels with carbon capture, utilisation and storage.

Figure ES.1 Map of announced low-emission hydrogen production projects



Note: Map includes also announced projects starting after 2030.
Source: IEA Hydrogen Projects database.

After a slow start, China has taken the lead on electrolyser deployment. In 2020, China accounted for less than 10% of global electrolyser capacity installed for dedicated hydrogen production, concentrated in small demonstration projects. In 2022, installed capacity in China grew to more than 200 MW, representing 30% of global capacity, including the world's largest electrolysis project (150 MW). By the end of 2023, China's installed electrolyser capacity is expected to reach 1.2 GW – 50% of global capacity – with another new world record-size electrolysis project (260 MW), which started operation this year. China is poised to further cement its leading position in electrolyser deployment: the country accounts for more than 40% of the electrolysis projects that have reached FID globally.

Equipment and financial costs are increasing, putting projects at risk and reducing the impact of government support for deployment. Inflation is increasing capital and financial costs, threatening the bankability of projects across the entire hydrogen value chain, which are highly capital intensive. For hydrogen produced from renewable electricity, for example, an increase of 3 percentage points in the cost of capital could raise total project cost by nearly one-third. Several projects have revised their initial cost estimates upwards by up to 50%. Inflationary pressures have coincided with a recent fall in natural gas prices, particularly in Europe, and with supply chain disruptions that affected project timelines. This means that announced government funding will support a smaller number of projects than could be expected previously, as greater investment is needed to close the cost gap between low-emission hydrogen and unabated fossil fuels-based hydrogen.

Governments have started to make funding available to support the first large-scale projects, but slow implementation of support schemes is delaying investment decisions. North America and Europe have taken the lead in implementing initiatives to encourage low-emission hydrogen production. Large amounts of government funding are being made available through schemes such as the US Hydrogen Production Tax Credit, the EU Important Projects of Common European Interest and the UK Low Carbon Hydrogen Business Model. However, the lengthy time lags between the announcement of the schemes and the moment at which funds are made available to project developers is delaying project execution, and even putting projects at risk. This has been aggravated by the lack of clarity about regulation, which has only very recently been resolved in some jurisdictions.

Electrolyser manufacturers have announced ambitious expansion plans. Manufacturers have announced that around 14 GW of manufacturing capacity are available today, half of which is in China. Electrolyser production in 2022 is estimated to be just over 1 GW. Manufacturers have announced plans for further expansion, aiming to reach 155 GW/year of manufacturing capacity by 2030, but only 8% of this capacity has at least reached FID. Realising manufacturers' ambitious plans will depend on solid demand for electrolysers, which today is highly uncertain. Such uncertainty is already resulting in delays to these expansion plans, some of which are being put on hold.

Efforts to stimulate low-emission hydrogen demand are lagging behind what is needed to meet climate ambitions

Hydrogen demand reached a historical high in 2022, but it remains concentrated in traditional applications. Global hydrogen use reached 95 Mt in 2022, a nearly 3% increase year-on-year, with strong growth in all major consuming regions except Europe, which suffered a hit to industrial activity due to the sharp increase in natural gas prices. This global growth does not reflect a success of policy efforts to expand the use of hydrogen, but rather is linked to general global energy trends. Demand remains concentrated in industry and refining, with less than 0.1% coming from new applications in heavy industry, transport or power generation. Low-emission hydrogen is being taken up very slowly in existing applications, accounting for just 0.7% of total hydrogen demand, implying that hydrogen production and use in 2022 was linked to more than 900 Mt of CO_2 emissions. Prospects are better in industry, particularly for ammonia production, with refining lagging behind.

Measures to stimulate low-emission hydrogen use have only recently started to attract policy attention and are still not sufficient to meet climate ambitions. Government action has been focused on supporting low-emission hydrogen production, with less attention to the demand side. The sum of all government targets for low-emission hydrogen production accounts for 27-35 Mt today, but targets for creating demand account for just 14 Mt, less than half of which is focused on existing hydrogen uses. Even if these targets are met, they represent only one-fifth of the low-emission hydrogen use in the Net Zero Emissions by 2050 Scenario (NZE Scenario) by 2030. Without robust demand, producers of low-emission hydrogen will not secure sufficient off-takers to underpin large-scale investments, jeopardising the viability of the entire low-emission hydrogen industry.

The private sector has started moving to adopt low-emission hydrogen through off-take agreements, but efforts remain at very small scale. Companies have signed off-take agreements for up to 2 Mt of low-emission hydrogen, although more than half are preliminary agreements with non-binding conditions. Some companies are developing projects for an additional 3 Mt of low-emission hydrogen production for their own use, without the need for off-take agreements. But even with the addition of these quantities, low-emission hydrogen use is still far from what is needed to meet climate goals.

International co-operation initiatives can help to aggregate demand for low-emission hydrogen, but demand signals from these initiatives are unclear. Governments and companies have launched a series of co-operation initiatives to foster deployment of low-emission technologies, including hydrogen. Based on the commitments made by these initiatives, they could create 0.8-3 Mt of low-emission hydrogen demand by 2030. However, the real impact of their pledges remains to be seen. These initiatives predominantly target new applications of hydrogen, and there is no dedicated coalition targeting the chemical and refining sectors, which are better placed to adopt low-emission hydrogen at scale in the short term.

Scaling up low-emission hydrogen use is also key to enabling the nascent hydrogen trade. International trade of hydrogen and hydrogen-based fuels is expected to be an important feature of a net zero future. In the NZE Scenario, more than 20% of demand for merchant hydrogen and hydrogen-based fuels is internationally traded by 2030. Based on announced export-oriented projects, 16 Mt of hydrogen equivalent could be exported all around the world by 2030, but only three projects have reached FID. The realisation of these announced trade projects will depend on securing off-takers for the long run, as well as the implementation of certification schemes and deployment of the necessary infrastructure. Progress on infrastructure is moving slowly. There have been announcements for around 50 terminals and port infrastructure for hydrogen and hydrogen-based fuels, and for up to 5 TWh of underground storage capacity aiming to be operative by 2030, but none of them has reached FID. Infrastructure projects typically have very long lead times, so it is critical to start developing them now to have a chance of them being available by 2030.

Transforming momentum around hydrogen into deployment remains a struggle

Political momentum behind low-emission hydrogen remains strong but deployment is not taking off. A total of 41 governments now have a hydrogen strategy in place and some of the early movers are updating their original strategies, raising ambitions. There is consensus that low-emission hydrogen is a key opportunity for decarbonising sectors where emissions are hard to abate. The energy crisis arising from Russia's invasion of Ukraine has also turned a spotlight on the role that low-emission hydrogen can play in enhancing energy security. In addition, several major economies have recently adopted new industrial strategies, in which hydrogen technologies play a key part. Government policies and private sector plans are translating into an expanding flow of capital into the low-emission hydrogen sector. However, despite this momentum, low-emission hydrogen still accounts for less than 1% of global hydrogen production and use, and will need to grow more than 100-fold by 2030 to get in line with the NZE Scenario.

Regulation and certification remain key barriers to adoption, but strong international co-operation can be crucial to finding solutions. Several countries have started putting in place regulations on hydrogen's environmental attributes and developing associated certification schemes. These have some commonalities, but also significant divergences, which may lead to market fragmentation. Intergovernmental forums like the G7 and the G20 have recognised this risk and committed to work towards mutual recognition of certificates, which can facilitate market and regulatory interoperability. Referring to the emissions intensity of hydrogen production in regulation and certification – based on agreed methodology – can enable mutual recognition.[1]

Governments need stronger policy action on multiple fronts to tap into the opportunity that low-emission hydrogen offers. Low-emission hydrogen can be an opportunity for countries to boost their economies for the future by creating industries along the supply chains of hydrogen technologies. In the Stated Policies Scenario, the market size of the low-emission hydrogen sector rises from USD 1.4 billion today to USD 12 billion by 2030, equivalent to the spending on offshore wind in Europe in 2022. Increasing ambitions in line with the NZE Scenario could expand the market size up to USD 112 billion, roughly the size of the market for rooftop solar PV installations in the Asia Pacific region in 2022. However, there are challenges around the expansion of technology manufacturing, as well as for creating demand and securing off-takers for low-emission hydrogen production. These challenges are to be expected in a sector that needs to build up complex value chains, but have been exacerbated by inflation, the fall in fossil fuel prices and sluggish policy implementation. Overcoming these challenges requires governments to act across the whole value chain, or progress will be disjointed and lead to cancellations and setbacks.

Recommendations

Urgently implement support schemes for low-emission hydrogen production and use

Governments have announced numerous programmes to support first movers, but in most cases, these programmes are not yet implemented, or the funds have not yet been made available. This is hindering investment decisions for planned projects whose economic feasibility depends on public support, a situation that has worsened due to the impacts of inflation. Governments need to urgently implement these programmes and make funding available to enable a scale-up compatible with their decarbonisation ambitions.

[1] See the report Towards hydrogen definitions based on their emissions intensity for more analysis on how emissions intensity can facilitate mutual recognition of certificates.

Take bolder action to stimulate demand creation for low-emission hydrogen, particularly in existing hydrogen uses

Governments must take the lead and implement policies that encourage action in the private sector, combining support measures with regulations (such as quotas or mandates) to require the adoption of low-emission hydrogen in existing applications. These measures can be complemented with technology-neutral regulations in priority sectors where alternative mitigation options exist (such as steel, shipping, aviation, and long-distance road transport), and with public procurement for low-emission and near-zero emission materials and products. Co-ordinated action is needed to unlock the necessary level of demand while facilitating a level playing field, avoiding industry relocation and carbon leakage. The private sector can also contribute by establishing an international co-operation initiative focused on demand aggregation in chemicals or refining, which are best suited to scale up demand in the short term.

Foster international co-operation to accelerate solutions for hydrogen certification and mutual recognition of certificates

Governments should keep moving forward with the implementation of clear regulations and associated certification schemes for hydrogen's environmental attributes. International co-operation needs to be reinforced to prevent lack of alignment between these efforts, which could lead to market fragmentation. Full harmonisation seems impossible in the near term, but governments should work together to enable mutual recognition of certificates, which would allow a certain level of market interoperability. Referring to the emissions intensity of hydrogen production in regulations and certifications, based on a common methodology for determining the emissions, in line with the recommendations of the IEA's report for the 2023 G7 Climate, Energy and Environment Ministerial meeting, Towards hydrogen definitions based on their emissions intensity, can facilitate the mutual recognition of certificates.

Quickly address regulatory barriers, particularly for project licensing and permitting

The presence of a clear and stable regulatory framework must be balanced with a dynamic approach, calibrated to regular market monitoring, trying to make regulatory principles workable to not discourage investments. Governments should work to make licensing and permitting processes as efficient as possible and to improve co-ordination among different authorities involved in the process, to minimise their significant impact on project lead times, particularly for certain infrastructure developments, such as new pipelines, underground storage and import/export terminals.

Support project developers to maintain momentum during the inflationary period and to extend regional reach

Governments can take action with interventions that respond to near-term financial risks including loan guarantees, export credit facilities or public equity investment in projects, to help project developers that are struggling with increases in costs for equipment and capital. In addition, advanced economies need to raise concessional finance - beyond their recent commitments - and boost co-operation to facilitate the development of first-of-a-kind projects in emerging markets and developing economies, including through rapid standardisation of contract templates to overcome the unfamiliarity of parties with this new sector.

Chapter 1. Introduction

Overview

The global energy landscape is undergoing a remarkable shift as the world endeavours to combat climate change and enhance energy security by transitioning to cleaner, more sustainable energy sources. In this context, low-emission hydrogen[2] has emerged as an important tool for decarbonising sectors in which emissions are hard to abate. The recent global energy crisis has also given more impetus to low-emission hydrogen as a means to bolster energy security. As a result, governments have strengthened their commitments to achieve net zero emissions, and low-emission hydrogen has become an integral part of their plans. In addition, some major economies have recently adopted new industrial strategies, with hydrogen technologies as a key element. Yet despite this momentum, there are still significant challenges that must be addressed to unlock the potential of low-emission hydrogen.

This edition of the IEA *Global Hydrogen Review* tracks progress in the hydrogen sector, focusing on the role of low-emission hydrogen as a vital driver of the clean energy transition. By analysing recent developments and identifying areas requiring attention, the report seeks to inform governments, industries and other stakeholders on the path needed to ensure hydrogen can play its role in the transition to a sustainable energy system.

First, we consider the status of hydrogen **use** and **production** today. Global hydrogen use is increasing, but demand remains concentrated in traditional uses in refining and the chemical industry and most production is still based on unabated fossil fuels. Low-emission hydrogen production is yet to take off as a mainstream industry.

Nonetheless, the chapter on **trade and infrastructure** reports some encouraging signs. The number of announced projects keeps growing, and hydrogen trade is gaining momentum. However, progress is still lagging in some areas, notably in hydrogen infrastructure and technology innovation. We then go on to consider the landscape for **investment and innovation**, assessing the impact of inflation on low-emission hydrogen projects. Together with supply chain disruptions, inflation has put some initiatives at risk.

Finally, a chapter on **policy** trends highlights the increasing number of policies and strategies being announced to support scale-up of low-emission hydrogen.

[2] See the Explanatory notes annex for the definition of low-emission hydrogen used in this report.

We also consider new regulations relating to hydrogen's environmental attributes, and the need for international co-operation to ensure certificates are mutually recognised and prevent potential market fragmentation.

As this review demonstrates, scaling up low-emission hydrogen production and use will require co-ordinated action by market players and strong government support across multiple fronts. We examine the instruments and policies needed to create favourable conditions for private sector investment and deployment, and how to address barriers currently hindering project development.

The Hydrogen Initiative

Developed under the Clean Energy Ministerial framework, the Hydrogen Initiative (H2I) is a voluntary multi-governmental initiative that aims to advance policies, programmes and projects that accelerate the commercialisation and deployment of hydrogen and fuel cell technologies across all areas of the economy.

The IEA serves as the H2I co-ordinator to support member governments as they develop activities aligned with the initiative. H2I currently comprises the following participating governments and intergovernmental entities: Australia, Austria, Brazil, Canada, Chile, the People's Republic of China (hereafter "China"), Costa Rica, the European Commission, Finland, Germany, India, Italy, Japan, the Netherlands, New Zealand, Norway, Portugal, Republic of Korea (hereafter "Korea"), Saudi Arabia, South Africa, the United Arab Emirates, the United Kingdom and the United States. Canada, the European Commission, Japan, the Netherlands and the United States co-lead the initiative, while China and Italy are observers.

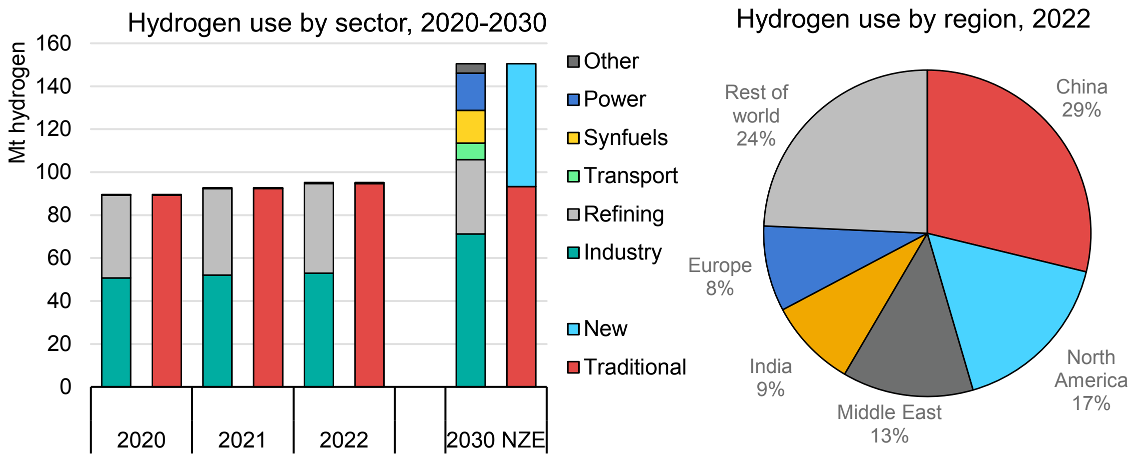
H2I is also a platform to co-ordinate and facilitate co-operation among governments, other international initiatives and the industry sector. H2I has active partnerships with the Breakthrough Agenda, the Hydrogen Council, the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE), the International Renewable Energy Agency (IRENA), the Mission Innovation Clean Hydrogen Mission, the World Economic Forum, the United Nations Industrial Development Organization (UNIDO), and the IEA Advanced Fuel Cells and Hydrogen Technology Collaboration Programmes (TCPs), all of which are part of the H2I Advisory Group and participate in various activities of the H2I. In addition, several industrial partners actively participate in the H2I Advisory Group's biannual meetings, including Ballard, Enel, Engie, Nel Hydrogen, the Port of Rotterdam Authority and thyssenkrupp nucera.

Chapter 2. Hydrogen use

Overview and outlook

Global hydrogen use reached 95 Mt in 2022, a nearly 3% increase from our revised estimate for 2021[3], continuing the growing trend that was only interrupted in 2020 as a consequence of the Covid-19 pandemic and the economic slowdown.

Figure 2.1 Hydrogen use by sector and by region, historical and in the Net Zero Emissions by 2050 Scenario, 2020-2030



Notes: NZE = Net Zero Emissions by 2050 Scenario. "Other" includes buildings and biofuels upgrading.

Hydrogen use continues to grow, but remains concentrated in traditional applications, such as industry and refining.

Hydrogen use has grown strongly in all major consuming regions except Europe. In Europe, hydrogen use suffered a big hit due to reduced activity – particularly in the chemical industry – as a consequence of the sharp increase in natural gas prices resulting from the energy crisis sparked by the Russian Federation's (hereafter "Russia") invasion of Ukraine. Several fertiliser plants reduced their production output or even stopped operations for prolonged periods of the year, reducing hydrogen use by nearly 6% in the region. In contrast, North America and the Middle East observed strong growth (around 7% in both cases), which more than compensated the drop in Europe. In China, use grew more modestly (around

[3] The estimate of hydrogen demand for 2021 has been revised to 93 Mt from the Global Hydrogen Review 2022 (94 Mt), due to adjustments to historic values in underlying datasets. In addition, in this report we are not including estimations of historical use of hydrogen small demands in glassmaking, electronics and metal processing (which accounted for around 1 Mt for 2021 in the estimate of the *Global Hydrogen Review 2022*).

0.5%), but the country remains the largest single consumer of hydrogen by far, accounting for nearly 30% of global hydrogen use (more than double that of the second largest consumer, the United States).

As in previous years, the growth in global hydrogen use is not a result of hydrogen policies, but rather of global energy trends. Practically all of the increase took place in traditional applications (Box 2.1), mainly refining and the chemical sector, and has been met by increasing production based on unabated fossil fuels (see Chapter 3 Hydrogen production). This means that growth has had no benefit for climate change mitigation purposes. The uptake of hydrogen in new applications in heavy industry, transport, the production of hydrogen-based fuels or electricity generation and storage – which is key for the clean energy transition – remains minimal, accounting for less than 0.1% of global demand. In the updated 2023 edition of the IEA's Net Zero Emissions by 2050 Scenario (NZE Scenario), hydrogen use grows by 6% annually until the end of this decade. This implies reaching more than 150 Mt of hydrogen use by 2030, with nearly 40% coming from new applications.[4]

This chapter presents an overview of progress in the uptake of hydrogen in different sectors (including traditional and new applications) and assesses options to increase ambition in demand creation for low-emission hydrogen[5] in the short term.

Box 2.1 Traditional and new applications for hydrogen

Hydrogen is widely used today in refining, the chemical industry (as a feedstock), the steel industry (as a reducing agent) and for special applications in other industries. The evolution of hydrogen use in these applications will be determined by market dynamics in these sectors.

In theory, hydrogen can also be used in a wide range of other applications, as a feedstock or reducing agent, and also as a fuel. Hydrogen has not been used at scale in these applications, either due to its lack of competitiveness with incumbent fossil fuels and with other low-emission technology alternatives, or because end-use technologies have not reached commercial maturity. However, decarbonisation efforts are expected to prompt hydrogen use in some of these new applications, particularly in sectors where emissions are hard to abate and other low-emission technologies are unavailable or very difficult to implement.

[4] The IEA's forthcoming report Net Zero by 2050: A Roadmap for the Global Energy Sector - 2023 Update will present a redesigned NZE Scenario, based on an in-depth, sector-by-sector assessment of the progress and setbacks seen since the release of its landmark report, Net Zero by 2050: A Roadmap for the Global Energy Sector, in May 2021.
[5] See the Explanatory notes annex for the definition of low-emission hydrogen used in this report.

Tracking hydrogen use alone is not sufficient to assess progress on hydrogen adoption, and particularly whether it is happening in the direction and at the pace required for hydrogen to play its role in the clean energy transition. It is important to also track the use of hydrogen by application, with a view to assessing the uptake in new applications. For reporting purposes in the IEA's *Global Hydrogen Review*, we have defined two categories of applications for hydrogen:

- **Traditional applications**, including refining; feedstock to produce ammonia, methanol and other chemicals; and as a reducing agent to produce direct reduced iron (DRI) using fossil-based synthetic gas. This category also includes the use of hydrogen in electronics, glassmaking or metal processing, but these sectors use very small quantities of hydrogen (around 1 Mt per year) and are not included in our tracking.
- Potential **new applications**, such as the use of hydrogen as a reducing agent in 100%-hydrogen DRI, transport, production of hydrogen-based fuels (such as ammonia or synthetic hydrocarbons), biofuels upgrading, high-temperature heating in industry, and electricity storage and generation, as well as other applications in which hydrogen use is expected to be very small due to the existence of more efficient low-emission alternatives.

Refining

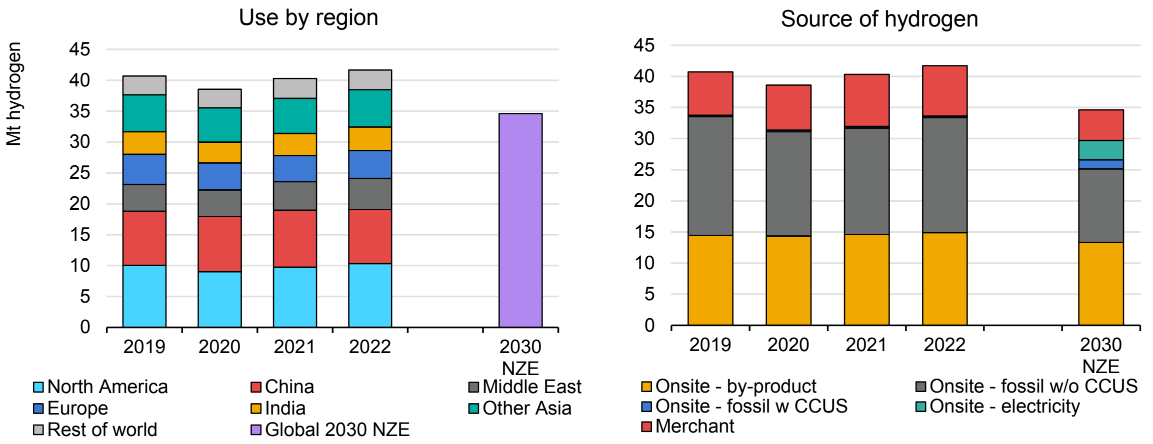
Hydrogen use in refining reached more than 41 Mt in 2022, surpassing its historical maximum from 2018. The largest increase in year-on-year demand came from North America and the Middle East, together accounting for more than 1 Mt, or around three-quarters of global growth in 2022 (Figure 2.2). China was the only major refining region that reduced its demand for hydrogen (around 0.5 Mt) due to a decrease in refinery throughput as a consequence of extensive pandemic-related mobility restrictions.

About 80% of the hydrogen used in refineries was produced onsite at the refineries themselves, with around 55% resulting from dedicated hydrogen production and the rest being produced as a by-product from different operations, such as naphtha crackers. Less than 1% of the hydrogen used in refineries in 2022 was produced using low-emission technologies. The remaining 20% of hydrogen used was sourced as merchant hydrogen,[6] produced externally, and mostly from

[6] Merchant hydrogen sourced by refineries is typically produced in plants very close to the refinery, and sometimes even in the same location, but in plants operated by another company, given that hydrogen is not a global commodity today.

unabated fossil fuels. The production of hydrogen for use in refining resulted in 240-380 Mt CO_2 emitted to the atmosphere in 2022.[7]

Figure 2.2 Hydrogen use by region and source of hydrogen for refining, historical and in the Net Zero Emissions by 2050 Scenario, 2019-2030



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Notes: NZE = Net Zero Emissions by 2050 Scenario. Fossil w/o CCUS = fossil fuels without carbon capture, utilisation and storage; Fossil w CCUS = fossil fuels with carbon capture, utilisation and storage. Onsite refers to the production of hydrogen inside refineries, including dedicated captive production and as a by-product of catalytic reformers.

Hydrogen use in refining reached a new record in 2022, but the fall in demand for oil products required to align with the NZE 2050 Scenario would reverse this trend.

Meeting the requirements of the NZE Scenario necessitates a reversal in the trend towards increasing demand for oil products, which will in turn result in lower hydrogen use in refining. Consequently, the use of hydrogen in refining is less than 35 Mt by 2030 in the NZE Scenario. In addition, a larger share of the hydrogen used in refining is met by low-emission hydrogen, which accounts for more than 15% of hydrogen use in 2030 in the NZE Scenario.

The use of low-emission hydrogen in refining can offer an accessible route to create large demand for low-emission hydrogen and facilitate the scale-up of production, given that it involves a like-for-like substitution rather than a fuel switch. However, use of low-emission hydrogen in refineries has been limited to date, and is progressing slowly as a consequence of its higher production costs when compared with hydrogen produced from unabated fossil fuels (see Chapter 3 Hydrogen production) and the lack of policy action to promote its adoption (see Creating demand for low-emission hydrogen). In 2022, around 250 kt of low-emission hydrogen were used in refineries, practically the same amount as in 2021, given that only a couple of small electrolysis pilot projects (2.4 MW and

[7] The range reflects different emission allocation of by-product hydrogen production. This excludes upstream and midstream emissions for fossil fuel supply.

50 kW of installed capacity) started operating in the year (Figure 2.3). Almost all the low-emission hydrogen used in refining in 2022 was produced in four facilities using fossil fuels with CCUS that were already in operation in refineries in Canada and the United States[8].

An increase in the use of low-emission hydrogen in refining can be expected in 2023. In July, Sinopec put into operation the world's largest electrolysis plant in Kuqa, China, (260 MW), which will produce 20 kt of low-emission hydrogen to supply Tahe refinery. However, there are only a limited number of announced projects aiming to produce low-emission hydrogen in refineries to replace hydrogen produced from unabated fossil fuels. If all the announced projects are realised on time, 1.3 Mt of low-emission hydrogen will be produced and used in refineries by 2030, with around 1.1 Mt being produced from fossil fuels with CCUS and 0.2 Mt from electrolysis.[9] This represents an increase of around 6% compared to the potential production coming from projects announced when the Global Hydrogen Review 2022 was released. Most of this increase is from projects aiming to produce hydrogen from fossil fuels with CCUS. The increase from the very few new announcements by projects aiming to produce hydrogen through electrolysis was nearly cancelled out entirely by pauses in projects that had previously been announced.[10]

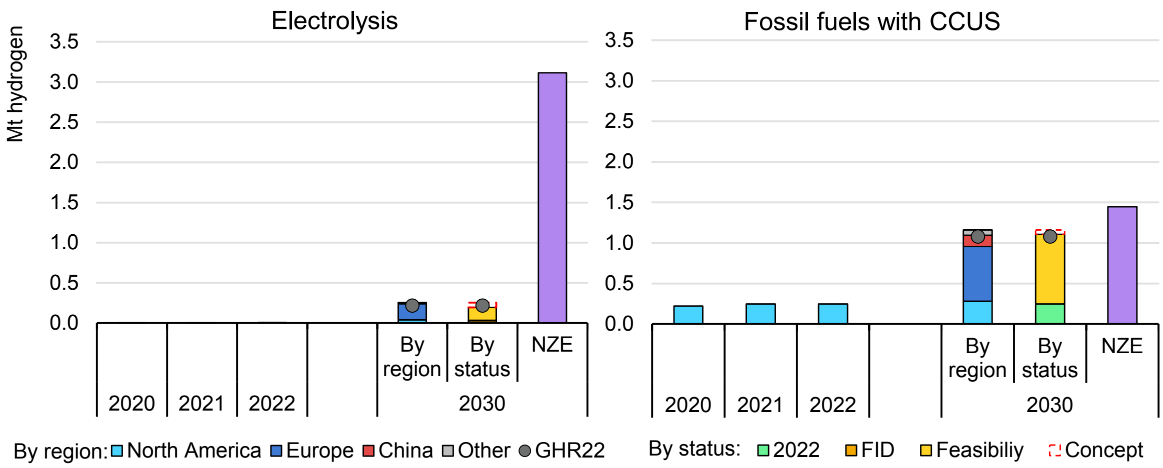
As noted above, the use of merchant hydrogen in refineries is a common practice today and could provide an alternative route to increase the supply of low-emission hydrogen in refineries. This option is being explored by refinery operators and some off-take agreements have already been signed, such as between Vertex Hydrogen and Essar Oil to use hydrogen produced from fossil fuels with CCUS in the Stanlow refinery (United Kingdom). From an analysis of announced projects, we estimate that an additional 0.7 Mt of low-emission hydrogen could be supplied to refineries by 2030.[11]

In the NZE Scenario, more than 4 Mt of low-emission hydrogen are produced and used in refineries by 2030, with around two-thirds produced from electrolysis and low-emission electricity, and one-third from fossil fuels with CCUS. Announced projects therefore meet only around 25% of the NZE Scenario's requirements. The gap with the NZE Scenario is significantly larger in the case of announced projects to produce hydrogen from electrolysis, which meet less than 10% of the NZE requirements. In the case of fossil fuels with CCUS, announced projects account

[8] There are two more facilities in operation in France and the Netherlands, but these produce hydrogen from fossil fuels with CCU, which is not considered as low-emission hydrogen for the purpose of this report.
[9] This could increase to 1.4 Mt (1.15 Mt from fossil fuels and CCUS and 0.25 Mt from electrolysis) with the inclusion of projects at a very early stage of development, e.g. only a co-operation agreement among stakeholders has been announced.
[10] Argus direct (2023), Phillips 66, Orsted pause UK green hydrogen plan.
[11] This could increase to 1 Mt with the inclusion of projects at a very early stage of development, e.g. only a co-operation agreement among stakeholders has been announced.

for around three-quarters of the NZE needs. Moreover, the use of fossil fuels with CCUS in refineries can count on an important head start since projects operating today are already able to meet 15% of the onsite production from fossils with CCUS in the NZE Scenario requirements.

Figure 2.3 Onsite production of low-emission hydrogen for refining by technology, region and status, historical and from announced projects, 2020-2030



Notes: CCUS = carbon capture, utilisation and storage; FID = projects that have at least taken a final investment decision; GHR 2022 = Global Hydrogen Review 2022; NZE = Net Zero Emissions by 2050 Scenario. Only planned projects with a disclosed start year of operation are included. GHR 2022 shows the estimated production of low-emission hydrogen from projects that were included in IEA Hydrogen Projects Database as of August 2022.
Source: IEA Hydrogen Projects , (Database, October 2023 release).

Based on announced projects, 1.3 Mt of low-emission hydrogen could be produced in refineries by 2030, meeting one-quarter of low-emission onsite production needs in the NZE Scenario.

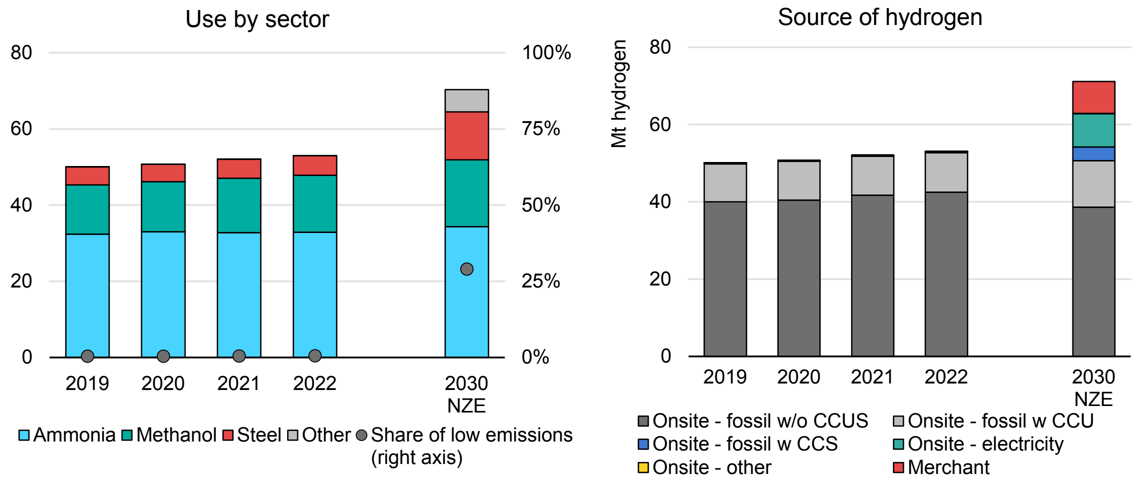
In terms of maturity, around 10% of the announced projects to produce hydrogen from electrolysis to be used in refining have at least taken a final investment decision (FID), whereas no FIDs have been taken for projects to produce hydrogen from fossil fuels with CCUS. As last year, Europe remains the region with the most projects, followed by North America and China.

Industry

Of the 53 Mt of hydrogen used in industry in 2022, about 60% was for ammonia production, 30% for methanol and 10% for DRI in the iron and steel subsector (Figure 2.4). Virtually all hydrogen used in industry is produced from unabated fossil fuels in the same facilities as where it is used. Carbon capture is a common practice in some industry sub-sectors, although most of the 140 Mt of CO_2 captured is used for other industrial applications (such as urea production) and ends up being released, with only a handful of projects storing CO_2 underground.

As a result, industrial hydrogen production was responsible for 680 Mt of CO_2 emissions in 2022, up 2% from 2021.[12]

Figure 2.4 Hydrogen use in industry by subsector and by region and source of hydrogen, historical and in the Net Zero Emissions by 2050 Scenario, 2019-2030



Notes: DRI = Direct Reduced Iron; Fossil w/ CCS = fossil fuels with carbon capture and storage; Fossil w/ CCU = fossil fuels with carbon capture and use; Fossil w/o CCUS = fossil fuels without carbon capture, utilisation and storage; NZE = Net Zero Emissions by 2050 Scenario. Ammonia and methanol exclude fuel applications. 'Other' includes dedicated hydrogen production for high-temperature heat applications.

Sources: IEA analysis based on data from International Fertilizer Association, World Steel Association and Wood Mackenzie.

Hydrogen use in industry increased 2% in 2022 to reach 53 Mt, mostly concentrated in ammonia, methanol and steel production, but a 4% annual growth rate would be necessary to align with the NZE Scenario.

Global hydrogen use in industry in 2022 increased by 2% compared with 2021, driven by global demand for ammonia rising by 0.4%, for methanol by 5% and for DRI by 4%, although growth rates were lower than the average of the previous years. China remains the main consumer of hydrogen in industrial applications, with 35% of global industrial use, followed by the Middle East (14%), North America (10%) and India (9%). Europe was the only major consuming region where hydrogen use in industry fell in 2022, as a consequence of the energy crisis sparked by Russia's invasion of Ukraine. Hydrogen use in industry in Europe decreased 18% in 2022, largely due to a 20% decrease in activity in the ammonia sector, which was particularly impacted by the conflict. At their peak in mid-2022,

[12] This includes direct emissions from hydrogen production and around 290 Mt of CO_2 utilised in the synthesis of urea and methanol, the majority of which is later emitted. This excludes upstream and midstream emissions for fossil fuel supply.

global ammonia prices had increased six-fold compared to the 2020 average. However, prices declined during the first half of 2023, and have now returned to their pre-pandemic level.

In the NZE Scenario, hydrogen use in industry grows to 70 Mt by 2030. Meeting this need would require a 4% annual increase in production, compared to just 2% over the past 4 years. Furthermore, to meet emission reduction objectives, about one-third of industrial hydrogen production capacity needs to be low-emission by 2030, which would require most of the new capacity to be low-emission, as well as retrofits to some existing stock.

Beyond traditional applications in the chemical and steel sectors, hydrogen use also increases in new industrial applications, particularly 100%-hydrogen DRI and high-temperature heating, which account for 16% of global demand in industry by 2030.

Low-emission hydrogen production in industrial plants in 2022 was about 285 kt, up from 240 kt in 2021. More than 90% of this capacity relies on fossil fuels with CCUS with installations spread across North America, the Middle East and China. There has been no significant progress in production of hydrogen from electrolysis since the publication of the GHR 2022, with only three relatively small projects coming online in 2023, one in Spain (8 MW of electrolysis to replace natural gas with hydrogen), one in Sweden (17 MW of electrolysis for heating steel prior to rolling) and one in India (5 MW of electrolysis for methanol production[13]).

However, the near-term outlook is positive, as projects able to produce more than 600 kt of low-emission hydrogen are already under construction or have taken an FID. The vast majority are concentrated in Europe (40%), China (28%) and Middle East (24%). The most noteworthy developments since the release of the GHR 2022 are:

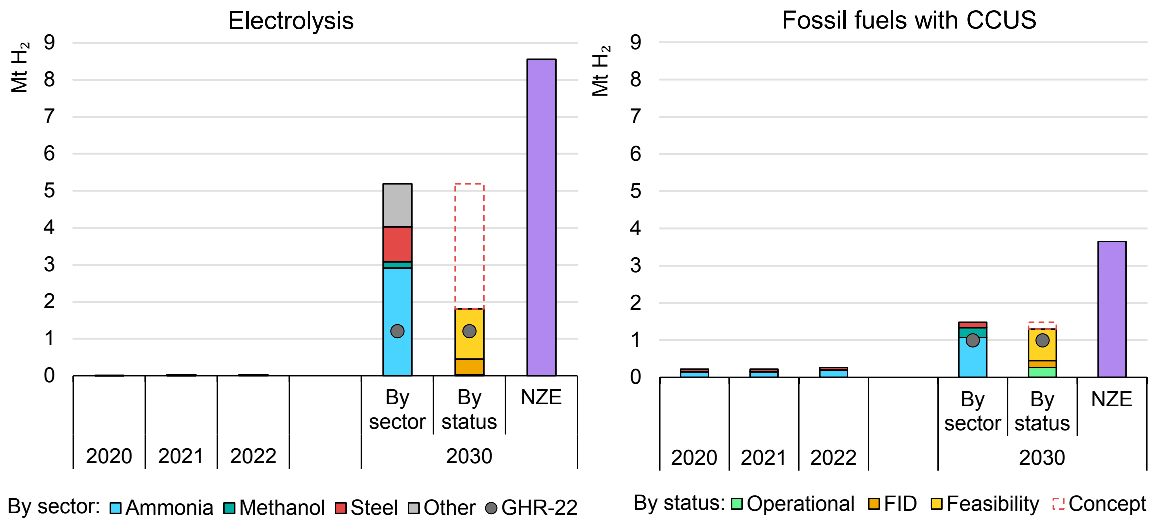
- The Hydrogen Energy Metallurgical Demonstration (China) to produce 390 kt of ammonia using electrolysis and renewable electricity, which started construction in April 2023 and aims to begin operation in 2025.
- A project from OCI aiming to capture 450 kt of CO_2 annually from its Iowa (United States) ammonia plant.
- The first project of H2 Green Steel in Boden (Sweden) which will install between 700 and 800 MW of electrolysers to produce more than 100 kt of hydrogen required annually for its steel production.
- The Hygenco JSL plant (India) which should open in late 2023 and will be the first steel plant using hydrogen from electrolysis and renewable electricity for the annealing process in the country.

[13] Platts Hydrogen Daily (2023), INTERVIEW: NTPC Renewables set to place 1 GW of electrolyzer orders by 2026-27.

Over the past year, numerous additional projects were announced, increasing the expected low-emission hydrogen production from fossil fuels with CCUS by 30% and from electrolysis by 50% (Figure 2.5), thus reaching 1.3 Mt and 1.8 Mt of hydrogen production by 2030, respectively[14]. Some of the newly announced projects include:

- Dow Stade (Germany), which plans to use around 40 kt of electrolytic hydrogen to produce 200 kt of methanol annually.
- Plug Power Kristinestad (Finland), which will install 1 GW of electrolyser capacity to supply a steel DRI plant with about 85 kt of hydrogen per year.
- Yara Sluiskil plant (Netherlands), which projects capturing 800 kt of CO_2 per year from ammonia production.

Figure 2.5 Onsite production of low-emission hydrogen for industry applications by technology and status, historical and from announced projects, 2020-2030



Notes: CCUS = carbon capture, utilisation and storage; FID = final investment decision; GHR-22 = Global Hydrogen Review 2022; NZE = Net Zero Emissions by 2050 Scenario. Projects explicitly using ammonia or methanol as energy carriers are not included. Only projects with a disclosed start year are included. GHR 2022 shows the estimated production of low-emission hydrogen from projects that were available in the IEA Hydrogen Projects Database as of August 2022.
Source: IEA analysis based on data from the International Fertilizer Association and IEA Hydrogen Projects , (Database, October 2023 release).

Announced projects for the production of low-emission hydrogen in the industrial sector can reach 3 Mt by 2030, roughly one-quarter of low-emission onsite production needs in the NZE Scenario.

[14] This could increase to a combined 6.7 Mt if projects at a very early stage of development are included, e.g. projects for which only a co-operation agreement among stakeholders has been announced.

Nonetheless, to align with the net zero emissions target, the production of low-emission hydrogen from electrolysis using renewable electricity and fossil fuels with CCUS in the industry sector needs to reach 8.6 and 3.5 Mt of hydrogen, respectively, almost quadrupling the production potential of the current project pipeline.

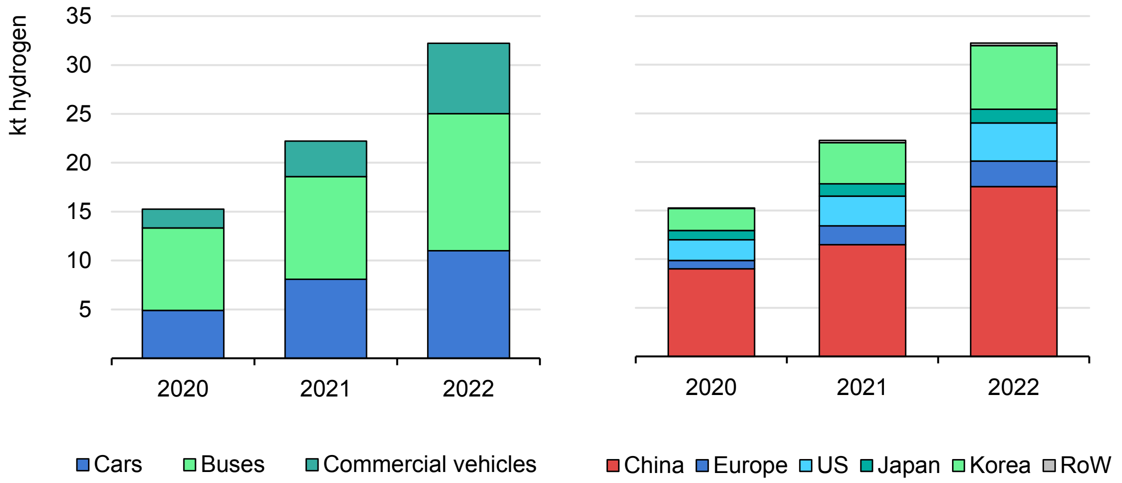
Besides onsite hydrogen production, a significant number of projects aim to produce merchant hydrogen for delivery to industrial consumers. Merchant hydrogen projects can have certain advantages, such as partnering with multiple industrial clients to spread risk, but transport infrastructure is required. We estimate that these projects could supply an additional 0.7 Mt of hydrogen to industrial consumers by 2030 if they can secure off-takers for all their potential production. Some key merchant hydrogen projects include:

- A project in Ordos (China), where Sinopec is building solar, wind and electrolyser capacity to supply 30 kt of hydrogen per year to nearby chemical industries.
- The Catalina Project (Spain), which aims to install 1.1 GW of renewable capacity and 500 MW of electrolysers in 2027 to supply around 40 kt of hydrogen annually to an ammonia plant through a dedicated 221 km pipeline.
- The HyDeal project (Spain), which is developing 4.8 GW of solar and 3.3 GW of electrolyser capacity by 2030 to supply hydrogen to steel and ammonia producers.
- The NorthH$_2$ Project (Netherlands), which targets an electrolyser capacity of 1 GW in 2027 and 4 GW by 2030 to supply more than 300 kt of hydrogen to industries across the region.

Transport

Hydrogen use in road transport increased by around 45% in 2022 compared to 2021 (Figure 2.6), albeit from a relatively low starting point. Fuel cell electric vehicles (FCEVs) saw the earliest successes in terms of vehicle sales, in the car and bus segments, but as heavy-duty fuel cell truck sales increase, their share of total consumption is increasing rapidly. China's focus on heavy-duty vehicles, and outsized role in the deployment of fuel cell trucks, means that although only 20% of all FCEVs are in China, they consume more than half of the hydrogen used in road transport.

Figure 2.6 Hydrogen consumption in road transport by vehicle segment and region, 2020-2022



Notes: RoW = Rest of World; US = United States. Commercial vehicles include light commercial vehicles and medium- and heavy-duty trucks. Assumptions on annual mileage and fuel economy have been updated to match the IEA Global Energy and Climate Model.

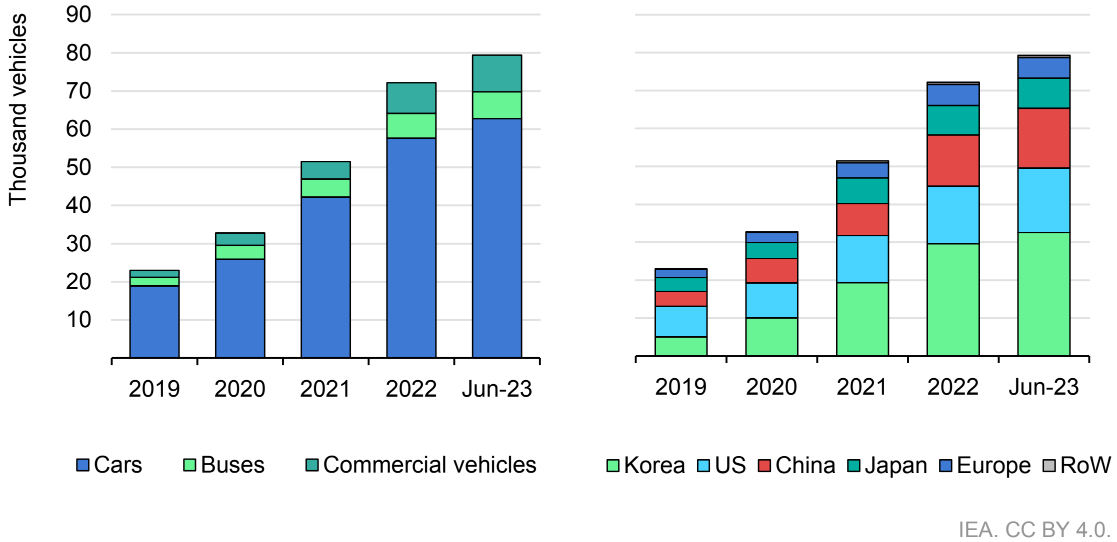
Hydrogen use in road transport increased by around 45% in 2022, albeit from a low base, driven mainly by increased use from heavy-duty vehicles.

The vast majority of hydrogen use in transport will likely remain in the road sector for years to come, but rail is also adding to hydrogen consumption as hydrogen trains are being trialled and adopted along more routes. In addition, several fuel cell ferries are beginning operation in 2023, which will further diversify hydrogen use for transport applications. Orders for ammonia- and methanol[15]-ready vessels could also result in additional hydrogen use for shipping in the coming years if these technologies reach commercial maturity.

In the NZE Scenario, the use of synthetic kerosene and even the direct use of hydrogen as an aviation fuel in later years add to hydrogen use in transport. To get on track with the NZE Scenario, it will be important to accelerate the adoption of hydrogen and hydrogen-based fuels and advance technologies that are today still pre-commercial. In the NZE Scenario in 2030, almost 8 Mt of hydrogen is used directly in transport, mostly in the road (50%) and shipping (45%) sectors. In addition, around 8 Mt of hydrogen are used for the production of ammonia and synthetic fuels for their use in shipping and aviation.

[15] Low-emission methanol can be biomethanol or synthetic methanol (e-methanol), but only the latter contributes to hydrogen demand.

Figure 2.7 Fuel cell electric vehicle stock by segment and region, 2019-2023



Notes: RoW = Rest of World; US = United States. Includes data until June 2023 for the current year.
Sources: Advanced Fuel Cells Technology Collaboration Programme; Hydrogen Fuel Cell Partnership; Korea's Ministry of Trade, Industry and Energy monthly automobile updates; Chinese vehicle insurance registration data, International Partnership for Hydrogen and Fuel Cells in the Economy and Clean Energy Ministerial Hydrogen Initiative country surveys.

The global fleet of FCEVs is closing in on 80 000, with Korea remaining the major market for cars and China for trucks.

Cars and vans

By the end of 2022, the stock of fuel cell cars and vans exceeded 58 000, an almost 40% increase compared to the previous year, and has reached around 63 000 in the first half of 2023 (Figure 2.7).[16] About 15 000 fuel cell cars were sold in 2022, with Korea representing around two-thirds of that increase. The first half of 2023 saw something of a slowdown in the country, with fewer than 3 000 units sold, compared to almost 4 900 during the same timeframe the previous year, despite government plans to subsidise 16 000 fuel cell cars in 2023. Nevertheless, Korea remains the largest fuel cell car market in the world, with a stock of over 32 000 fuel cell cars as of the first half of 2023. The second largest market is the United States, with around 16 000 fuel cell cars on the road. While Japan is still home to the third largest stock of fuel cell cars, fewer than 1 000 units were sold in the country in 2022, meaning that Europe experienced higher growth with almost 1 500 additions. China added more than 200 fuel cell cars in 2022, which is remarkable given that the country has over the past few years only deployed FCEVs in heavier segments. As of June 2023, China is home to the majority of fuel cell light commercial vehicles, with over 800 units deployed.

[16] The deployment of fuel cell cars remains significantly lower than that of battery electric cars, which reached a global stock of over 18 million in 2022.

Reflecting Korea's dominance in domestic fuel cell car sales, Hyundai's Nexo represented the best-selling fuel cell car (10 000) in 2022; Toyota's Mirai came in second (3 200). Both the SAIC EUNIQ7 and Honda Clarity sold around 200 fuel cell cars in 2022, despite Honda discontinuing production of their fuel cell car in 2021. BMW also began small-series production of the iX5 Hydrogen fuel cell car in 2022, launching their pilot fleet internationally at the beginning of 2023.

More fuel cell light-duty vehicle models are expected to enter the market in the future. Honda has announced a new fuel cell vehicle, based on their CR-V crossover sports utility vehicle (SUV), which will begin production in 2024 in the United States. NamX, a Moroccan start-up, has presented a prototype fuel cell SUV that can be fuelled in part by replaceable hydrogen capsules, with plans to launch in 2026. Kia, Korea's second largest carmaker, aims to release fuel cell cars starting from 2027. Additionally, both Porsche and Toyota have developed prototype hydrogen cars using combustion engines, highlighting their multi-technology approaches. However, FCEVs are very much a minority technology with companies such as Volkswagen focusing instead on battery electric vehicles. The French start-up Hopium had plans to produce a luxury fuel cell sedan to enter the market in 2025, but instead entered receivership in July 2023.

In the light-commercial segment, new entrants First Hydrogen began trialling their "Generation I" fuel cell van in 2023, with plans to launch a second generation vehicle in the coming years. RONN Motor Group has also announced plans to manufacture fuel cell delivery vans, as well as medium-duty trucks. In terms of established names, Ford has announced a fuel cell van trial in the United Kingdom.

Trucks

The stock of fuel cell trucks has grown faster than light-duty vehicles, increasing over 60% in 2022 to bring the total to more than 7 100 by the end of the year. In the first half of 2023, the stock reached more than 8 000.[17] The vast majority of sales took place in China, which now accounts for over 95% of fuel cell trucks globally, driven largely by a more than fivefold increase in heavy-duty fuel cell trucks from the end of 2021 to June 2023 thanks to favourable policy and supporting infrastructure. Fuel cell trucks are also being proven in practical use outside of China, with Hyundai's Xcient accumulating 5 million km in Switzerland since 2020, with operations now also in Germany, Korea and New Zealand. According to CALSTART's Zero-Emission Technology Inventory (ZETI) there were around 20 medium- and heavy-duty fuel cell truck models available in 2022, with a handful additional models planned for 2023.

[17] For comparison, there were around 300 000 battery electric medium- and heavy-duty trucks globally at the end of 2022.

In Europe, there have been a number of announcements for orders of fuel cell trucks, such as from German energy company GP Joule, which ordered 100 Nikola Tre FCEVs (30 to be delivered within 2024); a SINTEF-led H2Accelerate project in which 150 trucks will be deployed in Europe; and H2X Global winning the tender to provide trucks for waste management in Gothenburg, Sweden. Additionally, smaller announcements have come from companies such as Dura Vermeer, and from Scania, which will be delivering fuel cell trucks in Switzerland. Shell have launched a "pay-as-you-go" scheme in Germany similar to that offered by Hyundai in Switzerland. Progress appears slower in the United States, though Hyundai is starting operations in the United States and Israel in 2023.

Activity is also increasing with respect to hydrogen combustion, which allows for retrofitting of diesel engines, as done by Technocarb and CMB.TECH. The latter anticipate converting up to 20 trucks per month. Cummins also revealed a concept hydrogen combustion truck, suggesting that India may be the market most suited to this approach, which was later echoed in announcements by Tata Motors and JBC. New Zealand is also trialling hydrogen combustion, though in dual-fuel vehicles.

Buses

The stock of fuel cell buses grew similarly to that of light-duty vehicles, with around a 40% increase in 2022 compared with the previous year. As of June 2023, there are around 7 000[18] fuel cell buses worldwide, about 85% of which are located in China, which added around 1 300 fuel cell buses in 2022. Europe has the second largest stock, followed by Korea and then the United States.

Compared to trucks, there are fewer companies producing fuel cell buses, with under 20 in CALSTART's ZETI, though companies often produce a number of variations for different applications. Of those, just Foton (China) and Hyzon (United States) are producing coaches, and the others manufacturing transit buses, with no new models slated for 2023.

Germany, in particular, has seen a number of stakeholders opt for FCEVs, such as Deutsche Bahn, which approved the purchase of 60 fuel cell buses, as well as the cities of Weimar and Frankfurt. Other projects are underway in Liverpool in the United Kingdom, where the first of 20 planned fuel cell buses came into service in 2023, and in Brazil and Uruguay where the Chinese manufacturer Higer is trialling fuel cell buses. The largest announcements come from Korea, where 700 fuel cell

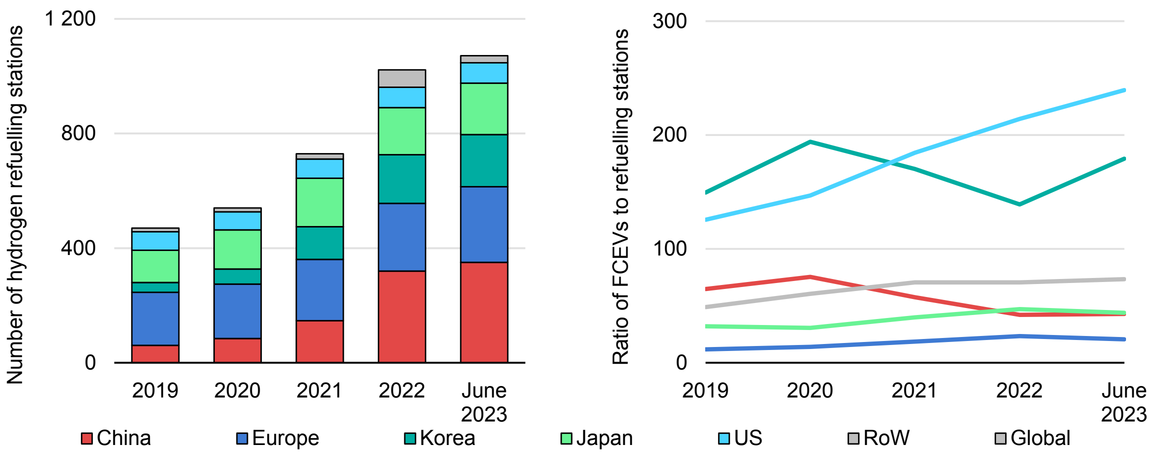
[18] For comparison, there were around 650 000 battery electric buses at the end of 2022.

buses will be deployed in Incheon by the end of 2024, and 1 300 in Seoul by 2030, partially funded through a subsidy scheme.

Hydrogen refuelling stations

Globally, there are around 1 100 hydrogen refuelling stations (HRS)[19] in operation as of June 2023, with hundreds more stations planned. Of the existing stations, well over 300 are in China, with Europe having around 250 HRS and both Korea and Japan having around 180 (Figure 2.8). In the United States, the stock of HRS has increased by only 10% since 2019. Given that the fleet of FCEVs has increased at a higher rate, the ratio of FCEVs to HRS has increased steadily over this time frame, reaching almost 240 vehicles per station in June 2023. Since 2019, the ratio of FCEVs per station in Korea has remained between 140 and 200. Other major markets (i.e. China, Japan and Europe) have fewer than 50 FCEVs per HRS.

Figure 2.8 Hydrogen refuelling stations by region and ratio of fuel cell electric vehicles to refuelling stations, 2019-June 2023



IEA. CC BY 4.0.

Note: FCEV = fuel cell electric vehicle; RoW = rest of world; US = United States. The number of hydrogen refuelling stations refers to both public (retail) and private stations. Includes data until June 2023 for the current year.

Sources: Advanced Fuel Cells Technology Collaboration Programme, H2stations.org by LBST, International Partnership for Hydrogen and Fuel Cells in the Economy and Clean Energy Ministerial Hydrogen Initiative country surveys.

In 2022, the number of hydrogen refuelling stations surpassed 1 000 for the first time.

With policy support from the EU Alternative Fuels Infrastructure Regulation, which mandates HRS every 200 km along major road networks and in all urban nodes from 2030 onwards, there are plans to expand the hydrogen refuelling network in

[19] This includes only HRS for road mobility applications and excludes refuelling points for non-road applications such as forklifts.

Europe, especially to serve the growing fuel cell truck fleet. TotalEnergies and Air Liquide are forming a joint venture to develop heavy-duty HRS focusing on Benelux, France and Germany, with the aim of deploying over 100 stations. H2 Mobility aims to more than double its network by 2030, adding 210 stations across Germany and Austria to the existing 90 today. Italy will fund the construction of 36 HRS. However, there have also been steps backwards in HRS deployment in Europe, with Shell closing their three HRS in the United Kingdom.

In the United States, hydrogen and electric truck-maker Nikola was awarded almost USD 42 million to establish 6 HRS in California, each capable of refuelling 80-100 trucks per day. In 2023, Nikola also launched a 700 bar mobile refueller with almost 1 t of storage.

Despite fewer announcements, the expansion of the HRS network was strongest in Asia in 2022, and this will likely be the case again in 2023. For example, SK Plug Hyverse, a joint venture between SK E&S and Plug Power, will establish around 40 HRS in Korea, while Shanghai, China intends to build 70 HRS by 2025.

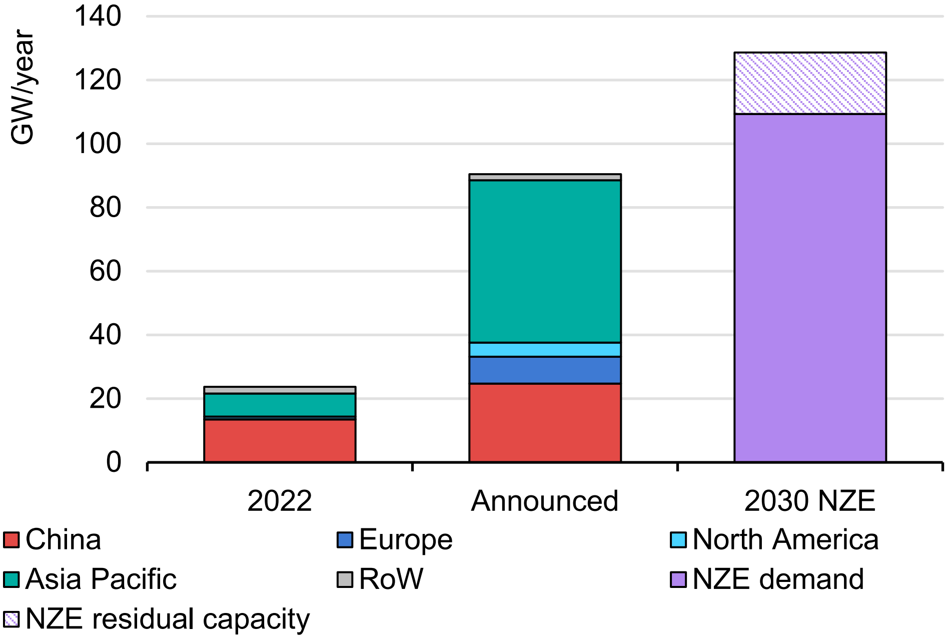
Locating hydrogen refuelling infrastructure at ports opens up the opportunity to provide hydrogen to a variety of potential users beyond trucks, such as forklifts and container stackers. The Port of Valencia, supported by the H2Ports project, provides such an example; elsewhere the Port of Hamburg has contracted Linde Engineering to build a compressed hydrogen refuelling station expected to begin operations in 2023. Air Products will build a commercial-scale liquid hydrogen refuelling station in the Port of Zeebrugge, Belgium. In the United States, ports are bidding to receive support to become “clean” hydrogen hubs.

Manufacturing capacity is scaling up

To capitalise on growing demand for mobile fuel cells, Hyundai opened its first hydrogen fuel cell production facility outside of Korea in 2023, in Guangzhou, China. Developments are also being seen in manufacturing of components in different regions. For example, Germany-based EKPO will invest in a new production site following a large order for bipolar plates. Other announcements come from Hexagon Purus, which opened a new hydrogen storage cylinder factory in the United States and broke ground on a new smaller factory in Canada. Ballard are aiming to reduce the cost of their next generation bipolar plate by up to 70% by investing in their Canadian facility, while also planning a membrane electrode assembly plant in Shanghai, supplying customers such as Siemens Mobility.

Capacity additions in 2022, together with a revised outlook for FCEV deployment in the NZE Scenario, mean that the gap to 2030 continues to close and mobile fuel cell manufacturers could meet 70% of what is needed in the NZE Scenario in 2030 (Figure 2.9).

Figure 2.9 Mobile fuel cell manufacturing capacity by country/region according to announced projects and in the Net Zero Emissions by 2050 Scenario, 2022-2030



Notes: NZE = Net Zero Emissions by 2050 Scenario; RoW = rest of world. Announced capacity includes existing capacity. The manufacturing capacity needed to meet projected demand in the NZE Scenario (NZE demand) is estimated assuming a utilisation rate of 85%. NZE residual capacity represents the manufacturing capacity that would remain unused, on average, which provides some flexibility to accommodate demand fluctuations. Capacities in 2022 and announced capacities include material handling equipment and other transport applications; NZE demand for fuel cells is based on fuel cell vehicles only.
Sources: IEA analysis based on data from E4tech and company announcements.

Expansion projects indicate a fourfold increase in fuel cell manufacturing for mobility applications, reaching 70% of what is needed in 2030 in the NZE Scenario.

Progress in non-road transport sectors

Rail

One of the largest orders for fuel cell trains comes from Italy, which is allocating EUR 24 million (~USD 25 million) for rolling stock, and EUR 276 million (~USD 290 million) for hydrogen production and supply, with specific lines identified and projects to have been completed by June 2026. In Germany, Alstom's hydrogen trains have progressed from trials to deployment, with 36 fuel cell trains in operation as of June 2023. They can now travel 1 175 km on a single refuel, with a line outside of Hamburg now set to be the first all-hydrogen service. Siemens Mobility also received an order for seven hydrogen trains in 2022, with deliveries expected by Q3/Q4 2024. Passenger hydrogen trains are also beginning trials in Canada, Spain and Japan. Arriva Netherlands launched a tender for four to six hydrogen trains, after successfully trialling them in 2020.

Hydrogen is also progressing in freight: Canadian Pacific used a hydrogen-powered locomotive on a commercial run in November 2022, and China also saw its first domestic use of hydrogen in rail starting with freight.

However, several stakeholders who previously committed to hydrogen have instead opted for electric trains, citing lower operating costs.

Shipping

The Global Maritime Forum has identified pilot and demonstration projects for zero-emission vessel technologies, of which over 50 each focus on ammonia combustion and hydrogen fuel cells, 30 on methanol and 25 on hydrogen combustion. In terms of numbers of Approvals in Principle[20], ammonia vessel designs have seen the most progress over 2022 and 2023.

In July 2023, the European Union adopted a new regulation, FuelEU maritime, to increase use of low-carbon fuels in shipping with special incentives for non-biological fuels such as from low-carbon hydrogen.

In March 2023, the first liquid hydrogen ferry, the MF Hydra, began operation in Norway, using zero-emission hydrogen, and PowerCell signed an agreement to provide their fuel cell system to two additional ferries in Norway set to be delivered in late 2024. In the same month, another hydrogen ferry, the Sea Change, became the first commercial maritime boat in the United States to be powered by hydrogen fuel cells. A hydrogen-powered barge was launched in the Netherlands, with a second retrofit underway. In addition, Damen Shipyards will produce two hydrogen-powered vessels for use in offshore wind farm construction, which are set to be delivered in 2025.

Aviation

Sustainable aviation fuels (SAFs), including low-emission hydrogen-based fuels such as synthetic kerosene, are at the highest levels of technology readiness compared with other potential solutions for aviation decarbonisation. Synthetic kerosene is a drop-in fuel that can directly replace fossil jet fuel without any technology switch. This can facilitate its uptake, since technology barriers are small and there are already some off-take agreements in place by aviation companies (see Creating demand for low-emission hydrogen). However, its high production cost is still a very significant barrier, which limits the scale of uptake and hinders project developers from taking FIDs (see the Chapter 3 Hydrogen production). In April 2023, the European Union provisionally agreed to implement ReFuelEU, an initiative aimed at decarbonising the aviation sector. The proposal

[20] As stated in the report by the Global Maritime Forum, ""Approval in Principle" refers to the evaluation and approval of a concept in its initial design stages, confirming its technical feasibility and moving it into further development stages."

includes a sub-mandate on the use of synthetic fuels, including synthetic kerosene.

Most announcements regarding the direct use of hydrogen come from newer entrants, such as Universal Hydrogen, which successfully completed a hydrogen powered flight in 2023, and ZeroAvia, which continues testing and advancing its hydrogen powertrain, and is also partnering with Absolut Hydrogen to develop liquid hydrogen refuelling infrastructure by 2027. Cranfield Aerospace Solutions and aircraft manufacturer Britten-Norman have announced the intention to merge their operations with the aim of creating the world's first fully integrated, zero-emission sub-regional aircraft for entry into service in 2026. Other companies advancing this technology in 2022 were Avio Aero, and H2Fly.

More established players such as Airbus are developing innovative cryogenic hydrogen tanks and, in a joint venture with Safran, are developing hydrogen refuelling facilities at Toulouse for their ZEROe aircraft. Meanwhile, Rolls-Royce has continued testing hydrogen jet engines.

With respect to commercial agreements, the establishment of a memorandum of understanding (MoU) for a “hydrogen flight corridor” between Hamburg and Rotterdam paves the way for hydrogen flights as early as 2026. Unmanned cargo aircraft company Dymond Aerospace signed an MoU for 200 hydrogen-powered motors from Duxion Motors; and ZeroAvia have received orders for 250 powertrains for US regional airline Air Cahana in California.

Other applications

The use of fuel cell material handling equipment (e.g. forklifts) has continued to expand. For example, at the end of 2022 there were over 60 000 fuel cell forklifts in operation in the United States, compared to around 50 000 the previous year.

Hydrogen applications in mining trucks are gaining momentum, with 120 kW proton exchange membrane (PEM) fuel cells and hydrogen-electric conversion of 2 wheeled excavators by zepp.solutions being deployed in India. Ballard are also supplying fuel cells for retrofitting mining trucks, receiving orders in March and June of 2023. JCB has had its hydrogen-powered digger approved by the UK government and it will be seen on construction sites in 2023.

Hydrogen continues to be an attractive option for various port operations, with recent examples including testing of a hydrogen fuel cell container stacker at the Port of Los Angeles in late 2022 and launch of the world’s first hydrogen dual-fuel straddle carrier at the Port of Antwerp in March 2023. The Port of Aberdeen will investigate liquid hydrogen-fuelled autonomous cargo ships in 2024.

More niche applications are also being investigated, as Kawasaki, Suzuki, Honda and Yamaha have formed the Hydrogen Small mobility and Engine technology

(HySE) group to develop engines for motorcycles, construction equipment, drones and other applications.

Buildings

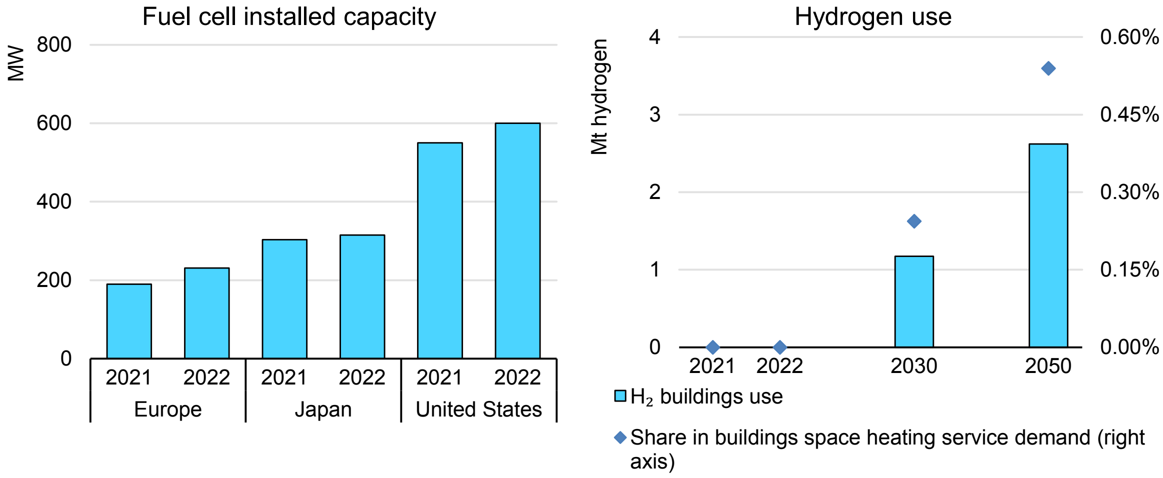
The contribution of hydrogen to meeting energy demand in the buildings sector remains negligible, with no significant development in 2022. As part of efforts to meet climate goals, there is a need to shift the use of fossil fuels in buildings towards low-carbon alternatives, but options such as electrification via heat pumps, district heating, and distributed renewables appear to be well ahead of hydrogen technologies. The use of hydrogen for decarbonisation in the buildings sector is therefore negligible in the NZE Scenario (hydrogen use reaches slightly over 1 Mt by 2030, 0.14% of total energy demand in the sector). Under current policies (in the IEA Stated Policies Scenario, [STEPS])[21], global hydrogen use in buildings reaches just 0.03 Mt by 2030.

Hydrogen use in buildings can contribute to some niche applications, such as heating old and poorly insulated buildings already connected to a natural gas grid in cold environments. However, due to the energy losses associated with hydrogen conversion, transport and use, hydrogen technologies for use in buildings are much less efficient than other available options, and they require new or repurposed infrastructure and devices. For instance, electric heat pumps require five to six times less electricity than a boiler running on electrolytic hydrogen to provide the same amount of heating.

There has been little progress in 2022 on the deployment of buildings technologies that might run on hydrogen. Currently, fuel cells in the building sector experienced modest market growth in the past few years, are installed for the most part in Europe, Japan, Korea and United States and predominantly run on fossil fuels (Figure 2.10). In Japan, thanks to the ENE-FARM project, the stock of deployed fuel cell micro-combined heat and power (CHP) units surpassed 450 000 at end-2022. Across various system sizes of stationary fuel cells, in 2022 the United States had installed capacity of around 600 MW, Japan about 315 MW, Europe around 230 MW and Korea about 20 MW.

[21] Projections for the STEPS Scenario in this *Global Hydrogen Review 2023* are based on modelling results derived from the most recent data and information available from governments, institutions, companies and other sources, as of July 2023. Updates will be included in the World Energy Outlook 2023 to be published in October 2023.

Figure 2.10 Fuel cell stock by region, 2021-2022, and hydrogen use in buildings in the Net Zero Emissions by 2050 Scenario, 2021-2050



Notes: H_2 = Hydrogen. The average fuel cell in Japan is assumed to be around 700 Watts.
Sources: IEA analysis based on International Partnership for Hydrogen and Fuel Cells in the Economy and Clean Energy Ministerial Hydrogen Initiative country surveys, Japan's Ministry of Economy, Trade and Industry, Fuel cells and Hydrogen Observatory and Fuel Cell & Hydrogen Energy Association.

Fuel cell deployment in buildings showed very limited progress in 2022, with most fuel cells still running on natural gas.

Advances in the use of pure hydrogen in buildings are limited to small pilots and demonstration projects. For example, in Lochem, the Netherlands, a pilot was started at the end of 2022 in which 12 historic homes were connected to a hydrogen supply and had hydrogen boilers installed to provide heating. In 2023, in Stad aan't Haringvliet, more than three-quarters of residents voted in favour of switching their heating systems from natural gas to "green" hydrogen[22]. However, some of these pilots face low social acceptance. In July 2023, the UK government abandoned plans for a trial to transition the natural gas network to hydrogen in Whitby, Cheshire, citing a lack of community backing as the primary reason.

The potential use of hydrogen in buildings is vaguely mentioned in multiple national hydrogen strategies or plans. Only Japan has set a concrete target, with 5.3 million micro-CHP fuel cells to be installed by 2030. However, micro-CHP fuel cells can use other fuels, and the target does not explicitly require the equipment to run on hydrogen.

[22] See Explanatory notes annex for the use of the term "green" hydrogen in this report.

Electricity generation

Hydrogen as fuel in the power sector is virtually non-existent today, with a share of less than 0.2% in the global electricity generation mix (and largely not from pure hydrogen, but mixed gases containing hydrogen from steel production, refineries or petrochemical plants).

Technologies to use pure hydrogen for electricity generation are commercially available today, with some designs of fuel cells, internal combustion engines (ICE) and gas turbines able to run on hydrogen-rich gases or even pure hydrogen. Using hydrogen in the form of ammonia could be another option for electricity generation. Co-firing of ammonia in coal-fired power plants has been successfully demonstrated in trials in Japan and China. Ammonia could also become a fuel for gas turbines. The direct use of 100% ammonia was successfully demonstrated in a 2 MW gas turbine in 2022 in Japan, with efforts underway to develop a 40 MW turbine for pure ammonia use.

While the use of hydrogen and ammonia can reduce CO_2 emissions in power generation, nitrogen oxides (NO_x) emissions are a concern. Modern gas turbines today use dry low NO_x technologies to manage NO_x emissions, allowing hydrogen co-firing shares of 30-60% (in volumetric terms)[23] depending on the burner design and combustion strategies implemented. R&D activities are underway to develop dry low NO_x gas turbines that can handle the full hydrogen blending range of up to 100%. For NO_x emissions from ammonia, flue gas treatment technologies such as selective catalytic reduction are available and already established for coal power plants. Ammonia combustion can also lead to nitrous oxide (N_2O) emissions, a strong GHG, but in the 2 MW demonstration project in Japan it was possible to reduce overall GHG emissions (CO_2 and N_2O combined) of the ammonia-fired gas turbine by 99% compared to a gas turbine using natural gas.

Projects using hydrogen and ammonia in electricity generation

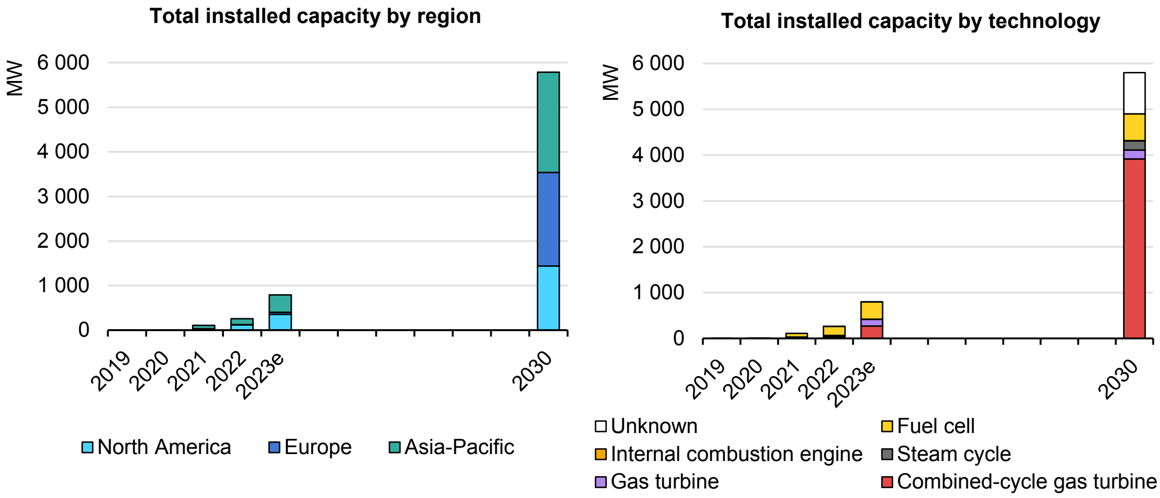
Interest in using hydrogen or ammonia as a fuel in the power sector has been growing over the past few years. Several utilities in North America, Europe and the Asia-Pacific region are exploring the possibility to co-fire hydrogen with natural gas in combined-cycle or open-cycle gas turbines. In Asia, several projects have been announced to explore the use of ammonia in coal-fired power plants. In the near-term, the use of hydrogen and ammonia can reduce the emissions from existing plants, while in the longer term power plants running entirely on hydrogen or ammonia can provide flexibility to the electricity system, in combination with

[23] Volumetric hydrogen co-firing share of 30% and 60% with natural gas corresponds in energy terms (lower heating values) to shares of 11% and 31%, respectively. If not stated otherwise, hydrogen shares are on a volumetric basis.

large-scale hydrogen storage. Projects to combine hydrogen production from renewable electricity with large-scale hydrogen storage for subsequent reconversion of part of the electricity are under development. For example, in the United States (Advanced Clean Energy Storage and IPP Renewed), gas turbines were delivered in 2022 for a new 840 MW combined-cycle power plant with a hydrogen co-firing share of 30% at start-up in 2025. In the United Kingdom (Saltend), a project aims to refurbish an existing 1 200 MW natural gas-fired combined heat and power plant for 30% hydrogen co-firing by 2027.

The announced projects using hydrogen and ammonia in the power sector could result in an installed capacity of 5 800 MW by 2030, an increase of 65% compared to the corresponding capacity identified in the GHR 2022 (Figure 2.11).[24] Around 70% of the projects are linked to hydrogen use in open-cycle or combined-cycle gas turbines, while the use of hydrogen in fuel cells accounts for 10% and the co-firing of ammonia in coal-fired power plants for 3% of the capacity of announced projects. Regionally, these projects are principally located in the Asia-Pacific region (39%), Europe (36%) and North America (25%).

Figure 2.11 Capacity in power generation using hydrogen and ammonia by region, historical and from announced projects, 2019-2030



Note: Values for 2023 are estimates, assuming plants with an announced start date in 2023 actually start operation in 2023.

Hydrogen and ammonia-fired power generation capacity could approach 5 800 MW by 2030 based on project announcements, principally from hydrogen co-fired in combined-cycle gas turbines.

[24] In the case of co-firing hydrogen or ammonia, the capacity corresponds to the total installed capacity multiplied by the co-firing share in energy terms.

In addition, several utilities announced plans to build new gas power plants or to upgrade existing gas power plants to be H_2-ready, i.e. able to co-fire a certain share of hydrogen. In most cases, concrete dates for starting co-firing have not been announced. The hydrogen share of this H_2-ready announced capacity would correspond to 3 400 MW, although this number most likely represents a lower range, based on projects for which information on the hydrogen co-firing capability has been released. Other new planned gas-fired power plants are also likely to be able to co-fire a certain amount of hydrogen, but no information has been made available. Similarly, existing gas-fired power plants are also able to handle certain shares of hydrogen, varying from 10% to 100%, depending on the gas turbine design.[25] Based on available information on the installed existing gas turbines and their maximum hydrogen blending shares from gas turbine manufacturers, the hydrogen-fired capacity from existing gas turbines could amount to more than 70 GW globally[26]. Again, this represents a lower bound, since detailed information was only available for 465 GW of the existing gas-fired capacity.

In addition to the growing number of announced projects, several demonstration projects have made progress since the GHR 2022, particularly in Asia:

- In July 2023, in Korea, Hanwha Impact achieved a 60% hydrogen co-firing share in an 80 MW gas turbine, the largest share to date in mid-to-large gas turbines.
- In Austria, first trials of co-firing hydrogen in an existing 395 MW gas-fired combined heat and power plant started in July 2023, with the goal to achieve a 15% hydrogen co-firing share in continuous operation.
- In the United States, a 38% hydrogen co-firing share was demonstrated in 2023 at an existing 753 MW combined-cycle power plant.
- For ICEs, earlier this year the manufacturer Wartsilä, together with WEC Energy, demonstrated a 25% hydrogen co-firing share in an unmodified ICE. New ICEs able to run on pure hydrogen are already offered by manufacturers.
- The Japanese utility JERA moved forward plans by one year to start the 20% co-firing of ammonia at its Hekinan coal power plant in the fiscal year 2023 (ending March 2024).
- In April 2023 the utility Kyushu (Japan) started ammonia co-firing trials at a 700 MW unit of its Reihoku coal power plant.
- In China, the Anhui Province Energy Group has completed trials of 10-35% co-firing of ammonia at a 300 MW unit of its Wanneng Tongling coal power plant over a 3-month period. The company plans further trials of 50% ammonia co-firing at a 1 GW coal unit.

[25] Other factors, such as the capability of the gas supply pipes and valves to handle certain hydrogen blending shares are not considered here, but are, of course, critical to assessing specific plants.
[26] Derived by taking the maximum co-firing share multiplied by the total capacity for individual plants.

- The State Power Investment Corporation (China) is working on a demonstration project to test pure hydrogen firing in a 1.7 MW gas turbine by the end of 2023.

Policy developments for hydrogen in the power sector

Since the release of the GHR 2022, several countries have announced or updated policies or targets for the use of hydrogen and ammonia in the power sector. In June 2023, Japan reconfirmed its commitment to the use of hydrogen and ammonia in the power sector in an amendment to its Basic Hydrogen Strategy from 2017. By 2030, Japan aims to demonstrate 30% co-firing of hydrogen in large gas turbines and 50% ammonia co-firing in coal power plants. In 2021, Japan set in its 6th Strategic Energy Plan the goal that hydrogen and ammonia should cover 1% of the electricity generation in 2030. Japan also announced in 2023 plans to hold capacity auctions for low-emission power technologies, with first auctions to start by October 2023, and to include existing coal power plants to be retrofitted for co-firing ammonia and the blending of hydrogen in new or existing gas-fired power plants.

In early 2023, Korea presented its 10th Basic Energy Plan for Electricity Supply and Demand, which provides revised targets[27] for 2030 of 13 TWh of electricity generation from co-firing of hydrogen and ammonia at existing gas and coal power plants, and 16 TWh stationary fuel cells using natural gas or hydrogen. For 2036, the plan foresees electricity generation of 47 TWh from hydrogen and ammonia. Korea also announced auctions for electricity generated from hydrogen.[28] A first tender for 650 GWh for electricity generated from hydrogen, without any constraints on the emission intensities, was launched in June 2023 for delivery in 2025, with five power plants winning the tender and 715 GWh in total being awarded. A second tender over 650 GWh will open in October 2023. Tenders for "clean" hydrogen are planned for 2024 for delivery in 2027, at a volume of 3 000-3 500 GWh. On the technology side, Korea aims to achieve 50% hydrogen co-firing in gas turbines and 20% ammonia co-firing in coal power plants by 2025.[29] In the longer term, the goal is to develop technologies allowing for 100% hydrogen firing in gas turbines and 50% ammonia co-firing in coal power plants.

Viet Nam set in its Power Development Master Plan VIII long-term goals for the use of hydrogen in the power sector, aiming to reach hydrogen-fired capacity of around 23-28 GW (4.5-5% of total capacity) by 2050, by converting gas-fired power plants from domestic natural gas or liquefied natural gas to hydrogen. Ammonia is also mentioned as an option to reach the phase-out of coal-fired power generation by 2050, but without any specific targets.

[27] Argus direct (2023), South Korea commits more funds to H2, slashes targets.
[28] Argus direct (2023), S Korea on track to open hydrogen power bidding market.
[29] Ibid.

In the United States, in 2023 the Environmental Protection Agency (EPA) proposed new standards for CO_2 emissions from combustion turbines. The standards will evolve over time and offer several options for compliance. The use of 30% hydrogen blends in turbines with intermediate- to high-capacity factors is proposed as a compliance option for 2032.

In Mexico, the energy ministry sets in its 2023-2037 national electricity system development program the goal to increase the share of hydrogen in the fuel input mix combined-cycle gas turbine (CCGT) plants to 30% by 2036, supported by converting 1 024 MW of CCGT capacity to being able to co-fire 30% of hydrogen by 2036.

In the amendment to its Combined Heat and Power (CHP) Act, Germany links incentives to the requirement that new CHP plants with an electrical capacity above 10 MW have to be H_2-ready, with conversion costs not exceeding 10% of the costs for building a similar new plant. A strategy for the power sector is being prepared by the German government, including the requirement that new gas power plants have to be H_2-ready. In addition, the government plans three tenders for hydrogen power plants and convertible or H_2-ready power plants. The first two tenders, each for a capacity of 4.4 GW, are for plants directly running on hydrogen, and will be supported through the German Renewable Energy Act, while the third tender of 15 GW is for new or existing power plants, which can initially run on natural gas, but must switch to hydrogen by 2035. One of the 4.4 GW tenders is for innovative concepts combining renewable electricity generation with hydrogen production and storage and reconversion into electricity.

Creating demand for low-emission hydrogen

In the quest to scale up the production of low-emission hydrogen, uncertainty surrounding its future demand has been identified by market players as a major obstacle. This is compounded by the higher production cost for low-emission hydrogen compared with hydrogen from unabated fossil fuels, the lack of infrastructure to deliver hydrogen to end-users, and the lack of clarity around regulation and certification. All these barriers are interconnected and cannot be addressed in isolation or sequentially, but rather must be tackled in a co-ordinated manner. For example, a programme to support project developers to reduce the cost gap between the production of low-emission hydrogen and the cost of incumbent unabated fossil fuel-based hydrogen may not be successful in bringing projects to market if the regulatory framework is unclear and developers struggle to demonstrate regulatory compliance, or if there is no demand from end-users and the developers struggle to find off-takers.

Significant efforts have been undertaken to develop programmes to support low-emission hydrogen production (such as the Important Projects of Common

European Interest [IPCEI] in the European Union, the Low Carbon Hydrogen Business Model in the United Kingdom or the Clean Hydrogen Production Tax Credit in the United States) and regulations.

Infrastructure development has only come into the policy debate very recently, with most efforts taking place in Europe, where European transmission system operators have started to plan the development of hydrogen infrastructure through the European Hydrogen Backbone initiative. Activity intensified after Russia's invasion of Ukraine, when European countries started developing new gas infrastructure to diversify supply away from Russian gas. This drew attention to the need to carefully consider how any new gas-related infrastructure could potentially support the future development of hydrogen in the context of climate ambitions.

On the demand side, measures to stimulate hydrogen demand have also only recently started to attract policy attention. Without robust demand, there is no market, and the viability of the entire low-emission hydrogen industry is jeopardised. For project developers, securing off-takers for their product is imperative, as it directly impacts their ability to attract investors and maintain favourable return rates. Realising the massive pipeline of announced projects dedicated to low-emission hydrogen production will depend on meeting the challenge of stimulating demand to scale up production and decrease costs.

In this section we explore the current outlook for low-emission hydrogen demand, starting with options for creating demand in both existing and new applications. Then we assess the demand that can be created through the plans and efforts being made by governments and the private sector. Finally, we present some options to stimulate low-emission hydrogen demand and close the gap between existing efforts and what is needed to get on track with the NZE Scenario.

A two-pronged approach to creating demand for low-emission hydrogen

Switching to low-emission hydrogen in existing applications

The first priority is to switch the existing demand for hydrogen in industry and refining from using unabated fossil-based hydrogen to low-emission hydrogen. Replacing existing dedicated hydrogen production using unabated fossil fuels (80 Mt)[30] with production using water electrolysis would require deploying about 730-940 GW of electrolysis capacity, while retrofitting all existing production

[30] Dedicated hydrogen production accounted for 80 Mt in 2022, with the remaining 15 Mt being produced as a by-product.

assets with CCUS would require a CO_2 capture capacity of 710- 880 Mt per year[31]. This underscores the tremendous opportunity to scale up low-emission hydrogen production by replacing existing hydrogen demand.

This substitution involves a like-for-like replacement, so has limited technical challenges. However, it is hindered by the higher cost of low-emission hydrogen, especially given that most of the supply from unabated fossil fuels is from existing plants operating on a marginal cost basis. Closing the cost gap to facilitate the creation of demand for low-emission hydrogen in these applications – including equipping existing hydrogen units with high levels of CCUS – requires one of two options, or a combination of both:

- One option would be to apply a sustained, elevated carbon price that raises costs for all hydrogen users, but by a lower amount for users of low-emission hydrogen. If all users face higher costs, it would be easier to pass them on to consumers and, in many cases, hydrogen costs are not a large component of total production costs. However, only about 23% of global GHG emissions are covered by a carbon price today. Moreover, the average level of carbon pricing applied is still low, with less than 5% of GHG emissions covered by a carbon price above USD 50/t CO_2. Furthermore, carbon price volatility in some regions makes it difficult to persuade hydrogen users to switch to a new supply. Even if they are included in a carbon pricing system, in many cases hydrogen consumers are partially or totally exempt from the real carbon price: for instance, in the UK and EU Emissions Trading Systems (ETS), industrial facilities currently receive free allowances (although in the EU ETS these will be gradually phased out for fertiliser producers from 2026). To reach cost parity with a facility that produces hydrogen from unabated natural gas, a carbon price of USD 50-60/t CO_2 would be currently needed for the same facility equipped with CCUS, and USD 230-550/t CO_2 for hydrogen produced with renewable electricity.[32] The EU ETS price has fluctuated in the range of EUR 20-100/t CO_2 (USD 23-105/t CO_2) over the past five years, and – while it peaked at over EUR 100/t CO_2 (USD 105/t CO_2) in 2023 – it has not yet offered enough stability or predictability to be bankable for long-duration hydrogen projects and contracts. In Canada, the minimum federal price started at CAD 20 (Canadian dollars)/t CO_2 (~USD 15/t CO_2) in 2019 and increased to CAD 50/t CO_2 (~USD 38/t CO_2) in 2022. Other complementary carbon policy instruments, such as voluntary carbon credit markets may also act as a catalyst to bring down the costs of low-emission hydrogen (see Box 2.2).
- Another option is to offer payments to producers of low-emission hydrogen so that they can compete on price with other hydrogen supplies, or payments to consumers to encourage them to use low-emission hydrogen by partially or totally

[31] Assuming 65-70% efficiency and 50-60% load factor electrolysers; and 90-98% capture rate and 85-95% load factor for carbon capture facilities.

[32] Assuming marginal production cost for existing facilities, the CAPEX of CCUS equipment and OPEX for retrofitted facilities and the full CAPEX and OPEX costs for renewable-based facilities. Assuming a natural gas price of USD 5/MBtu and USD 25-40/MWh and 25-55% load factor for renewable electricity.

compensating for the additional cost. The H2Global mechanism uses a combination of these two approaches, by covering the cost gap between a selling price and a buying price, which are established through a double-auction model. Under these options, some costs are borne by taxpayers rather than consumers, but for users this can offer a faster path to scale up and reach cost parity. Such support schemes are still in their infancy in most regions, and the availability of some of the most promising schemes has been delayed. Delays can have a major impact on projects in today's dynamic cost environment, in which inflation has already eaten into the attractiveness of subsidies that were announced a year or two ago. Electrolyser projects, in particular, are having to renegotiate quoted prices from suppliers to try to achieve financial viability (see Chapter 5 Investment, finance and innovation).

Box 2.2 The role of voluntary carbon credit markets in scaling up low-emission hydrogen

In addition to support from public policies, it is essential to mobilise funding in order to facilitate the financing of low-emission hydrogen projects. One option is the utilisation of carbon credit markets. Carbon credits can complement other funding sources for low-emission hydrogen initiatives, in a similar way to what is happening with direct air capture and storage projects. However, as of August 2023, there are no carbon credits issued by low-emissions hydrogen because of the lack of a globally adopted standard methodology for assessing GHG emissions from hydrogen production, transport and use that can be used as a reference to develop a standard crediting methodology. Nevertheless, the Hydrogen for Net Zero (H2NZ) Initiative is trying to fill this gap and actively formulating novel methodologies for crediting within voluntary carbon markets, with the aim of unlocking financial support for low-emission hydrogen ventures. Furthermore, there is potential to leverage carbon credits to help bridge the price premium gap for hydrogen-based fuels as SAFs. SAF prices are currently significantly higher than those of conventional jet fuel, and consequently demand is low, and SAF producers today have to rely primarily on off-take agreements.

In order to close the cost gap, governments can also facilitate the creation of demand for low-emission hydrogen by adopting regulatory measures such as quotas or mandates that enforce the use of low-emission hydrogen in existing applications. Similarly to the adoption of high carbon prices, this would result in higher supply costs that will be passed on to consumers, but the impact on the final products is expected to be rather limited: for example, the cost of a car would increase only marginally when produced with steel produced using low-emission hydrogen.

Creating demand in new applications

The second approach to demand creation involves expanding the demand for low-emission hydrogen (and hydrogen-based fuels) in new applications, where other low-emission alternatives are limited and where hydrogen can therefore play a pivotal role in decarbonisation. However, this expansion presents a greater challenge as it necessitates the adoption of technologies that are, in most cases, still under development, as well as infrastructure adaptation and expansion, and the establishment of fit-for-purpose standards and regulations. The adoption of standards and regulations is particularly important to avoid the risk of unabated fossil-based hydrogen filling demand in new applications, which in most cases would result in higher life-cycle CO_2 emissions than the use of incumbent fossil fuels. To prevent this risk, robust and smart regulations are imperative to ensure only low-emission hydrogen is used in these applications.[33]

Policies to stimulate demand creation

Governments have so far set targets for the deployment of hydrogen technologies in existing applications – particularly in industry – and in new applications, predominantly in transport. For example, Japan aims to have 800 000 FCEVs on the road by 2030, while the European Union targets meeting 42% of industrial hydrogen demand with renewable fuels of non-biological origin (RFNBOs)[34] by the same year. While these targets can signal intent to producers and consumers, in the absence of other measures, they are insufficient to encourage market players to fully commit to scaling up the use of low-emission hydrogen, given the associated higher costs. Robust policies and regulations – and not just targets – are required to create the right investment environment, combining both support to incentivise project developers and penalties for non-compliance.

There are numerous potential support measures to stimulate low-emission hydrogen demand in both traditional and new applications, ranging from measures that prioritise hydrogen and hydrogen-based fuels (such as mandates for low-emission hydrogen in existing applications) to more technology-neutral sectoral measures that prioritise decarbonisation (see Table 2.1). The latter includes instruments such as Carbon Contracts for Difference (CCfD), by which the government covers the difference between the CO_2 abatement costs of a project and a CO_2 reference price, but the selection of the technology to reduce the emissions is made by the project developer. Other technology-neutral measures include mandates for zero-emission vehicles (ZEVs), in which a minimum share

[33] This aspect is beyond the scope of the analysis presented in this chapter since it has been addressed in detail in our recent report Towards hydrogen definitions based on their emissions intensity.
[34] The RFNBOs include hydrogen and hydrogen-based fuels produced from renewable energy sources other than biomass.

of sales has to be met with ZEVs, but the automaker decides whether that is met with battery electric vehicles (BEVs), FCEVs, or a combination of both.

To a large extent, such policies have so far been announced, but not yet implemented. As a result, current projections in the STEPS suggest that low-emission hydrogen demand may reach around 7 Mt by 2030, a significant increase from current use of less than 1 Mt per year. However, this falls short of meeting global hydrogen demand targets set by governments, which are estimated to reach nearly 14 Mt by 2030, with substantial contributions from traditional applications in industry and refining sectors, but also from the transport sector (Figure 2.12).

Even if policy action was implemented to meet targets for hydrogen demand, the ambition of these targets is significantly lower than the objectives set by governments for low-emission hydrogen production. Globally, government targets for low-emission hydrogen production account for 27-35 Mt by 2030 (see Chapter 6 Policies), far exceeding the demand envisaged by demand targets.

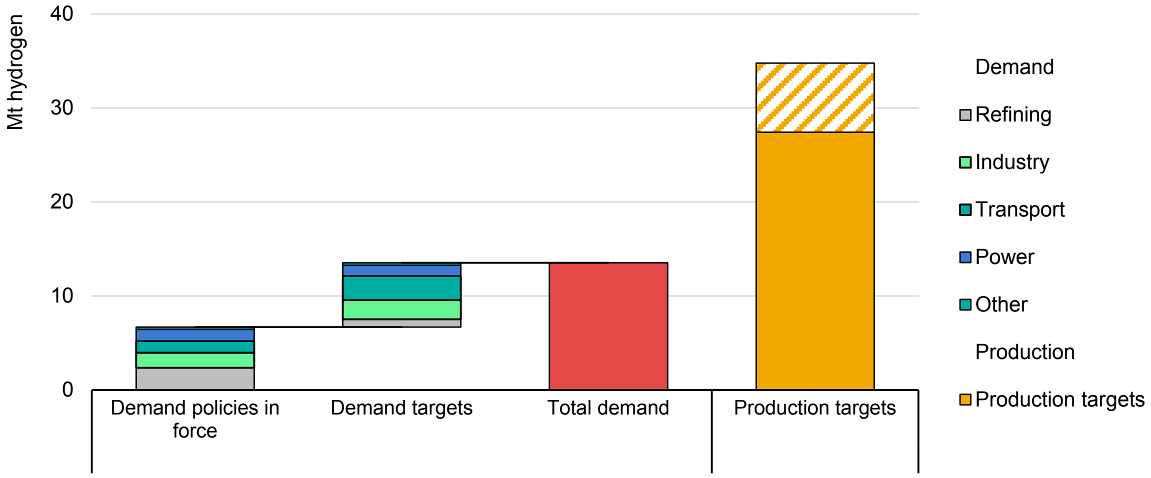
The current pipeline of announced projects for the production of low-emission hydrogen accounts for up to 38 Mt by 2030 (see Chapter 3 Hydrogen production), which is relatively well-aligned with the global production targets announced by governments. However, the imbalance between demand and supply ambitions for low-emission hydrogen poses a risk for the announced hydrogen production projects to reach FID (only 4% have already done so) and, therefore, to achieve government targets for low-emission hydrogen production. This discrepancy could also impede the development of low-emission hydrogen supply chains.

At the individual country level, an imbalance in favour of hydrogen production targets may be acceptable to countries that could become hydrogen exporters, such as Australia, Chile or Middle East countries. For example, in the STEPS, low-emission hydrogen demand in Chile reaches slightly more than 100 kt by 2030, whereas the production target is for 25 GW of electrolysis (able to produce 2.1-2.8 Mt H_2[35]) by 2030. Achieving production targets would require the creation of demand for low-emission hydrogen at a level above the production targets in regions that could become hydrogen importers, such as Europe, Japan and Korea. However, the combined demand for low-emission hydrogen in these three regions accounts for 1.7 Mt in the STEPS, whereas their production targets account for 6.6-12.3 Mt by 2030[36], i.e. even above their own targets for low-emission hydrogen demand.

[35] Assuming 65-70% efficiency and 50-60% load factor.
[36] The difference between the lower and the upper range mostly results from consideration of the EU Fit for 55 package for the lower range and the RePowerEU plan for the upper range.

To rectify this situation, governments must clarify their ambitions with regards to demand. This should include synchronising targets for low-emission production and consumption, as well as expediting the implementation of concrete supportive policies that can reduce risk in order to foster adoption among first movers.

Figure 2.12 Potential demand for low-emission hydrogen created by implemented policies and government targets, and production targeted by governments, 2030



Notes: In Production targets, the dashed area represents policy targets' ranges. For countries that do not have a production target, the low-emission hydrogen production is estimated from the capacity targets assuming a capacity factor of 57% and an energy efficiency of 69% for electrolysers and 90% for fossil-based technologies.

Meeting government targets could generate up to 14 Mt of low-emission hydrogen demand, far less than the 27-35 Mt envisaged by low-emission hydrogen production targets.

Table 2.1 Examples of policies to stimulate demand for low-emission hydrogen

Policy	Description	Examples
Measures focused on promoting hydrogen and hydrogen-based fuels		
Quotas and mandates	Governments can establish a minimum share of low-emission hydrogen or hydrogen-based fuel consumption in a specific sector.	**Industry** **Implemented**: Romania passed a law that mandates industrial hydrogen users to meet 50% of their demand with low-emission hydrogen by 2030. **Announced**: the Netherlands announced that it will set renewable hydrogen mandates for industry from 2026; India announced plans to introduce a mandatory low-emission hydrogen purchase obligation for the fertiliser and refining sector.
		Transport **Implemented**: Romania passed a law mandating transport fuel suppliers to meet 5% of their fuel sales with renewable hydrogen-based fuels by 2030. **Announced**: In April 2023, the European Council and Parliament reached a political agreement on the ReFuelEU aviation initiative, which includes a minimum share of 1.2% of synthetic fuels in aviation to be implemented from 2030, and the FuelEU Maritime initiative, which includes a subtarget of 2% of RFNBO in maritime fuel from 2034, if these fuels have not reached 1% by 2031.
End-use subsidies	Governments can offer financial benefits to end-users that purchase low-emission hydrogen and hydrogen-based fuels.	**Cross-sectoral** **Implemented**: In the United States, Colorado and Illinois passed bills creating a USD 1/kg H_2 tax credit for the use of "clean" hydrogen in sectors where emissions are hard to abate. **Announced**: in August 2023, New Zealand launched a consultation on a consumption rebate scheme to be implemented from 2025. The Netherlands and the United States (USD 1 billion budget) have each announced they are exploring end-use subsidies for the use of low-emission hydrogen.
CAPEX and OPEX subsidies	Governments can offer subsidies to cover the capital expenditures of industrial projects towards the purchase of fuel cell vehicles or hydrogen-powered equipment and to cover operating expenses (similar to tax credits for fuel electricity or fuel subsidies for hydrogen use in transport).	**Industry and refining** **Implemented**: the European Commission provides grants through the Innovation Fund and approved EUR 5.2 billion (USD 5.5 billion) for the Hy2Use (IPCEI) to fund projects aiming to use renewable hydrogen in industrial applications. Governments including Canada, Italy, Poland and Spain have also provided subsidies for projects aiming to use low-emission hydrogen in industry and refining.
		Transport **Implemented**: several countries, such as Korea, Japan and the United States have subsidies for FCEVs. **Announced**: New Zealand allocated NZD 30 million (New Zealand dollars) (USD 19 million) in its Budget 2023 to create a Clean Heavy Vehicle Grant for heavy-duty ZEVs, including fuel cell heavy vehicles
Technology-neutral sectoral measures		
Carbon Contracts for Difference (CCfD)	Government can pay project developers the difference between their cost per tonne of CO_2 avoided (fixed in an auction) and a CO_2 reference price.	**Industry** **Announced**: the German government announced a CCfD programme to accelerate the phasing-out of fossil fuels in energy-intensive industries, replacing them with low-emission technologies (including hydrogen), with the first auction expected at the end of 2023.

Policy	Description	Examples
Public procurement	Governments can use their purchasing power to encourage contractors to prioritise the procurement of near-zero emission materials and ZEVs.	**Industry** **Implemented**: in December 2021 the US government launched the Federal Buy Clean Initiative to prioritise procurement of low-carbon construction materials, in particular steel and concrete. **Announced**: in March 2023 the United Kingdom launched a consultation on measures to prevent carbon leakage risk, including public procurement of industrial products such as steel and cement. **Transport** **Implemented**: in November 2020, Norway set rules for the tender of the largest ferry connection in the country to use hydrogen; in July 2021, Ireland transcribed into law the EU Clean Vehicles Directive, which defines procurement targets for clean light- and heavy-duty vehicles for government fleets. **Announced**: in July 2023 UK National Highways announced the purchase of "low-carbon" hydrogen to be used in construction machinery.
Fuel economy/ CO_2 emissions standards	Governments can establish standards on vehicle fuel economy or CO_2 emissions, which can incentivise the adoption of ZEVs, including hydrogen vehicles.	**Transport** **Implemented**: in April 2023, the EU Parliament and Council adopted an amended regulation to strengthen CO_2 emission standards for new passenger cars and light commercial vehicles; China is currently in Phase V of its fuel consumption standards, which requires carmakers meet fleet-wide average targets of 4.0 l/100 km by 2025 and 3.2 l/100 km by 2030. **Announced**: in April 2023, the US EPA proposed GHG standards for heavy-duty vehicles (HDVs).
ZEV mandates	Governments can mandate a minimum share of ZEVs, which can encourage FCEV adoption. Credits related to meeting ZEV mandates are often combined with fuel economy/CO_2 standards.	**Transport** **Implemented**: California (United States) has a ZEV mandate since 1990. The current policy requires that ZEVs (and plug-in hybrid electric vehicles) represent 100% of new car sales by 2035. **Announced**: as an outcome of consultation, the United Kingdom has proposed a zero-emission car and van mandate that would require 100% ZEV sales from 2035.
Carbon taxes	Governments can apply a tax to CO_2 or other GHG emissions in specific sectors or across the whole energy system to penalise emitters	**Industry** **Implemented**: Since 2017, Chile has been applying a carbon tax on the power and industry sectors, notably on installations with an installed thermal power exceeding a specified threshold capacity. The carbon tax in Portugal also covers industry sector emissions. **Transport** **Implemented**: Denmark, Ireland and Portugal have a carbon tax in place covering emissions that are outside the scope of the EU ETS, in particular emissions from the transport sector.
Emissions Trading Systems (ETS)	Governments may set a limit on CO_2 emissions in specific sectors, or across the whole economy. Governments allocate emissions allowances among entities operating in those sectors. If companies reduce their emissions under their allocated allowance, they can trade the difference with companies that emit over their allocated thresholds and need to purchase allowances to comply with their ETS obligations.	**Cross-sectoral** **Implemented**: over 30 ETS are already in operation at national (e.g. China, the European Union and the United Kingdom) and sub-national (e.g. California and Québec) level. Some, such as the European Union, the United Kingdom and Québec, also cover hydrogen production.

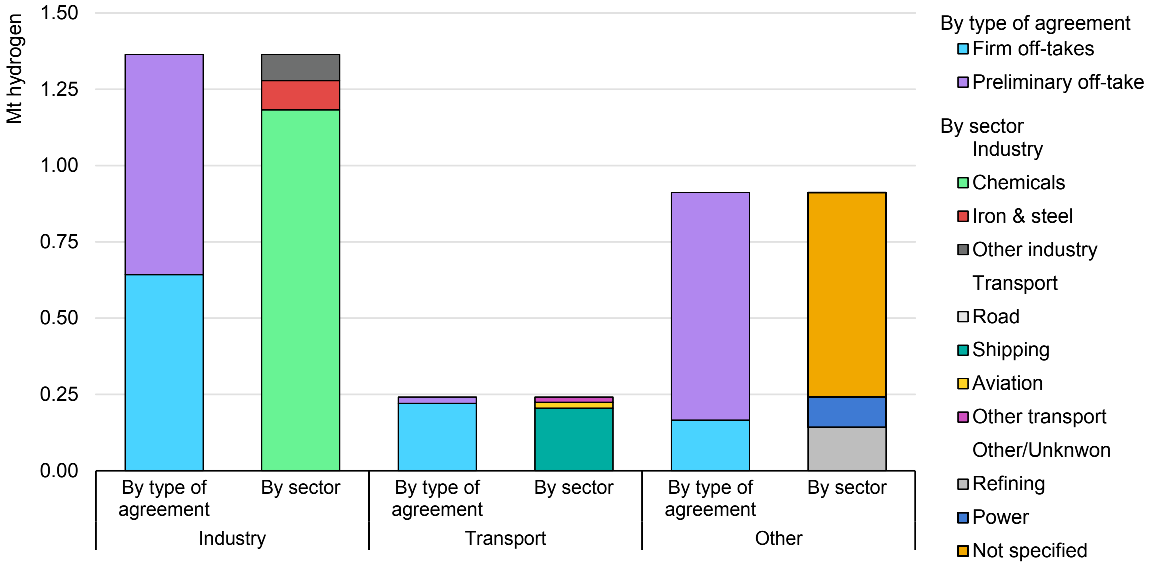
Note: See Explanatory notes annex for the use of the term "low-carbon" and "clean" hydrogen in this report.

First steps from industrial stakeholders

The private sector has made first moves in adopting low-emission hydrogen, driven by various factors including compliance with decarbonisation policies, government signals favouring hydrogen adoption, public reputation considerations, and strategic decisions to lead in technology development and new markets. As a result, many companies have initiated off-take agreements for low-emission hydrogen and hydrogen-based fuels.

Most of these agreements are still preliminary, often in the form of MoUs or Heads of Agreement, but they can lay the groundwork for potential transactions. An estimate of more than 2 Mt of low-emission hydrogen demand can be unlocked by 2030 from the off-take agreements that have been publicly announced by companies, but only around half of that demand comes from firm deals (Figure 2.13).

Figure 2.13 Potential demand for low-emission hydrogen that can be achieved with announced private off-take agreements by 2030



Notes: "Unknown" includes off-take agreements for which the end use of hydrogen and hydrogen-based fuels has not been disclosed. Only off-take agreements disclosing the amount of low-emission hydrogen and hydrogen-based fuels agreed and stating that they will take place before 2030 have been included.
Source: IEA analysis based on announcements of off-take agreements for hydrogen and hydrogen-based fuels.

The private sector has signed off-take agreements accounting for more than 2 Mt of low-emission hydrogen demand.

The industrial sector has been at the forefront of this movement, with off-take agreements for almost 1.3 Mt of demand for low-emission hydrogen. Around half of this demand comes from firm agreements, reflecting a strong commitment to transitioning to cleaner energy sources. Within the industrial sector, the chemical subsector accounts for a significant 85% of the volumes agreed, showing that traditional applications for hydrogen are more prepared to take up low-emission hydrogen in the short term.

Several notable agreements have been forged for low-emission ammonia supply. For instance, Linde has committed to supply low-emission hydrogen to OCI for the production of 1.1 Mt of ammonia in a new plant in the United States. Additionally, Iberdrola and Teal have secured agreements to provide 0.9 Mt of low-emission ammonia to Trammo.

In the steel sector, H2 Green Steel has been proactive in signing customer contracts for over 1.5 Mt of DRI per year (constituting around 60% of their planned initial production capacity), which would require around 100 kt of hydrogen produced from electrolysis and renewable electricity.

Although the transport sector has shown slower progress compared to the industrial sector, some significant agreements have been made. The shipping sector, in particular, has seen substantial activity, with prominent logistics companies signing agreements for synthetic methanol and synthetic marine diesel to decarbonise their operations. In the aviation sector, although the focus has been on lower-cost biojet fuels, hydrogen-based fuels are expected to gain ground in the future due to their greater resource potential and life-cycle emissions reductions. Presently, the majority of deals in the aviation sector originate from US companies.

The refining and electricity generation sectors have also seen a limited number of off-take agreements, but they represent considerable volumes. For example, Yara and CF Industries secured a tender to supply 90 kt of hydrogen in the form of ammonia to JERA for co-firing in coal power plants. VERTEX and Essar Oil UK have agreed to supply hydrogen produced with natural gas and CCUS to the Stanlow refinery in the United Kingdom. There have been also some off-take agreements linked to development of international hydrogen trade for which the end use of hydrogen and hydrogen-based fuels has not been disclosed or is expected to cover numerous applications in the destination region, such as the one between DAI Infrastructure and Freepan Holdings (for 800 kt NH_3/yr) or the one between RWE and Hyphen (300 kt NH_3/yr).

Although the current demand for low-emission hydrogen that can be generated from these deals stands more than to 2 Mt, this should be considered a conservative estimate of the private sector's preparedness to adopt low-emission hydrogen and hydrogen-based fuels. Many agreements have not been made public, or – if they have – the details of the deal are undisclosed due to the competitive nature of the market and companies' desire to protect their strategies. Moreover, within refining and the industrial sector, some companies are already developing projects to produce their own low-emission hydrogen to meet part of their total hydrogen demand, without the need to sign an off-take agreement with an external supplier. This mirrors the way in which those companies produce and use their own hydrogen from unabated fossil fuels today. Some advanced examples include projects developed by Shell and Sinopec for the use of low-emission hydrogen in refining, or by Yara for the use of low-emission hydrogen in fertiliser production. Looking ahead, the pipeline of announced projects indicates potential self-produced low-emission hydrogen volumes of more than 2 Mt in the industrial sector and over 1 Mt in refining. However, firm commitments for self-production of low-emission hydrogen presently represent less than 1 Mt in industry and around 0.3 Mt in refining.

International co-operation to aggregate demand

Both governments and the private sector acknowledge the formidable challenge of scaling up the production and use of low-emission hydrogen at the required pace through individual action alone. Recognising the importance of collaboration on a global scale, international co-operation has emerged as a key pillar in the pursuit of this objective.

In recent years, governments and companies have launched a series of initiatives to foster collaboration in the deployment of low-emission technologies, including those related to hydrogen (Table 2.2). These ambitious endeavours aim to bring together diverse stakeholders, comprising numerous governments and private sector players, united in their pursuit of common goals for the widespread adoption of low-emission technologies and fuels, along with ambitious emission reduction targets.

While various initiatives have been set in motion, it is noteworthy that, with the exception of the Green Hydrogen Catapult, most lack a specific focus on hydrogen. Instead, their primary emphasis lies on the broader adoption of low-emission technologies and the reduction of emissions across various sectors. The transport sector garners significant attention, with a secondary focus on the industrial sector. Certain initiatives, such as the First Movers Coalition and the Mission Possible Partnership, encompass commitments spanning multiple sub-sectors crucial for hydrogen, including industry (aluminium, cement, chemicals and steel) and transport (aviation, shipping, and trucking).

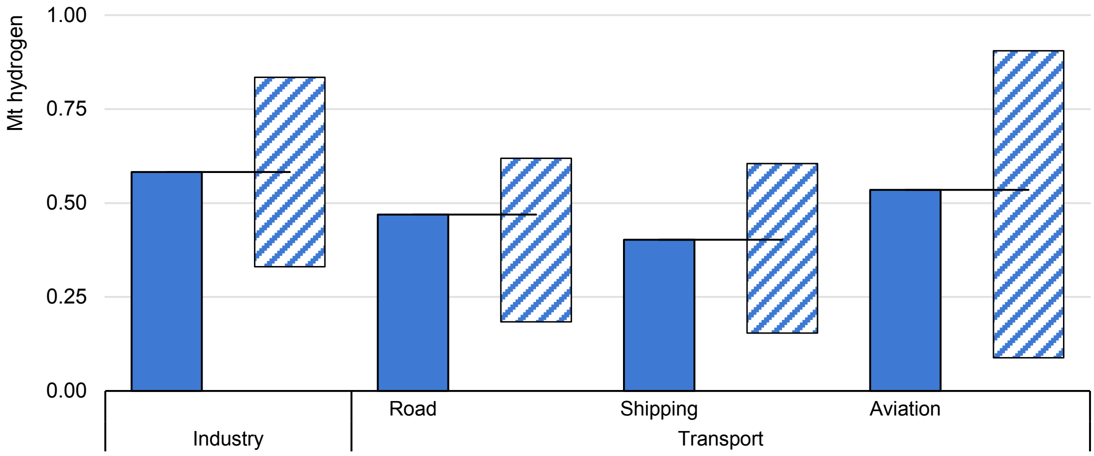
Table 2.2 Selected international initiatives for the deployment of low-emission technologies

Initiative	Description and pledges
First Movers Coalition	Coalition of companies using their purchasing power to create early markets for innovative clean technologies across sectors in which emissions are hard to abate, including commitments on aluminium, aviation, carbon dioxide removal, cement and concrete, shipping, steel and trucking.
Mission Possible Partnership	Private-led coalition driving industrial decarbonisation across the entire value chain of the highest-emitting heavy industry and transport sectors, with strategies for aluminium, aviation, cement and concrete, chemicals, shipping, steel and trucking.
Green Hydrogen Catapult	Global private-led initiative whose goal is to drive a massive low-emission hydrogen scale-up (80 GW) to be used in trucking, aviation, shipping, fertilisers, steel and methanol.
Clean Energy Ministerial Industrial Deep Decarbonisation Initiative	Government initiative aiming to stimulate global demand for low-carbon industrial materials by encouraging governments and the private sector to buy low-carbon steel and cement, including through a Green Public Procurement Pledge.
SteelZero	Coalition of companies currently pledging to procure 50% low-emission or responsible steel by 2030 and 100% near-zero steel by 2050.
C40 cities	Global network of mayors of the world's leading cities with common emission reduction goal, including a target to reduce embodied emissions of new constructions by 50% by 2030.
Clean Energy Ministerial Global Commercial Drive to Zero Campaign	Coalition of leading countries committed to working together to enable 100% zero-emission new truck and bus sales by 2040 with an interim goal of 30% ZEV sales by 2030.
Accelerating to Zero	Coalition of governments from leading and emerging markets, regional governments, automotive manufacturers, fleet operators, and more, committed to all sales of cars and vans being zero-emission by 2040, and no later than 2035 in leading markets.
EV100+	A private industry pledge where signatories commit to transition their medium and heavy-duty vehicles to zero-emission by 2040 in leading markets.
Federal Buy Clean Initiative	The US government pledges to prioritise the procurement of low-carbon materials made in the United States, such as steel and cement, using their important purchasing power to help national industries.
Mission Innovation Zero Emissions Shipping Mission	Coalition of governments and maritime companies with pledges to deploy at least 200 ships using zero-emission fuels, use at least 5% of zero-emission fuels in shipping and deploy fuelling infrastructure in at least 10 large ports by 2030.
Clydebank Declaration	Coalition of governments aiming to establish at least six zero-emission maritime routes before 2030.

Based on the commitments made by these initiatives, we have estimated a potential to create demand for low-emission hydrogen in the range of 0.8 to 3 Mt by the year 2030 (Figure 2.14). All four sectors covered by these initiatives (industry, road transport, aviation and shipping) can achieve similar levels of hydrogen demand, with central estimates ranging between 0.4 and 0.6 Mt in each sector by 2030.

However, despite the positive intent of these initiatives, the implementation of their pledges and their real impact remains to be seen. In addition, to ensure that the initiatives can most effectively contribute to the adoption of low-emission hydrogen, there are some issues that need to be addressed. Many sectoral initiatives, particularly in the transport subsector, share a very similar membership, with commitments often overlapping, resulting in duplication of efforts instead of a meaningful cumulative impact.

Figure 2.14 Potential demand for low-emission hydrogen that can be achieved with the commitments of international initiatives, 2030



Notes: Aviation includes hydrogen demand to produce synthetic kerosene and for the hydrogenation of biofuels. Dashed areas denote the variability between the most conservative and boldest estimates. For industry, in the First Mover Coalition, the steel demand of members was estimated based on their industrial activity. For the Industrial Deep Decarbonation Initiative, it is assumed that all 9 currently member countries make a pledge to use 10% low-emission steel in their public procurement. For road transport, cumulative sales of fuel cell electric vehicles (FCEVs) in line with the Drive to Zero and Accelerating to Zero campaigns in countries that signed the declarations were assumed to result in 0.4-1.4% and 0.05-0.15% of 2030 fuel consumption in the heavy-duty and light-duty fleets, respectively, being hydrogen. For shipping, in line with the Zero Emissions Shipping Mission and Clydebank Declaration, 5% and 10% of energy was assumed to come from low-carbon fuels respectively, with campaigns assumed to cover 5-10% and 0.1–0.3% of global demand respectively; the lower and upper limits were found by assuming 50% of demand being served by synthetic methanol and up to 100% served by low-emission ammonia. For aviation, the First Movers Coalition and Clean Skies for Tomorrow Coalition provide sustainable aviation fuel targets of 5% and 10% respectively: these are translated into hydrogen demand with the lower limit using hydrogen only in biofuel upgrading, and the upper limit also including synthetic fuel production. Initiatives which did not have a target that could be translated into a hydrogen volume were not included.

Pledges from international initiatives could create up to 3 Mt of demand for low-emission hydrogen, but estimates are uncertain since pledges are mostly technology-neutral.

While these initiatives serve to signal potential hydrogen demand, their technology-agnostic nature introduces uncertainty on how much demand they can effectively create, as shown by the wide variability of the projections presented in our analysis. This is hindering potential hydrogen suppliers from accurately gauging the extent of the demand they can anticipate. In an effort to address this challenge and provide greater clarity, during the 27th Conference of the Parties (COP 27) (under the framework of the Breakthrough Agenda dialogues) the First Movers Coalition pledged to present a comprehensive estimate of hydrogen demand arising from their members' commitments at COP 28. An initial estimate made by the First Movers Coalition suggests that the commitments of its members can generate between 0.5 and 0.9 Mt of hydrogen demand by 2030. The Coalition is expected to release further details of this estimate, including the sectoral breakdown, later this year. If other initiatives were to follow suit and transparently communicate potential estimates for hydrogen demand resulting from their activities, it would significantly bolster the signal sent to low-emission hydrogen producers, thereby catalysing further progress.

An important observation is that these initiatives predominantly target new applications of hydrogen, but there is an obvious absence of a dedicated coalition bringing together companies from the sectors that already use hydrogen today: the chemical and refining sectors. Only the Mission Possible Partnership has activities within the chemical sector and, more concretely, on ammonia production, but does not have any specific commitment. An initiative of this nature, with a shared objective of adopting low-emission hydrogen in existing applications, presents a ripe opportunity to expedite the rapid scaling up of low-emission hydrogen production and use in the short term.

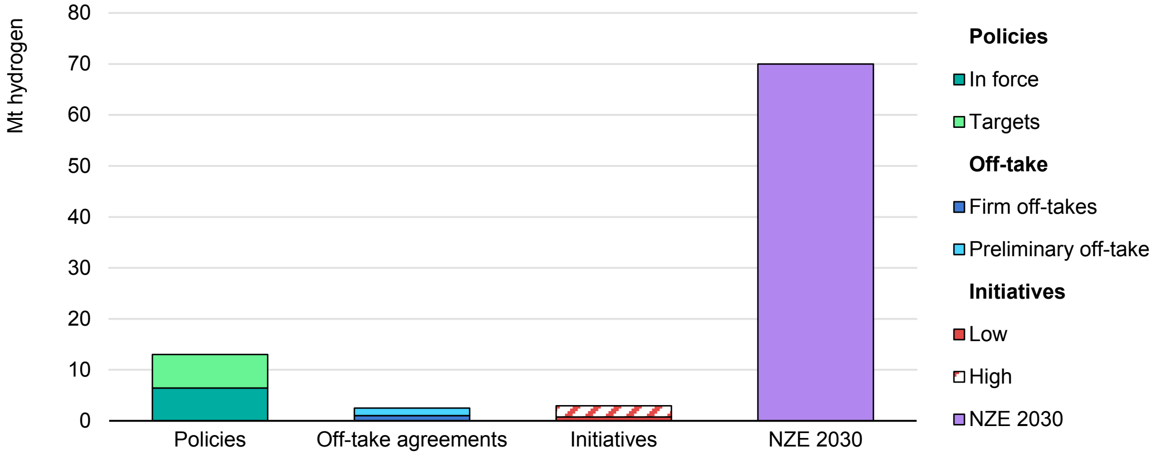
Closing the ambition and implementation gap with the Net Zero Emissions by 2050 Scenario

While governments and the private sector have taken first steps to promote the adoption of low-emission hydrogen, these actions are insufficient to align with governments' climate objectives and to scale up low-emission hydrogen production accordingly, which is crucial to drive down costs.

The gap between current actions and the demand for low-emission hydrogen required to put the world on a pathway compatible with achieving net zero emissions by 2050 is even more significant when considering the speed of deployment needed in the short term. In the NZE Scenario, demand for low-emission hydrogen reaches 70 Mt by 2030, compared to the 3-14 Mt that could be achieved through current government and private sector activities. The disparity is even more pronounced when compared to off-take deals already signed by the private sector (Figure 2.15). In this context, there is clearly an urgent need for bolder action to stimulate demand for low-emission hydrogen.

Governments must take the lead and implement policies that encourage action in the private sector, combining support measures with regulatory frameworks to enforce the adoption of low-emission hydrogen in sectors where it is the only decarbonisation alternative: refining, ammonia production and methanol production. In other priority sectors such as steel, shipping, aviation and long-distance road transport, where alternative mitigation options exist (e.g. iron ore electrolysis in ironmaking; battery electric trucks), regulatory structures should also be designed to provide technology-neutral incentives for equivalent options. International regulatory bodies, such as the International Maritime Organization and the International Civil Aviation Organization, should also take action to accelerate the adoption of fuel standards and mandates of sustainable fuels in international transport, ensuring that all players are subject to the same rules, which can unlock large demands for hydrogen-based fuels in shipping and aviation. Policies addressing the fuel supply side (such as phasing out fossil fuel subsidies, which the IEA has long been recommending) can also help bridge the cost gap between low-emission hydrogen and fossil-based alternatives.

Figure 2.15 Potential demand for low-emission hydrogen from announced policies and targets, private off-take agreements, commitments of international co-operation initiatives and the Net Zero Emissions by 2050 Scenario, 2030



Notes: NZE = Net Zero Emissions by 2050 Scenario. In "Initiatives", the dashed area corresponds to the range between the most conservative (low) and boldest (high) estimates of the demand that can be generated by international initiatives.

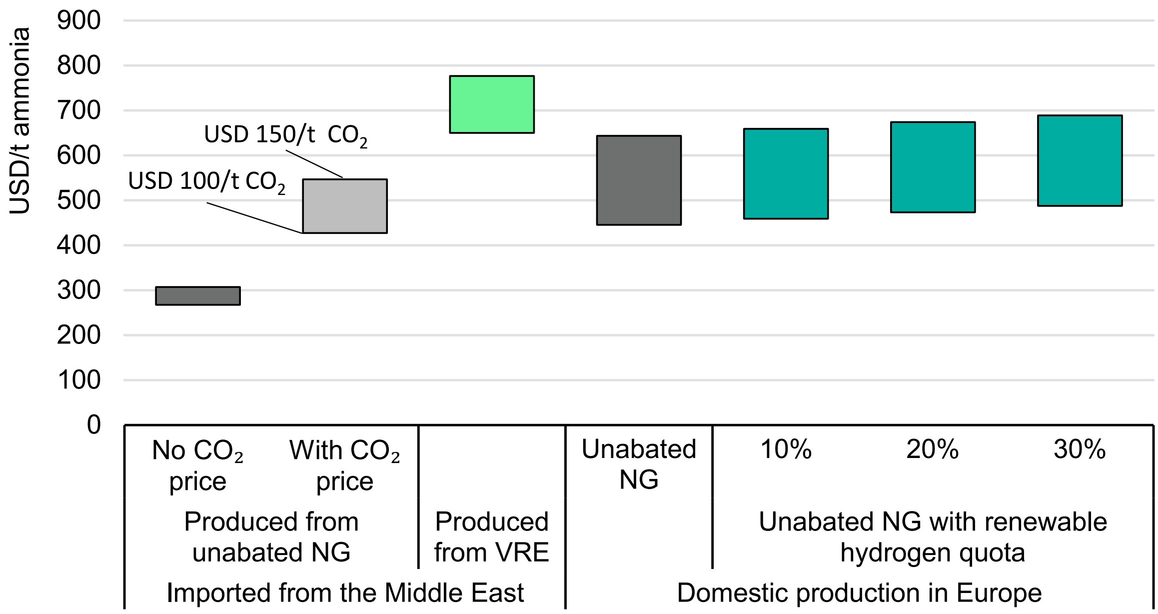
Actions from governments, international co-operation initiatives and the private sector fall very short of the effort needed to get on track with the NZE Scenario.

Public procurement is another potentially powerful policy tool that governments can leverage to create demand for low-emission hydrogen. Public procurement represents on average 13-20% of GDP today, and governments can make use of this purchasing power to create demand for low-emission and near-zero emission materials and products in infrastructure projects (such as steel or cement) that can be produced using low-emission hydrogen, for example. It can also be used to create demand for alternative fuels (which can include hydrogen and hydrogen-based fuels) for public transport and public service (e.g. refuse collection) and other government vehicles (potentially even including applications in shipping and aviation).

A one-size-fits-all approach will not work for stimulating demand in all sectors. In some areas, where hydrogen end-use technologies are not yet commercially available, incentives combined with innovation and demonstration efforts may be more appropriate. In other sectors where technologies are readily available, more coercive measures like mandates and ambitious emissions standards can drive faster adoption.

However, imposing regulations for the adoption of low-emission hydrogen in industries with globally traded products, such as steel and fertilisers, requires caution. The individual adoption of stringent regulations at the national level, without co-ordination across countries to ensure a level playing field, can impact the competitiveness of these industries (Figure 2.16), which could struggle to find consumers outside of certain niche markets where consumers are willing to pay a premium for low-emission or near-zero emission products. This may result in industry relocation to other areas where these measures are not adopted and where regulations to address GHG emissions are laxer, leading to an increase in global emissions and, ultimately, slowing down the adoption of low-emission hydrogen. The adoption of carbon accounting mechanisms for imported products can help to prevent this risk, but such regulations should comply with World Trade Organization principles to make sure that they do not constitute a barrier to global trade.

Figure 2.16 Domestic production cost of ammonia in Europe considering different shares of renewable hydrogen compared with the cost of delivered ammonia from the Middle East



Notes: VRE= variable renewable energy sources; Unabated NG = natural gas-based production without carbon capture, utilisation and storage. Cost of domestic production in Europe computed with a natural gas price of USD 1.5-6/MBtu, CO_2 price of USD 100-150/t CO_2 and renewable electricity price of USD 25-40/MWh. To ensure a minimum load of 85% for the synthesis process when fed by renewable hydrogen, the cost of compressed hydrogen storage is included. Cost of ammonia imported from the Middle East computed with a natural gas price of USD 1.5-3/MBtu and a transport cost of USD 20/t NH_3.

Sources: Based on data from McKinsey & Company and the Hydrogen Council; NREL (2022); IEA GHG (2017).

Unilateral adoption of domestic quotas for low-emission hydrogen in supply chains exposed to global trade without additional measures to reduce the low-emission premium can affect the competitiveness of local industries.

Reaching the scale-up needed to achieve climate goals requires more than just individual action. Governments will need to work together and co-ordinate action to unlock the necessary level of demand. Agreeing on minimum quotas for low-emission hydrogen use in sectors with commercially available end-use technologies, or those expected to become commercial by 2030, can provide the confidence needed in markets to significantly boost demand while helping to tackle the risks of industry relocation and carbon leakage. The NZE Scenario can provide guidance for establishing such quotas. The adoption of quotas for the use of low-emission hydrogen in refining, ammonia production and methanol production in line with the NZE Scenario can unlock a level of demand equivalent to 40-50% of current government production targets and 35-65% of the potential production from announced projects for low-emission hydrogen production by 2030 (Table 2.3). This would allow for a significant scale-up of low-emission hydrogen production and drive down its production cost to enable wider uptake in other sectors, thereby reducing the economic burden on governments when helping to bridge premium costs.

Table 2.3 Low-emission hydrogen demand and share of sectoral hydrogen demand in refining, ammonia production and methanol production in the Net Zero Emissions by 2050 Scenario, 2030

Application	Low-emission hydrogen demand (Mt)	Share of low-emission hydrogen in total sectoral demand
Production of ammonia	3.5	15%
Production of methanol	3.5	20%
Refining	7.0	20%

Note: The share of low-emission hydrogen demand for ammonia is calculated excluding production equipped with CCU for urea synthesis.

These quotas could be complemented with quotas for low-emission fuels in shipping and aviation. The European Union has taken the first step in this direction by mandating the use of SAF (including RFNBO) as part of RefuelEU Aviation Initiative. In the NZE Scenario, almost 15% of shipping and aviation demand is met by low-emission fuels by 2030. These quotas will not send a direct demand signal for low-emission hydrogen and hydrogen-based fuels, but it can be expected that they would lead to important demands for low-emission hydrogen, nevertheless. For example, meeting just 0.5% of aviation demand with synthetic kerosene by 2030 could lead to close to 1 Mt of hydrogen demand.

International co-operation is vital in this endeavour. Countries should leverage existing platforms and forums, such as the Hydrogen Energy Ministerial, the Clean Energy Ministerial Hydrogen Initiative, the G7 and the G20, to foster dialogue, co-ordinate policies, and reach a global agreement on promoting low-emission hydrogen adoption.

In summary, achieving the necessary demand for low-emission hydrogen as quickly as possible requires a comprehensive approach that combines incentives, regulations, and international co-operation. Bold actions from governments and the private sector are crucial to drive up demand to a level consistent with a net zero emissions future.

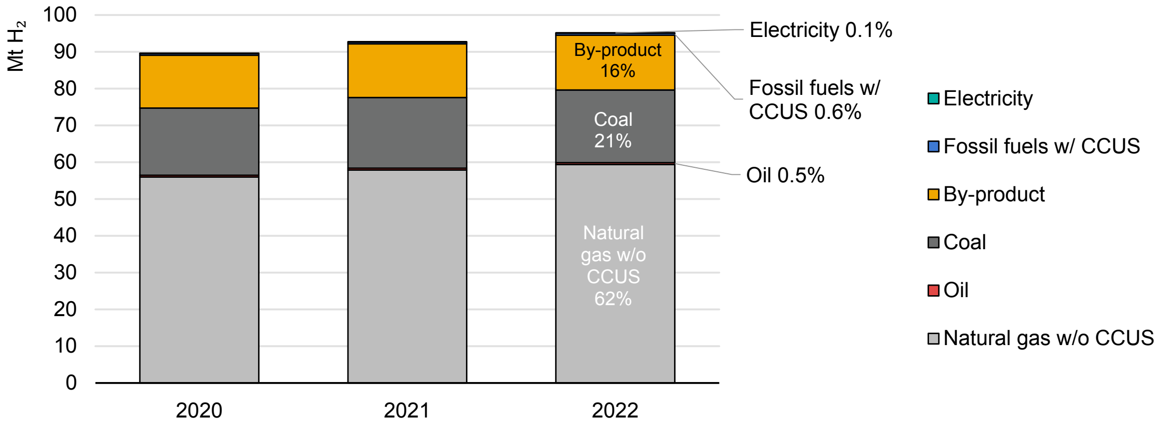
Chapter 3. Hydrogen production

Overview and outlook

Current status

Global hydrogen production reached almost 95 Mt in 2022, an increase of 3% compared to 2021 (Figure 3.1).[37] As in 2021, production was dominated by the unabated use of fossil fuels. Natural gas without carbon capture, utilisation and storage (CCUS) accounted for 62% of global production, while unabated coal, mainly located in China, was responsible for 21% of global production. By-product hydrogen, which is produced at refineries and in the petrochemical industry during naphtha reforming, and often used for other refinery and conversion processes (e.g. hydrocracking, desulphurisation), accounted for 16% of global production.

Figure 3.1 Hydrogen production by technology, 2020-2022



Note: CCUS= carbon capture, utilisation and storage.

Global hydrogen production grew by 3% in 2022 to reach 95 Mt, but low-emission hydrogen production accounted for less than 1% of all production.

Low-emission hydrogen production in 2022 was less than 1 Mt (0.7% of global production), very similar to in 2021 and almost entirely from fossil fuels with

[37] This includes 75 Mt of pure hydrogen production and around 20 Mt H_2 mixed with carbon-containing gases in methanol production and steel manufacturing. It excludes around 30 Mt H_2 present in residual gases from industrial processes used for heat and electricity generation: as this use is linked to the inherent presence of hydrogen in these residual streams, rather than to any hydrogen requirement, these gases are not considered here in the demand and supply of hydrogen. By-product hydrogen from the chlor-alkali industry is not included here.

CCUS.[38] Production from water electrolysis continued to be relatively small, still below 100 kt H_2 in 2022, which represents 35% growth compared to the previous year.

On a regional level, China accounted for almost 30% of global production, reflecting large domestic demands for refineries and the chemical industry. More than 70% of global production was in China, the United States, the Middle East, India and Russia in 2022 (in descending order by share of production).

Outlook up to 2030

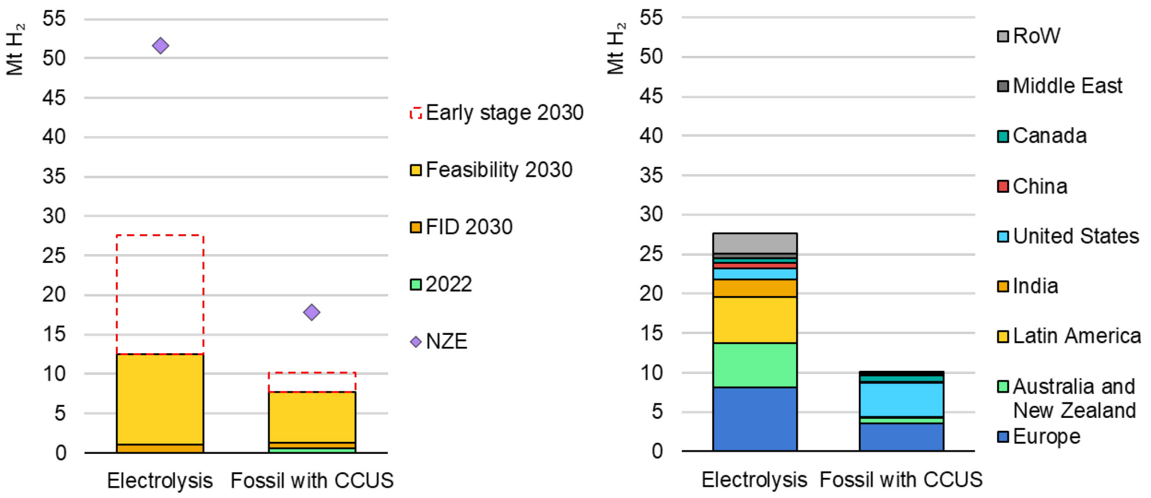
A large number of low-emission hydrogen production projects are under development according to our tracking of announced projects. Annual production of low-emission hydrogen could reach more than 20 Mt in 2030, if all the announced projects for hydrogen produced from water electrolysis and fossil fuels with CCUS are realised[39] (Figure 3.2). The corresponding number in the Global Hydrogen Review 2022 (GHR 2022) was 16 Mt H_2 by 2030[40], implying a more than 30% increase in the announced projects of low-emission hydrogen production within one year.

Half of the produced hydrogen from the announced projects by 2030 comes from projects that are today undergoing feasibility studies, followed by projects that are at very early stages (more than 45% in terms of production level). Projects that are currently under construction or have taken a final investment decision (FID) account for only 4% of the announced projects in terms of production. Of these projects, almost half are linked to existing hydrogen uses in refineries and the chemical industry (Figure 3.3). Electrolyser projects dominate among the announced hydrogen production projects: more than 70% of low-emission hydrogen production in 2030 could come from electrolysis. However, 55% of the announced electrolyser projects are at early stages of development. Given that further developing these projects takes time, efforts over the coming years will be critical to ensuring that these projects can become operational by 2030.

Based on the announced projects[41] so far, in terms of production Europe and Australia account for almost 30% and 20%, respectively, of all announced electrolytic hydrogen projects in 2030 (Figure 3.2 and Figure 3.4).

[38] See Explanatory notes annex for low-emission hydrogen definition in this report.
[39] This could increase to 38 Mt H_2, if projects at a very early stage of development (e.g. only a co-operation agreement among stakeholders has been announced) are included.
[40] The annual production of low-emission hydrogen in the GHR 2022, including projects at the very early stage of development, was 24 Mt by 2030.
[41] The regional discussion of announced projects includes early-stage projects.

Figure 3.2 Low-emission hydrogen production by technology route, maturity and region based on announced projects and in the Net Zero Emissions by 2050 Scenario, 2030



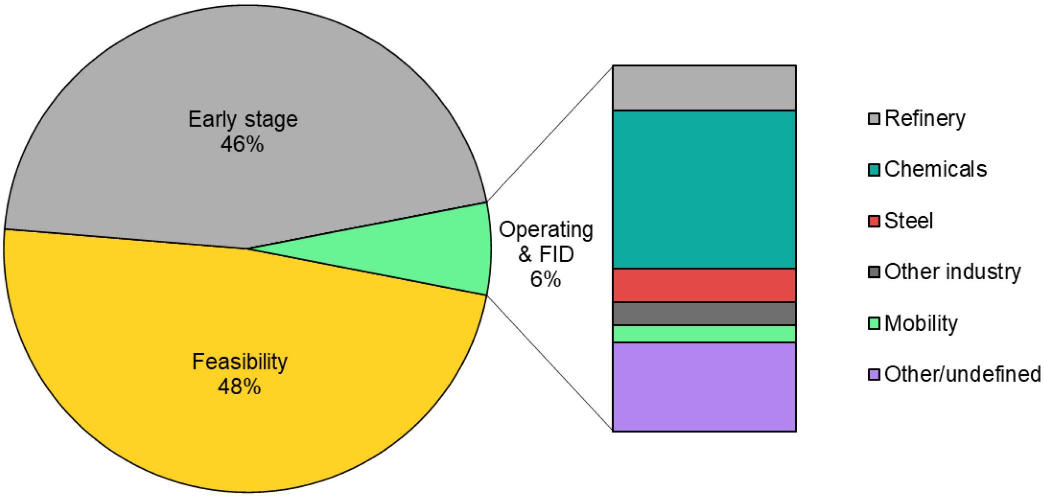
Notes: FID = Final investment decision; CCUS = carbon capture, utilisation and storage; NZE = Net Zero Emissions by 2050 Scenario; RoW = rest of world. In the left-hand side figure, the '2022' label refers to operational projects, and the label FID 2030 includes projects that are under construction and projects that have reached FID. "FID" includes projects that have reached at least the FID, therefore under-construction projects are also included; "Feasibility" includes projects undergoing a feasibility study; "Early stage" includes projects at very early stages, such as those in which only a co-operation agreement among stakeholders has been announced. The right-hand side figure includes operational projects and projects that have taken FID, at advanced planning and at early stages.

Source: IEA Hydrogen Projects, (Database, October 2023 release).

Announced projects correspond to low-emission hydrogen production of 20 Mt, and 38 Mt when early-stage projects are included, but only 4% have reached final investment decision or are under construction.

The front runners in Europe are Spain, Denmark, Germany and Netherlands, with the four countries accounting for almost 55% of Europe's electrolytic hydrogen production. In 2022, in the second round of funding approvals for hydrogen-related Important Projects of Common European Interest (IPCEI), the European Commission focused on projects boosting the supply of low-carbon and renewable hydrogen and announced the first auctions of the European Hydrogen Bank for the end of 2023. Taking advantage of its good renewable sources for solar PV and wind, Australia's low-emission hydrogen production via water electrolysis could reach close to 6 Mt by 2030, with many of the projects aiming to reach export markets. Hydrogen production from electrolysis in Latin America could reach almost 6 Mt by 2030 based on announced projects, in particular in Chile (representing 45% of the electrolytic hydrogen production of the announced projects in Latin America), Brazil and Argentina (representing a 30% of the electrolytic hydrogen production). In the United States, 9 GW of electrolyser projects were announced in the past 12 months following the announcement of the Clean Hydrogen Production Tax Credit. In addition, significant development of electrolysers was realised in China. According to the latest announcements, many projects in China are currently under construction (almost 40% in terms of production level) and further project developments are expected for the future (Box 3.1). In Africa, hydrogen production from announced electrolyser projects could reach 2 Mt by 2030. More than 20 projects with an electrolyser capacity at or above 100 MW have been announced in Kenya, Mauritania, Morocco, Namibia and South Africa, with 9 projects having a planned electrolyser capacity in the order of 1 000 MW or more.

Figure 3.3 Low-emission hydrogen production by status and by sector based on announced projects, 2030



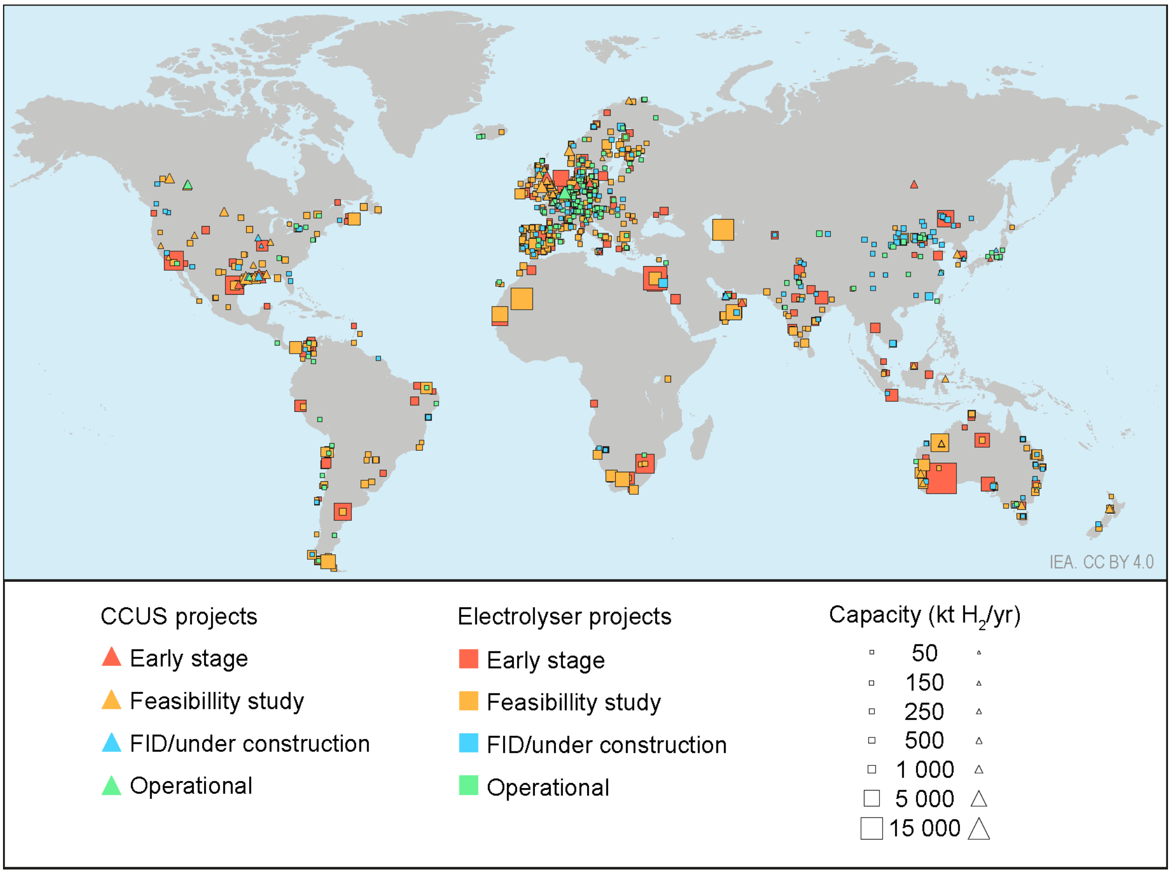
Notes: FID = Final investment decision. “Operating & FID” includes projects that are operating and that have reached at least FID, therefore projects under construction are also included; “Feasibility” includes projects undergoing a feasibility study; “Early stage” includes projects at very early stages, such as those in which only a co-operation agreement among stakeholders has been announced. “Other/undefined” includes projects for which the use has not been specified, and other hydrogen uses.

Low-emission hydrogen production projects under construction or having reached final investment decision are often linked to existing hydrogen uses.

For hydrogen production from fossil fuels with CCUS, the United States could account for 4 Mt by 2030, based on announced projects. Europe could reach more than 3 Mt H_2 in 2030, with projects produced primarily located in the United Kingdom, the Netherlands and Norway.

Production from the announced projects corresponds to more than half of the low-emission hydrogen production of almost 70 Mt H_2 by 2030 envisaged in the Net Zero Emissions by 2050 Scenario (NZE Scenario). The remaining gap of 30 Mt H_2 between all the announced projects and the NZE Scenario is composed of 25 Mt H_2 for production via electrolysis, and 8 Mt H_2 for production from fossil fuels with CCUS.

Figure 3.4 Map of announced low-emission hydrogen production projects



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

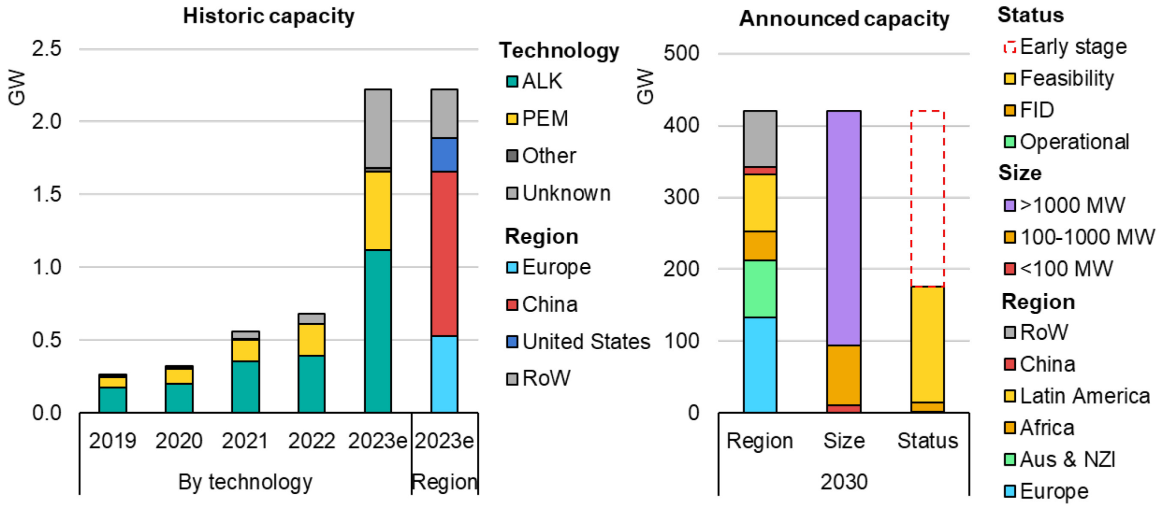
Announced projects are so far concentrated in Europe and Australia, but a growing number are planned in Africa, China, India, Latin America and the United States.

Electrolysis

Current status

Water electrolysis (hereafter simply referred to as electrolysis) accounts for just 0.1% of today's global hydrogen production, but installed capacity and the number of announced projects have been growing rapidly in recent years. About 600 projects with a combined capacity of more than 160 GW have been announced since the GHR 2022. By the end of 2022, the global installed water electrolyser capacity for hydrogen production reached almost 700 MW, a 20% increase compared to the previous year (Figure 3.5).

Figure 3.5 Global electrolyser capacity by technology, 2019 – 2023, and by region, size and status based on announced projects by 2030



Notes: ALK = alkaline electrolysers; FID = final investment decision and under construction; PEM = proton exchange membrane electrolysers; RoW = rest of world; Aus & NZl = Australia and New Zealand; 2023e = estimate for 2023 capacity, based on projects planned to start operations in 2023 and that have at least reached FID. "Other" technology refers to solid oxide electrolysis, anion exchange membrane electrolysis or a combination of different technologies. The unit is GW of electrical input. Only projects with a disclosed start year are included.

Source: IEA Hydrogen Projects, (Database, October 2023 release).

Global installed electrolyser capacity could reach more than 2 000 MW by the end of 2023. Based on announced projects, 175 GW could be reached by the end of the decade, and even 420 GW including early-stage projects.

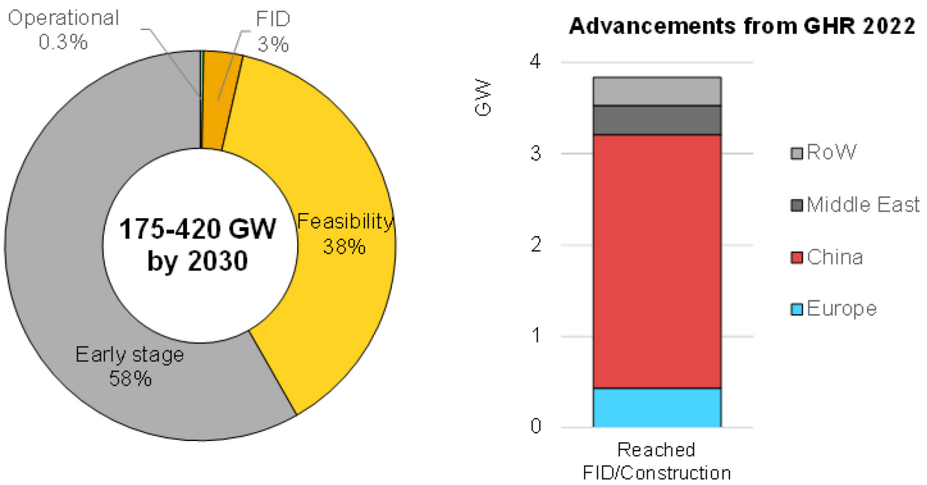
Plants with a combined capacity of 120 MW started operations in 2022. This is only roughly half of the new capacity additions seen in 2021; however, 2021 was an exceptional year that included commissioning of a single project in China with a capacity of 150 MW. China is likely to again lead the list of the largest electrolysers being commissioned in 2023, with a 260 MW plant by Sinopec having started operations in July 2023, and more than 550 MW of projects under construction. Based on projects that have at least reached FID or are under construction, installed global capacity could more than triple to 2 GW by the end of 2023 (equivalent to about 0.2 Mt hydrogen production), assuming all projects are realised as planned, though several projects are suffering from delays.

Alkaline electrolysers accounted for 60% of the installed capacity by the end of 2022, followed by proton exchange membrane (PEM) electrolysers with around 30%. Based on announcements, this is expected to change in the coming years, with PEM gaining market share over alkaline electrolysers, although many future projects have not yet decided or disclosed which electrolyser technology will be deployed. Solid oxide electrolysers (SOEC) represent less than 1% of installed capacity today. In terms of geographical distribution, China and Europe each accounted for one-third of the installed capacity at the end of 2022, while for the United States and Canada the combined share was 10%.

Rapidly growing number of announced projects

Based on announced projects, global installed electrolyser capacity could reach 175 GW by 2030, an increase of 30% compared to the announcements in the GHR 2022. The capacity in 2030 increases to 420 GW when projects at early stages of development[42] are also taken into consideration (Figure 3.6).

Figure 3.6 Electrolyser capacity in 2030 based on current announcements by status, and progress since the Global Hydrogen Review 2022



IEA. CC BY 4.0.

Notes: GHR = Global Hydrogen Review; FID=final investment decision; RoW = rest of the world. “FID” includes projects that are under construction and projects that have reached FID; “Early stages” includes projects at concept status, such as those in which only a co-operation agreement among stakeholders has been announced. The lower number in the capacity range excludes the “Early stage” projects. The percentage shares include “Early stage” projects. Only projects with a disclosed start year are included.

Source: IEA Hydrogen Projects, (Database, October 2023 release).

Based on all announced projects, electrolyser capacity could reach 420 GW by 2030, but more than half of the projects are at early development stages.

Europe could be home to one-third of this capacity, followed by Latin America and Australia with 20% each one. However, recent progress in China (Box 3.1) and the impact of the Inflation Reduction Act (IRA) in the United States are likely to change this picture, with these two countries expected to take a larger share of total installed capacity than can be seen in the announced projects today.

The realisation of all announced projects is still highly uncertain, as less than 4% of the capacity of all announced projects has reached FID or is under construction. Almost 40% of the capacity is undergoing or has completed a feasibility study.

[42] e.g. projects for which only a co-operation agreement among stakeholders has been announced.

Since the publication of the last edition of the Global Hydrogen Review in September 2022, more than 3.8 GW of electrolyser projects have reached FID or started construction. This is mainly due to construction starting on the NEOM Green Hydrogen Project in Saudi Arabia, which is planned to go online in 2026, and is the biggest project in the world to have started construction. Recently, financial closure has been achieved for the Green Hydrogen Project in Oman, expected to produce 100 kt of ammonia per year, and planned to have a capacity of 3.5 GW once at full scale.

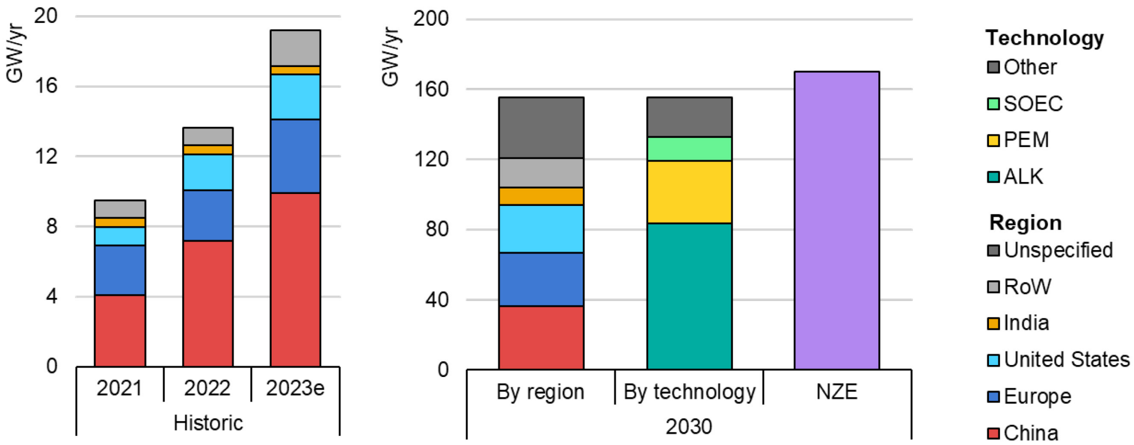
The scale-up in installed electrolyser capacity is also accompanied by a trend towards larger projects being announced. While the average size of electrolyser plants is about 12 MW today, it could grow to several hundreds of MW in few years and to 1 GW by 2030, with GW-scale projects representing more than 75% of announced capacity for 2030.

Electrolyser supply chains

By the end of 2022, the available manufacturing capacity publicised by electrolyser manufacturers reached as high as 14 GW/yr, half of which was in China, to serve a rapidly growing domestic market, and a further one-fifth in Europe (Figure 3.7). However, output to date has been much lower than this: we estimate it at just above 1 GW/yr in 2022 based on water-splitting projects entering operation and the historical market for chlor-alkali electrolysers, which continue to dominate factory output. Nonetheless, there appears to be sufficient capacity to realise the 1.1 GW of projects under construction for delivery in 2023 and 5 GW for 2024. Given the large gap between current output and stated manufacturing capacities by manufacturers, it also seems feasible that manufacturers could ramp up output by several gigawatts in two to three years if they receive orders from projects seeking to take advantage of financial incentives in North America and Europe.

Based on companies' announcements, global electrolyser manufacturing capacity could reach 155 GW/yr by 2030, with one-quarter of the manufacturing capacity located in China, one-fifth each in the United States and Europe, and 6% in India. However, 20% of the expansion plans by 2030 have been announced without a disclosed location, which means that the geographical distribution could change, for example if influenced by policy support to stimulate local demand and local manufacturing (such as the IRA in the United States, the Net Zero Industry Act in the European Union or the incentive schemes for electrolyser manufacturing in India).

Figure 3.7 Electrolyser manufacturing capacity by region and technology according to announced projects and in the Net Zero Emissions by 2050 Scenario, 2021-2030



Notes: ALK = alkaline electrolyser; NZE = Net Zero Emissions by 2050 Scenario; PEM = proton exchange membrane electrolyser; RoW = rest of the world; SOEC = solid oxide electrolyser. The manufacturing capacity for 2023 is an estimate including facilities under construction that are planned to be operational by the end of 2023.
Source: IEA analysis based on announcements by manufacturers and personal communications.

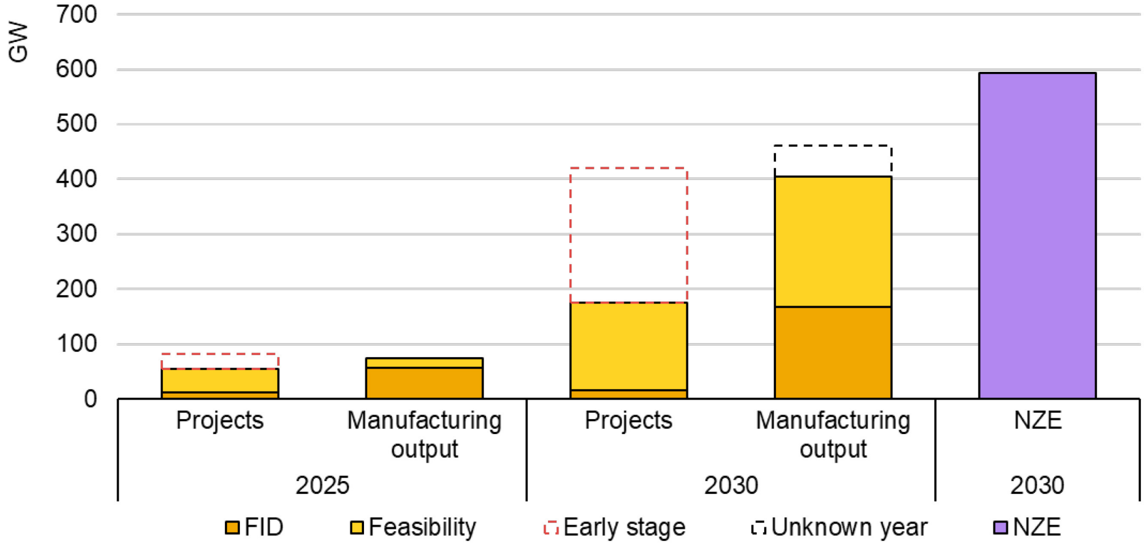
Electrolyser manufacturing capacity almost doubled between 2021 and 2023. Announced plants could cover 90% of the needs in the Net Zero Emissions by 2050 Scenario.

Three-quarters of manufacturing capacity today is for alkaline electrolysers – of which 70% is in China – while PEM and SOEC account for 2 GW/yr and 1.5 GW/yr, respectively. Part of the manufacturing capacity for these two technologies, however, is used to produce fuel cells in the same factories, given the technology similarities, which means that the capacity used for electrolysers may be lower. By 2030, PEM manufacturing capacity could grow to reach almost one-quarter of the global capacity, with the share of alkaline electrolysers declining though still dominant at 54%.

Only 8% of the announced manufacturing capacity has reached FID or is under construction. About 30% of the overall announced manufacturing capacity is an expansion of plants that already exist, or a later expansion of new manufacturing plants to be built, announced without a specific target year. Since planned expansions of existing plants often have shorter lead times compared to building a greenfield plant, companies may take more time to decide whether to move forward with these plans based on future demand developments. This adds further uncertainty on whether announced expansions will eventually be realised.

Overall, the announced manufacturing capacities of 155 GW/yr by 2030 represent 90% of the 170 GW of manufacturing capacity envisaged in 2030 in the NZE Scenario.

Figure 3.8 Global electrolyser capacity from announced projects, and cumulative output from announced manufacturing capacity compared to the Net Zero Emissions by 2050 Scenario, 2025-2030



Notes: FID = final investment decision; NZE = Net Zero Emissions by 2050 Scenario. The manufacturing output has been computed assuming an 85% utilisation rate of the cumulative announced manufacturing capacity, and one year between the full-scale operation of the manufacturing facility and the installation of the manufactured electrolyser. Manufacturing capacity announced without a disclosed target year has been allocated to 2030.

Source: IEA analysis based on announcements by manufacturers and personal communications, and on IEA Hydrogen Projects, (Database, October 2023 release).

Announced manufacturing capacity could be sufficient to support the deployment of announced electrolyser projects by 2030.

If all the announcements from manufacturers are realised on time and at scale, the potential output of the electrolyser manufacturing facilities would be sufficient to support the deployment of all the announced production projects by 2030 (Figure 3.8). If only the announced capacity that has reached financial closure (FID) or is under construction (i.e. is committed) is considered, the potential output would be not only sufficient to satisfy the production projects that have reached FID, but is such that by 2030 it could also cover the demand of electrolysers from production projects currently undergoing feasibility studies. The imbalance between committed production projects and manufacturing capacity could, however, mean that if production projects for 2030 that are currently at feasibility study stage progress more slowly than planned, this would result in 2030 in a low utilisation rate of the committed manufacturing plants.

The cost of electrolytic hydrogen

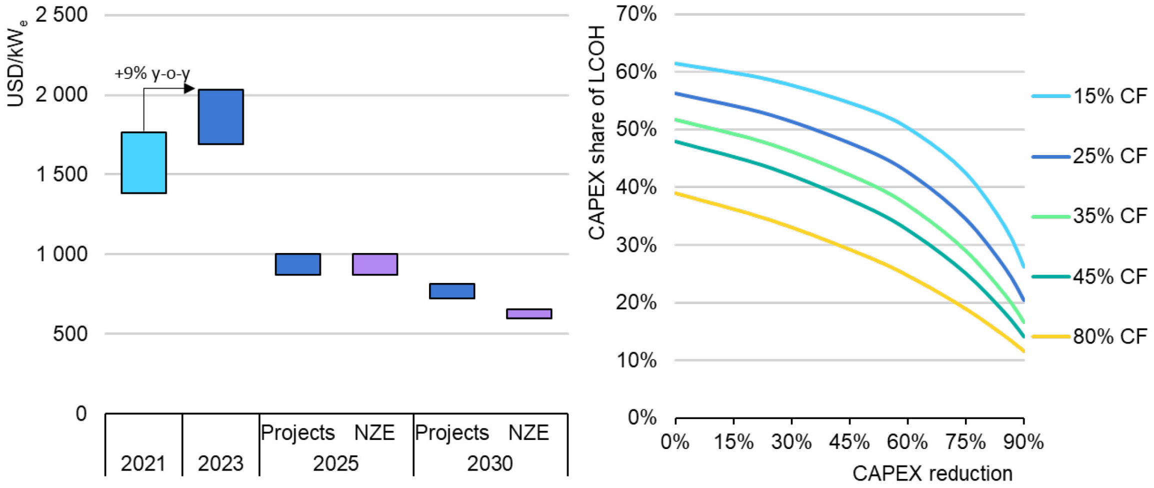
The installed cost of electrolysers has increased significantly in the past few years due to increases in materials and labour costs. The capital cost for an installed electrolyser (including the equipment, gas treatment, plant balancing, and engineering, procurement and construction cost) ranges between USD 1 700/kW and USD 2 000/kW (for alkaline and PEM respectively, based on data from industry and project developers), a year-on-year increase of about 9% compared to the capital cost range observed in 2021. However, in Europe, some project developers have observed even higher inflation values, up to 40% in certain cases. Alkaline electrolysers manufactured in China are, in terms of CAPEX, much cheaper than those manufactured in Europe or North America, at around USD 750-1 300/kW for an installed electrolyser, but could be as low as USD 350/kW according to some sources. The cost figure reflects technical standards and conditions in China. For exports, adjustments to be made to Chinese electrolysers to comply with standards in other countries may lead to higher costs. The inflation on the CAPEX of the electrolysers could translate into a 20% cost increase in the levelised cost of hydrogen production (assuming all other parameters remain constant), as the CAPEX today represents the main cost component.

Recent inflation and increases in labour cost have had a considerable impact on projects under development, whose first cost estimates have been revised upwards in several cases (see Chapter 5 Investment, finance and innovation). The cost of Saudi Arabia's NEOM Green Hydrogen project has risen from USD 5 billion to USD 8.5 billion, according to a statement from the beginning of 2023, due to inflation, supply chain-related cost increases, and an enlargement of the project scope to include, for example, transmission lines and some other infrastructure equipment. Similarly, the German Bad Lauchstädt Energy Park project has seen costs rise by 50% from the first estimate.

Based on the deployment of electrolysers in the next decade envisaged in current announcements, the capital cost could decrease due to economies of scale and mass production.[43] Based on capacity deployment of the announced projects, the cost of an installed electrolyser could go down compared to 2023 by 50% by 2025 and by 60% by 2030, reaching about USD 720-810/kW (Figure 3.9). Based on the electrolyser installations required to meet needs in the NZE Scenario, the cost reduction could reach 65-70% by 2030, leading to below USD 600/kW installed cost. Such a cost reduction alone could halve the share of CAPEX in the levelised cost of hydrogen (assuming all the other parameters remain constant) to around 25%.

[43] To assess the cost reduction, a learning rate of 18% has been used for the electrolyser stack, representing about half of the system cost, and between 5-12% for the other components and the balance of plant.

Figure 3.9 Evolution of electrolyser installed capital costs based on deployment from announced projects and in the Net Zero Emissions by 2050 Scenario, 2021-2030, and the share of capital cost in the levelised cost of hydrogen production



Notes: CAPEX = capital expenditure; CF = capacity factor; LCOH = levelised cost of hydrogen; NZE = Net Zero Emissions by 2050 Scenario; y-o-y = year-on-year variation. Left-hand side chart: "Projects" refers to the capacity deployed according to announced projects, which is 55 GW by 2025 and 175 GW by 2030; in the case of the NZE Scenario, this is 590 GW by 2030. The learning rate for the electrolyser stack is 18%, while for the other components it is 5-12%. Right-hand side chart: electricity cost of USD 20/MWh, electrolyser efficiency of 69% lower heating value, 8% cost of capital.

Sources: IEA analysis based on data from McKinsey & Company and the Hydrogen Council, communications with companies and the IEA Hydrogen Projects, (Database, October 2023 release).

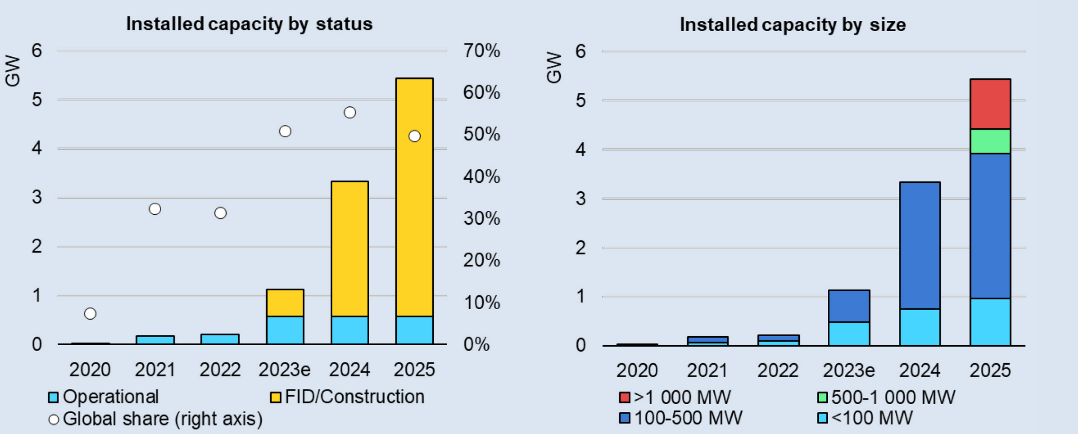
While electrolyser CAPEX increased in 2023 by 15% compared to 2021, CAPEX could be reduced by 60-70% by 2030.

Box 3.1 Electrolysis development in China

China currently produces more hydrogen than any other country around the world, with around 33 Mt produced in 2020, mainly from coal and natural gas, but recently significant growth has been realised in the production of hydrogen through water electrolysis. By 2022, 30% of global electrolyser capacity was installed in China. Since the beginning of 2023, China has made significant progress on hydrogen production through water electrolysis, and by the end of the year, the installed electrolyser capacity is expected to reach 1.1 GW, which would represent 50% of the global share. As of September 2023, half of this expected capacity is already in operation, while the rest is under construction.

Besides the strong growth in total installed electrolyser capacity, one of the world's largest electrolyser plants is going to be commissioned by the end of 2023; the Chifeng Ammonia Demonstration Project, with a yearly hydrogen production of 24 200 t H_2/yr (around 140 MW of electrolyser capacity). By 2024, 8 electrolytic hydrogen projects, which are currently under construction with electrolyser capacity greater than 125 MW are planned to start their operation in China next year. The electrolytic hydrogen project planned by Sinopec at its chemical facility in Ordos is one of the 8 hydrogen projects that are under construction, and it could be among the largest in the world, with 30 kt of annual hydrogen production (corresponding to about 350 MW of electrolysis, assuming a 50% capacity factor). Project announcements for electrolyser developments in China represent significant growth in the coming years, following wider global trends. Compared to 2023, the expected installed electrolyser capacity in China is set to triple to 3.3 GW by 2024, and to reach almost 5.4 GW by 2025.

Electrolyser capacity in China



Notes: FID/Construction = projects that have reached final investment decision (FID) or are under construction. Electrolyser capacity from 2023 to 2025 includes announced projects under construction or that have reached FID, assuming they will start operation based on schedule.

Source: IEA Hydrogen Projects, (Database, October 2023 release).

Furthermore, the average project size is growing fast: the number of projects with a capacity in the range of 100-500 MW is increasing in China. About 60% of the announced projects in 2023 are included in this category. An example is the Kuqa project from Sinopec, with a capacity of 260 MW and having started operation in June 2023. Larger-scale facilities of 500-1 000 MW are planned to be installed from 2025 onwards. By that year, giga-scale projects will represent almost 20% of the capacity that has at least reached FID. Besides the progress in electrolyser deployment, Chinese companies have also developed larger and more efficient electrolysers. In December 2022, Peric Hydrogen Energy Technologies presented the largest single unit hydrogen alkaline electrolyser, with a hydrogen capacity of 2 000 Nm^3/h or about 9 MW[44], and Longi Hydrogen unveiled in February 2023 a new alkaline model that – with a direct current electricity consumption of 4 kWh/Nm^3 (corresponding to 44.5 kWh/kg H_2) – is more efficient than most electrolysers on the market.

[44] Assuming an electricity demand of 52 kWh per kg H_2 or 4.7 kWh per Nm^3 H_2.

Fossil fuels with CCUS

Sixteen hydrogen facilities[45] around the world are equipped with CCUS, capturing around 11 Mt CO_2 per year. Most facilities are retrofitted hydrogen production units in refining and fertiliser production in North America, with first operation dating from the early 1980s. Only around 1 Mt of the captured CO_2 is injected in dedicated storage (at the Quest facility in Canada), and the remainder is injected for enhanced oil recovery (EOR) or used in applications such as the food and beverage industry or for boosting yields in greenhouses. Moreover, most facilities were retrofitted with partial capture, meaning only process emissions which have a high concentration of CO_2 are captured (Box 3.2). This results in only around 0.6 Mt of H_2 production qualifying as low-emission out of the 0.8-1.2 Mt produced[46], with 0.35 Mt from natural gas reforming (4 Mt CO_2 per year captured), and 0.25 Mt from coal and oil gasification (7 Mt CO_2 per year captured).

Hydrogen is one of the leading applications in CCUS deployment plans. More than one-quarter of CO_2 capture capacity under construction or in planning involves hydrogen or ammonia production across a range of applications, including dedicated production, refineries, fertiliser and iron and steel.

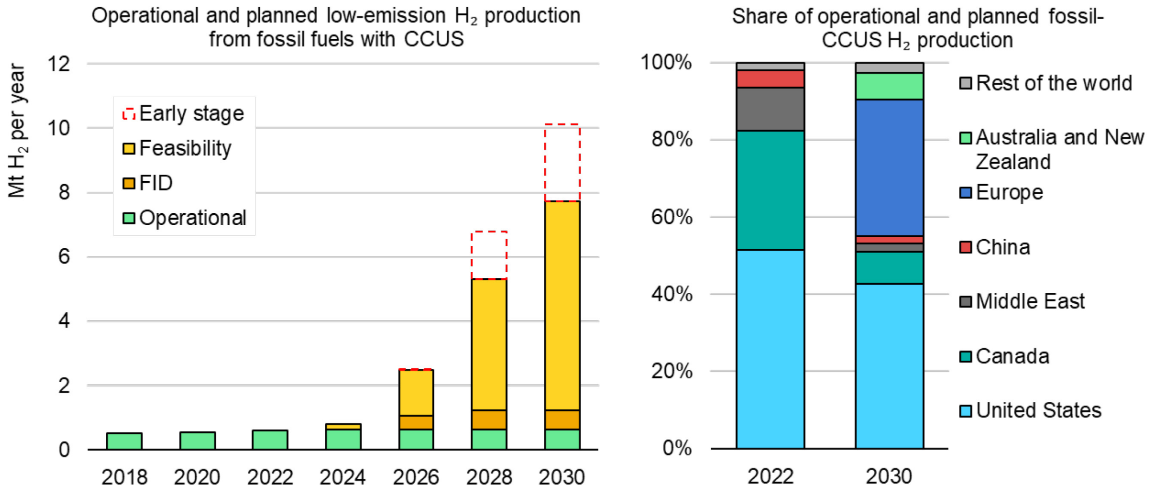
In the United States, while CO_2 demand for EOR was the primary driver for the first plants to capture emissions, the 45Q tax scheme first introduced in 2008 and increased through the IRA in 2022 up to USD 85 per tonne of CO_2 stored (around USD 0.80/kg H_2[47]), and up to USD 60 per tonne of CO_2 used (around USD 0.55/kg H_2), continues to support development, with more than 30 hydrogen projects with CCUS currently in planning. In Canada, the sector is benefiting from both CCUS and "clean" hydrogen investment tax credits, as well as funding for carbon storage hubs. In Europe, the United Kingdom is leading gas-CCUS hydrogen project development, supported by government-funded industrial decarbonisation programmes, followed by the Netherlands and Norway. In total, Europe could account for around 40% of low-emission production by 2030.[48]

If all announced projects are realised, low-emission hydrogen production from fossil fuels with CCUS could increase almost fifteen-fold from around 0.6 Mt per year in 2022 to around 9 Mt per year by 2030, with potential to increase to 12 Mt CO_2/yr if accounting for very early-stage projects (Figure 3.10). The vast majority comes from gas reforming, and less than 1 Mt from coal or oil gasification.

[45] Only projects with a capture capacity above 100 000 t CO_2 per year are considered here.
[46] Low-emission hydrogen production is estimated from the plant CO_2 capture capacity, and therefore only includes hydrogen production for which CO_2 is captured and stored. The range of total hydrogen production is estimated assuming a 40-60% overall unit capture rate for gas-based production and 90-95% for coal and oil-based production (Box 3.2), including projects capturing CO_2 for utilisation.
[47] Assuming gas-based production, 0.9105 kg CO_2 emitted per Nm^3 H_2 and 90% capture rate.
[48] This could decrease to one-third, if projects at a very early stage of development (e.g. only a co-operation agreement among stakeholders has been announced) are included.

This is still around10 Mt per year short of the circa 17 Mt of low-emission hydrogen production from fossil fuels with CCUS needed in 2030 in the NZE Scenario.

Figure 3.10 Production of low-emission hydrogen from fossil fuels with carbon capture utilisation and storage, historical and from announced projects, 2018-2030



Notes: CCUS = carbon capture, utilisation and storage; FID = final investment decision. FID refers to projects under construction or which have at least taken FID. Only includes projects with an announced operating date before 2030, assuming they will start operation on schedule.
Source: IEA Hydrogen Projects, (Database, October 2023 release).

Despite recent momentum, planned carbon capture, utilisation and storage-based hydrogen production remains low, and is concentrated in North America and Europe.

Projects under development are likely to need further policy and financial support to come to fruition. To date, only 6% of planned production for 2030 is currently under construction, though 2 of the 11 FID taken for CCUS-based projects in 2022 were for merchant hydrogen or ammonia production, which could suggest higher investor confidence in the sector.

Box 3.2 Can high plant capture rates be achieved?

Along with low methane emissions from fuel supply, high plant capture rates are essential to minimise residual emissions from fossil fuel-based hydrogen-CCUS production routes, or maximise CO_2 removal from biomass-based production (see section Emerging production routes below).

While capture efficiencies as high as 99% can be achieved with marginal additional energy input, overall plant capture rates also depend on process configuration and point of capture. Most operating steam methane reforming (SMR) facilities today operate at partial capture: only the CO_2 in the shifted syngas is captured, and not the CO_2 resulting from fuel combustion from the reformer furnace. This typically results in overall plant capture rates between 40% and 60%.

Process modelling studies have shown that plant capture rates of 96% and up to 99% can be achieved in a SMR plant by burning the unconverted off-gas with natural gas in the reformer furnace, and capturing CO_2 from the furnace exhaust, at levelised costs 50-60% higher than unabated SMR. In the autothermal reformer (ATR) process, most of the process CO_2 is available for capture in the shifted syngas, resulting in overall capture rates between 93-98%. The gas partial oxidation (POx) process developed by Shell is reported to yield overall plant capture rates up to 99%. Plant capture rates between 94% and 98% have also been simulated for coal gasification. To date, no operational plant has achieved these levels of capture, but two ATR projects targeting 90-95% capture are currently under construction in North America (see Chapter 5 Investment, finance and innovation).

Supply chain challenges for fossil-based hydrogen production with CCUS

Large-scale hydrogen production with CCUS does not face the same supply chain manufacturing constraints as electrolytic hydrogen. While large-scale hydrogen plants require mass-manufactured equipment such as compressors, pumps, fans, heat exchangers, separation columns and storage tanks, the manufacturing of these devices can benefit from synergies with other industries in which this equipment has been used for decades, notably oil and gas, chemicals and power generation. Producers can therefore access a large and diverse pool of suppliers located in different regions with well-established manufacturing facilities and supply chains.

Plant and infrastructure development lead times for the plant are likely to be the main bottleneck. Given that most operating plants are capital-intensive first-of-a-kind facilities, project lead times have historically been long, ranging from 1.5 to 10 years, with an average of around 4 years. Permitting and financing often constitute an important hurdle, taking on average almost as long as construction. Projects that require the development of new CO_2 management infrastructure for CO_2 transport and storage also tend to have longer lead times, due to long lead times associated with developing and permitting new storage resources, or the difficulty of co-ordinating infrastructure with capture developments. This was the case of the Alberta Carbon Trunk Line project, for example, which took around 10 years to reach commissioning.

Siting new hydrogen facilities close to industrial clusters can leverage local hydrogen demand and help share construction costs for CO_2 transport and storage infrastructure with other emitters, which could cut overall project lead times once infrastructure is in place. Around two-thirds of planned CO_2 capture capacity for hydrogen production are being developed as part of CO_2 transport and storage hubs catering for multiple industrial sources. Co-ordination of capture and infrastructure developments within these CCUS hubs, and design of legal and regulatory frameworks which are fit for purpose, will be crucial to avoid delays.

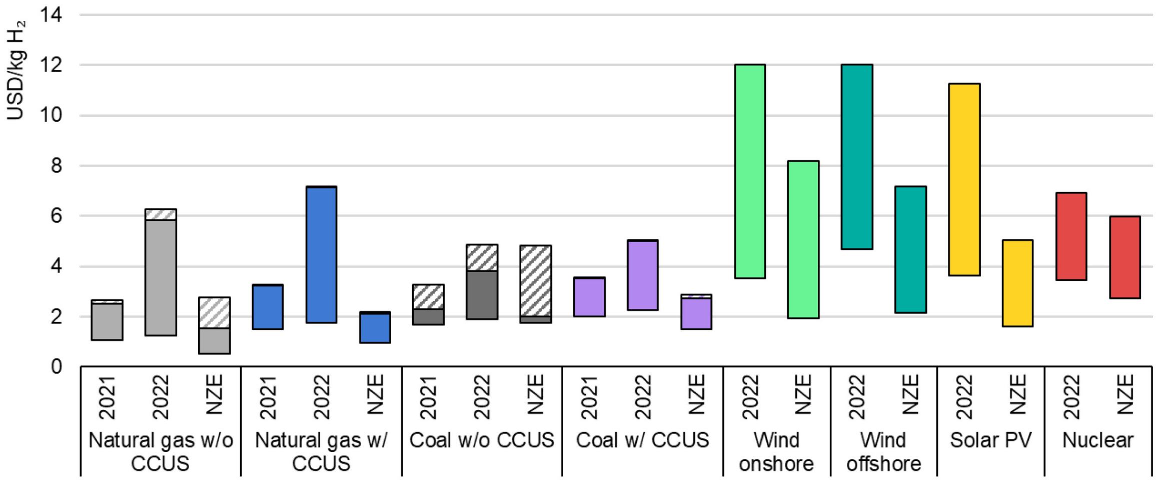
Comparison of different production routes

Hydrogen production costs

The cost of hydrogen production depends on the technology and cost of the energy source used, which usually has significant regional differences. Prior to the global energy crisis sparked by Russia's invasion of Ukraine, the levelised cost of hydrogen production from unabated fossil-based sources was in the range of USD 1.0-3.0/kg H_2 (Figure 3.11). In 2021, these production routes offered the cheapest option to produce hydrogen, compared with the use of fossil fuels with CCUS (USD 1.5-3.6/kg H_2) or the use of electrolysis with low-emission electricity (USD 3.4-12/kg H_2).

The cost of hydrogen produced using electrolysis is driven by the capital cost of electrolysers and the cost of the electricity used to power the electrolyser. As discussed above, the capital costs of electrolysers are set to decrease significantly in the short term, thanks to economies of scale and further technology innovation. The cost of renewable electricity has already decreased sharply in the last decade (80% reduction in the cost of solar modules between 2010 and 2020). The recent increases in commodity prices may slow down further cost declines in the near term but are unlikely to stop them altogether over the longer term. If large-scale deployment takes place as envisaged in the NZE Scenario, the production costs of electrolytic hydrogen using electricity from solar PV could fall to USD 1.6/kg H_2 by 2030 in regions with excellent solar irradiation, such as Africa, Australia, Chile, China and the Middle East. While solar PV-based electrolysis could become the cheapest way to produce hydrogen by the end of the decade, locations with excellent wind resources (offshore or onshore) could also see a significant drop in the levelised cost of hydrogen, reaching values under USD 2.1/kg H_2 in the north-west European region and under USD 2.3/kg H_2 in the United States.

Figure 3.11 Levelised cost of hydrogen production by technology in 2021, 2022 and in the Net Zero Emissions by 2050 Scenario in 2030



Notes: CCUS = carbon capture, utilisation and storage; PV = photovoltaic; NZE= Net Zero Emissions by 2050 Scenario in 2030. Solar PV, wind and nuclear refer to the electricity supply to power the electrolysis process. NZE values refer to 2030. Natural gas price is USD 5-15/MBtu for 2021, USD 6-36/MBtu for 2022 and USD 1-8/MBtu for 2030 NZE. Coal price is USD 40-180/tonne for 2021, USD 50-360/tonne for 2022 and USD 30-70/tonne for 2030 NZE. Solar PV electricity cost is USD 22-120/MWh for 2022, USD 13-80/MWh for 2030 NZE, with capacity factor of 12-35%. Onshore wind electricity cost is USD 25-130/MWh for 2022, USD 25-120/MWh for 2030 NZE, with capacity factor of 15-53%. Offshore wind electricity cost is USD 50-225/MWh for 2022, USD 30-125/MWh for 2030 NZE, with capacity factor of 32-67%. The cost of capital is 6%.

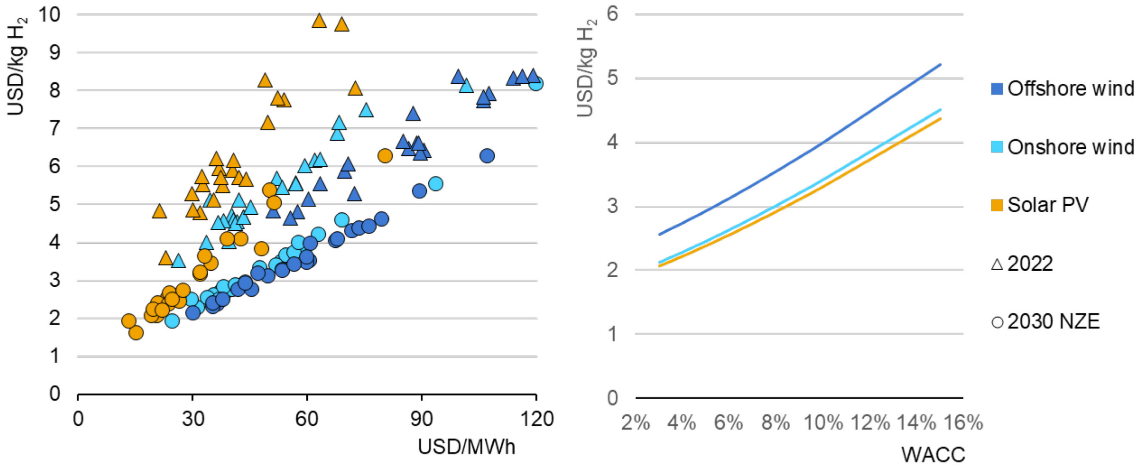
The dashed area represents the CO_2 price impact, based on USD 15-140/t CO_2 for the NZE Scenario. More techno-economic assumptions will be made available in a separate forthcoming Annex.

Sources: IEA analysis based on data from McKinsey & Company and the Hydrogen Council; IEA GHG (2014); NREL (2022); IEA GHG (2017); E4Tech (2015); Kawasaki Heavy Industries.

With natural gas prices subsiding from their 2022 highs, renewable hydrogen could become competitive with hydrogen from fossil fuels by 2030.

Electricity costs are a major component of the cost of hydrogen produced from electrolysis, accounting for 25-45% of total levelised cost from solar PV today. Low electricity costs and high capacity factors for the electrolyser favour lower electricity cost shares and lower overall hydrogen production costs, while reductions in electrolyser CAPEX increase the share of electricity costs in the total hydrogen production costs (Figure 3.9). Bringing down the cost of low-carbon electricity will be critical to reach low hydrogen production costs from electrolysis. Electricity costs of USD 20/MWh are equivalent to hydrogen costs of USD 1/kg H_2 (at 70% efficiency, lower heating value) – when leaving out any CAPEX and fixed OPEX costs for the electrolyser. Taking into account CAPEX and fixed OPEX, electricity costs would need to be even lower, as illustrated in Figure 3.12, in which hydrogen production costs from solar PV at locations with excellent solar conditions could fall to USD 1.6/kg H_2 by 2030, assuming drastic cost reductions for electricity to USD 13/MWh, that align with the NZE Scenario. Even with hydrogen costs approaching USD 1/kg H_2, it is important to keep in mind that hydrogen does not become a low-cost fuel: a hydrogen price of USD 1/kg H_2, when expressed in natural gas price units, translates into USD 8.8/MBtu, or in electricity price units into USD 30/MWh.

Figure 3.12 Levelised cost of hydrogen production based on different renewable electricity prices and on different costs of capital in the Net Zero Emissions by 2050 Scenario, 2030



Notes: NZE = Net Zero Emissions by 2050 Scenario; WACC= weighted average cost of capital. Left-hand side figure: points represent electricity and hydrogen production costs for different regions around the world, taking local renewable resource conditions into account. The cost of capital is 6%. Right-hand side chart: the capacity factor for solar PV is 28%, for onshore wind is 40% and for offshore wind is 56%. Techno-economic assumptions will be made available in a separate forthcoming Annex.

Renewable electricity costs and the cost of capital are key factors in hydrogen production costs. Doubling cost of capital from 5 to 10% increases production costs by almost 40%.

Hydrogen production from renewable electricity is a capital-intensive production route. Upfront investments are not only required for the electrolyser, but also for renewable electricity generation. For hydrogen production using electricity from solar PV, a 1%-point increase in the weighted average costs of capital (WACC) results in 2030 in the NZE Scenario roughly in a cost increase of around USD 0.2/kg H_2. In the current context of growing interest rates, increasing WACC can have a profound impact on the economic viability of projects and their hydrogen production costs. For example, a WACC increase from 5% to 10% results in an almost 40% increase in hydrogen production costs, depending on the renewable electricity source. For project developers in emerging and developing economies in particular, access to financing can be a major barrier, reflected in a WACC that is often higher compared to advanced economies. An increase in WACC from 6% to 15% for example would increase the cost of hydrogen production from solar PV by more than 70%.[49]

[49] The 6-15% range reflects the costs of capital being observed for utility-scale solar PV projects in emerging markets and developing economies.

Box 3.3 Sizing renewable electricity for electrolytic hydrogen production

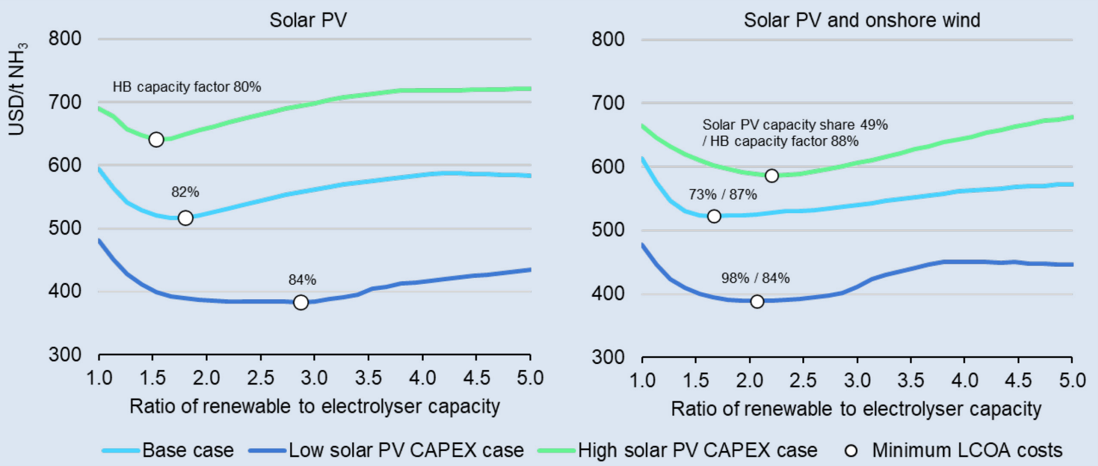
Many electrolyser projects for hydrogen production include dedicated renewable electricity plants, often solar PV, onshore or offshore wind. For example, the NEOM project under construction in Saudi Arabia plans to use 4.6 GW of solar PV and onshore wind capacity to provide electricity for a more than 2 GW electrolyser, with the hydrogen being used in a Haber-Bosch synthesis process for ammonia production. The investments for renewable electricity generation often account for the majority of the overall investments of a hydrogen project in which an electrolyser is combined with a dedicated renewable electricity supply.

The design of such a project, in particular in terms of the installed electrolyser capacity and the renewable generation capacity, depends on various factors. If the produced hydrogen is used in further synthesis processes, such as the Haber-Bosch process for ammonia synthesis, a relatively stable hydrogen supply and high full load hours for the synthesis process are desirable. This can be achieved by a larger capacity ratio of renewable generation to the electrolyser (and the design also depends on the overall economics in combination with other measures, such as adding hydrogen storage or also using grid electricity for some of the time, if available). In such a configuration, part of the renewable electricity, if not stored in batteries or used otherwise, may be curtailed, but overall, such a design can help to increase the overall full load hours of the electrolyser and the synthesis process. Similarly, relatively low CAPEX costs for renewable generation capacity in comparison to the electrolyser CAPEX can favour a larger capacity ratio of renewable capacity to electrolyser. Relatively low CAPEX for the electrolyser and the synthesis process (or relatively high renewable CAPEX) may favour a configuration with a lower capacity ratio of renewable generation to the electrolyser, i.e. overall, the benefits of lower investments in renewable capacity offset the lower utilisation of the electrolyser (and a potential downstream synthesis process).

These relationships are illustrated for the case of production of ammonia, using a Haber-Bosch synthesis process, an electrolyser and solar PV for the electricity supply as well as battery storage and hydrogen storage tanks. In the base case with a solar PV CAPEX of USD 600/kW and an electrolyser CAPEX of USD 615/kW, a solar PV to electrolyser capacity ratio of 1.8 results in the lowest ammonia production costs. Halving the solar PV CAPEX leads to an optimal design with a capacity ratio of 2.9, while the capacity factor of the Haber-Bosch synthesis process increases from 82% to 84%. With lower solar PV costs, the cost curve also becomes flatter, i.e. with lower solar PV costs, the impact of the electricity costs on the ammonia production costs becomes less pronounced. If the solar PV CAPEX increases to USD 900/kW, the optimal solar PV to electrolyser capacity ratio decreases to 1.5 and the capacity factor of the Haber-Bosch synthesis to 80%.

Combining solar PV and onshore wind can be another way to increase the capacity factor of the electrolyser and the Haber-Bosch synthesis. Including onshore wind in the base case increases the capacity factor of the Haber-Bosch synthesis to 87% compared to 82% when using only solar PV as the renewable electricity option. The ammonia production costs decline by 4%. In the case that both solar PV and onshore wind are available, higher solar PV CAPEX does not necessarily lead to a lower renewable to electrolyser capacity ratio. At the location considered here, renewable generation shifts with higher solar PV CAPEX to onshore wind, but also to a replacement of grid electricity by onshore wind, so that the overall renewable to electrolyser capacity with higher solar PV CAPEX is actually larger than in the base case for solar PV CAPEX.

Ammonia production cost from solar PV and from solar PV and onshore wind hybrid systems



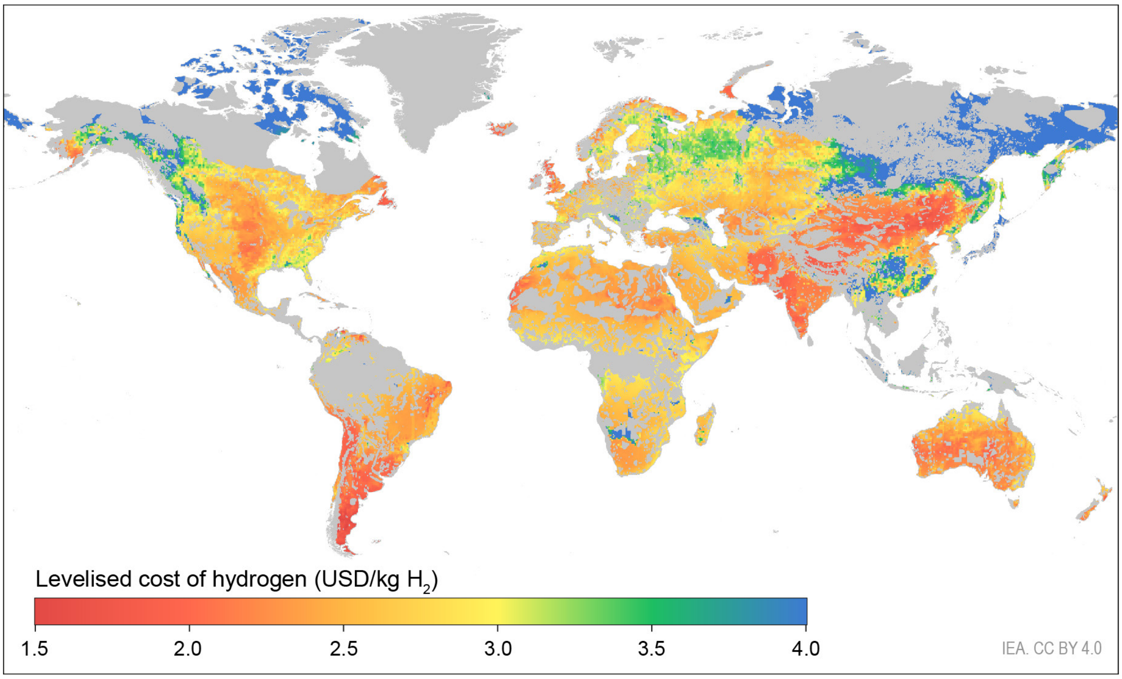
Notes: LCOA = levelised cost of ammonia production; CAPEX = capital expenditure.

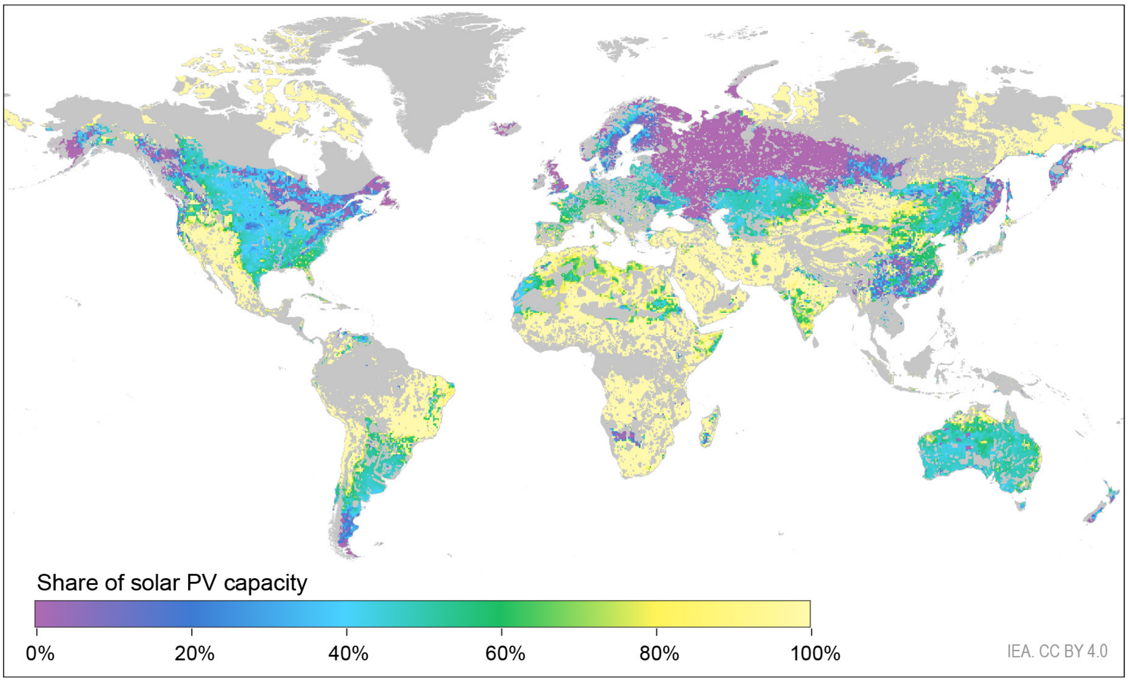
The analysis is based on the following assumptions: solar PV CAPEX is USD 600/kW in the base case, USD 300/kW in the low solar PV CAPEX case and USD 900/kW in the high solar PV CAPEX case, reflecting the regional CAPEX range for utility-scale solar PV in the Net Zero Emissions by 2050 Scenario in 2030. CAPEX for onshore wind is kept constant at USD 1 270/kW. CAPEX for electrolysers is USD 615/kW, for battery storage USD 180/kWh and for hydrogen storage tanks USD 350/kg H_2. Firm grid electricity is available at costs of USD 100/MWh in addition to renewable electricity available for the electricity needs of the Haber-Bosch synthesis. Location with annual average capacity factor of 26% for solar PV and 40% for onshore wind. Further techno-economic assumptions will be made available in a separate forthcoming Annex.

Analysis was done by determining the cost optimal configuration for given technology costs, hourly solar PV and onshore wind capacity factors and given renewable to electrolyser capacity ratios. The left figure only considers solar PV as a renewable electricity source, while the right figure considers hybrid systems of solar PV and onshore wind.

Various regions around the world have excellent renewable resource conditions to produce hydrogen from renewable electricity at low costs (Figure 3.13).

Figure 3.13 Hydrogen production costs and share of solar PV from hybrid solar PV and onshore wind systems, 2030





Notes: LCOH = levelised costs of hydrogen production. For each location, production costs are determined by optimising the mix of solar PV, onshore wind, electrolyser, battery and hydrogen storage capacities, resulting in the lowest costs. Onshore wind has been excluded in permafrost regions due to more challenging requirements for the foundation of wind turbines, so that solar PV is the sole hydrogen production option, which explains the high solar shares in these regions. Based on an electrolyser CAPEX of USD 615/kW, regional solar PV and onshore wind CAPEX reflecting 2030 values in the Net Zero Emissions by 2050 Scenario and a weighted average cost of capital of 6%.

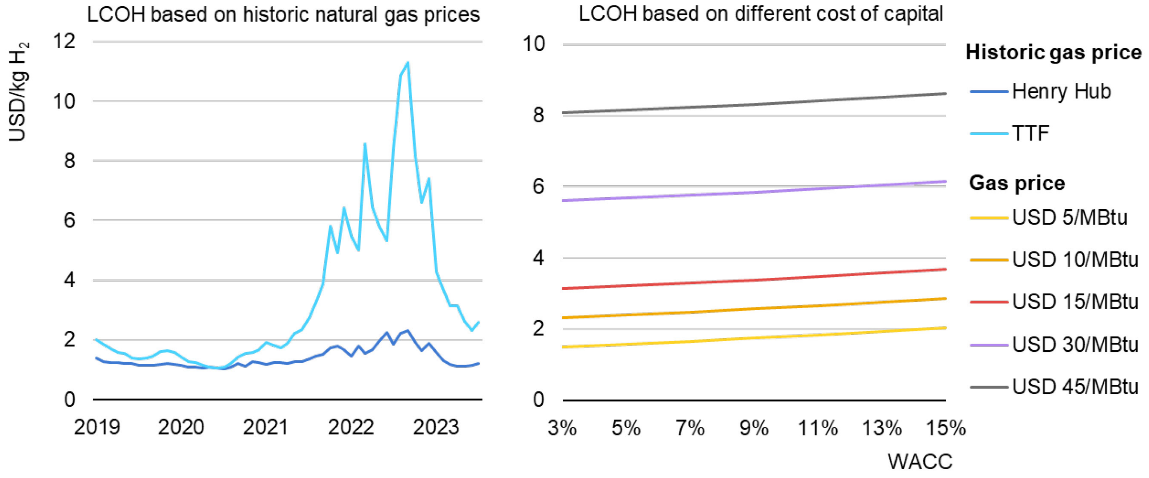
Source: Analysis by IEK-3, Research Centre Jülich using the ETHOS model suite.

Various regions around the world have excellent renewable resources for low-cost hydrogen production. Costs could fall below USD 1.5 kg H_2 by 2030.

If these low-cost renewable resources exceed the amounts needed domestically, these resources can be an opportunity for countries to export the renewable electricity in the form of hydrogen or products using hydrogen (e.g. steel, ammonia) to regions that have demand but limited potential for low-emission hydrogen production. The overall costs and thus the competitiveness of these exports will not only depend on the hydrogen production costs, but also the transport costs, as illustrated in Box 4.1 in Chapter 4 Trade and infrastructure.

Using a single renewable resource, such as solar PV or offshore wind, can be the cheapest option for renewable hydrogen production in many locations. A hybrid approach that combines solar PV and onshore wind, for example, can lead to higher CAPEX costs, but results in higher full load hours of the electrolyser, such that this combination can result in the lowest production costs at some locations. his holds true even for some excellent solar PV locations in Northern Africa and Australia as long as wind capacity factors are sufficiently high. Combining solar PV with wind reduces the hydrogen production costs despite higher costs for wind electricity. The higher full load hours realised by this hybrid approach can also benefit the economics and operation of subsequent synthesis processes, such as ammonia production. Other options to increase the full load hours of the electrolyser also exist, such as oversizing the renewable generation capacity, as discussed in Box 3.3.

Figure 3.14 Levelised cost of hydrogen production with carbon capture, based on different natural gas prices and on different costs of capital in the Net Zero Emissions by 2050 Scenario, 2030



Notes: LCOH = levelised cost of hydrogen; MBtu = million British thermal units; TTF = Title Transfer Facility; WACC= weighted average cost of capital. Weekly average historic natural gas closing prices for TTF in Europe and Henry Hub in the United States have been used to calculate the hydrogen production cost from natural gas with carbon capture, utilisation and storage (CCUS) in the left-hand side figure. The capture rate is 93%.

Sources: Based on data from McKinsey & Company and the Hydrogen Council; NREL (2022); IEA GHG (2017).

Natural gas prices are the key cost factor for hydrogen production from natural gas with CCUS. Doubling the weighted average cost of capital from 5% to 11% increases the production costs by around 3% to 17%.

The cost of producing hydrogen from natural gas with CCUS is strongly influenced by the natural gas price and its fluctuations (Figure 3.14). Gas price levels of up to USD 70/Mbtu, as seen in Europe in 2022 following the Russian invasion of Ukraine, mean that hydrogen from natural gas becomes a very expensive option. Since then, natural gas prices have fallen in Europe to an average of USD 14/MBtu over the first months of 2023. At this gas price, hydrogen production from natural gas with CCUS would cost around USD 3/kg H_2. In the United States, average gas prices in the first half of 2023 have been much lower, at USD 2.7/MBtu, corresponding to a cost of hydrogen production with CCUS of USD 1.2/kg H_2. For hydrogen production from natural gas with CCUS, reaching production costs of USD 1/kg H_2 requires the gas price to be below USD 1/MBtu.

The impact of the WACC on the cost of hydrogen production from natural gas with CCUS is much lower than for renewable hydrogen produced with electrolysis, given that the cost of production from electrolysis using renewable electricity is almost entirely based on CAPEX, whereas for production from natural gas the CAPEX share is 5-30%. A 2%-point WACC increase from 3% to 5% results in a cost increase of around USD 0.1/kg H_2. A doubling of the WACC from 5% to 11% results in a cost increase of 3-17%, depending on the gas price and the impact of WACC changes being larger at lower gas prices.

Emissions intensity of hydrogen production routes

The emissions associated with hydrogen production can vary significantly between production routes, depending on the fuel, technology and the rate at which carbon capture and storage (CCS) is applied. In addition to direct emissions occurring in the production of hydrogen, indirect emissions from the production, conversion and transport of the required input fuels, such as natural gas or electricity, can affect the overall emissions associated with hydrogen production. Based on the methodology developed by the International Partnership on Hydrogen and Fuel Cells in the Economy (IPHE) and using IEA data for the production technologies and upstream and midstream emissions, Figure 3.15 provides an overview of the emissions intensities of different production routes.[50]

The direct emissions of hydrogen production from natural gas without CCS using SMR are around 9 kg CO_2 equivalent per kg of hydrogen (CO_2-eq/kg H_2). Further emissions occur in the production, processing and transport of natural gas, either in the form of methane emissions from venting or leakages, or as CO_2 emissions from flaring methane at gas fields or linked to the energy being used to produce and transport natural gas (e.g. emissions linked to the electricity for compressing natural gas). The global upstream and midstream emissions from gas production today range from 4.5 kg CO_2 equivalent per gigajoule of produced natural gas

[50] More details can be found in the IEA report Towards hydrogen definitions based on their emissions intensity.

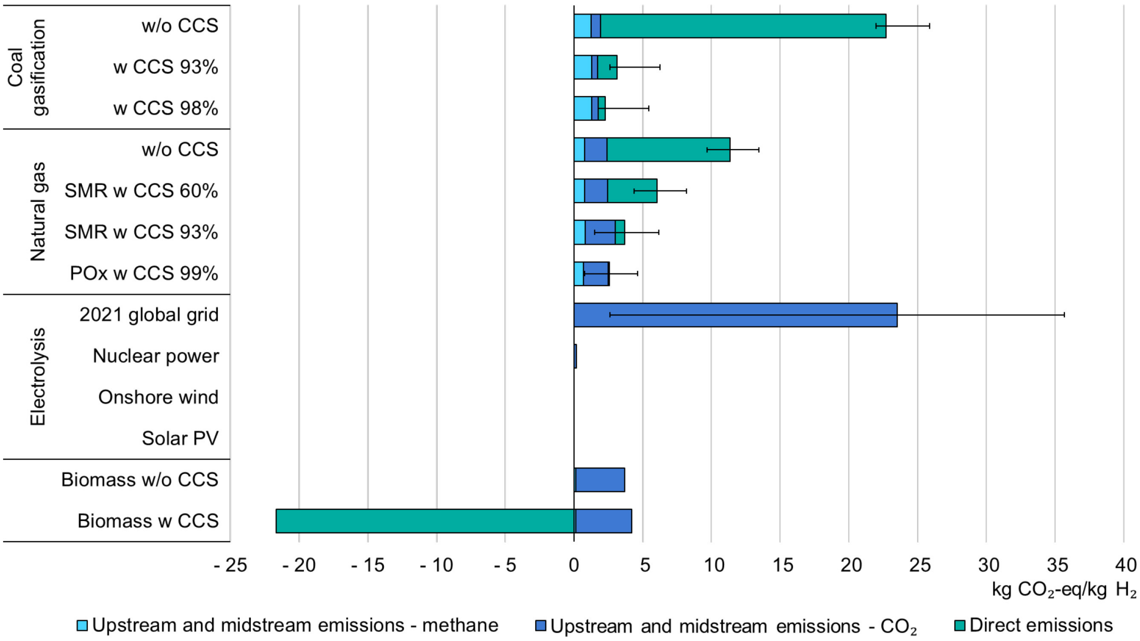
(kg CO_2-eq/GJ_{NG}) to 28 kg CO_2-eq/GJ_{NG}, with a median value of 15 kg CO_2-eq/GJ_{NG}. Using this median value, upstream and midstream operations result in additional emissions of 2.4 kg CO_2-eq/kg H_2, and total emissions of 10-13 kg CO_2-eq/kg H_2 for the SMR production route from natural gas without CCS. Applying CCS to the various direct CO_2 sources at the SMR hydrogen plant can reduce the direct emissions to 0.7 kg CO_2-eq/kg H_2 (capture rate 93%) and the total emissions to 1.5-6.2 kg CO_2-eq/kg H_2 when including the upper and lower end of global upstream and midstream emissions for natural gas supply today.

Hydrogen production from coal gasification without CCS results in total emissions of 22-26 kg CO_2-eq/kg H_2, depending on the upstream and midstream emissions for coal mining, processing and transport, which range between 6-23 kg CO_2-eq/GJ_{coal} with a median of 8 kg CO_2-eq/GJ_{coal}. More than 80% of the emissions intensity of hydrogen production from coal is from direct emissions at the production plant and less than 20% is linked to coal mining, processing and transport. Applying CCS with a total capture rate of 93% reduces the emissions intensity of the coal pathway to 2.6-6.3 kg CO_2-eq/kg H_2, a range similar to that of natural gas SMR with CCS.

The emissions from water electrolysis are determined by the emissions of electricity generation and transport. Using the current average global CO_2 intensity of 460 g CO_2-eq/kWh results in an emissions intensity for hydrogen of 24 kg CO_2-eq/kg H_2, similar to the emissions for hydrogen from unabated coal, but the emissions intensity can be as low as 0.5 kg CO_2-eq/kg H_2 in a country such as Sweden, which has one of the lowest emission factors for grid electricity production in the world today (10 g CO_2-eq/kWh).

Nuclear electricity can be another source for hydrogen production. Although the direct emissions of a nuclear power plant are zero, the nuclear fuel cycle of uranium mining, conversion, enrichment and fuel fabrication results in emissions of 2.4-6.8 g CO_2-eq/kWh. Taking those emissions into account, the emissions intensity of hydrogen production from nuclear electricity is in the range of 0.1-0.3 kg CO_2-eq/kg H_2. Following the IPHE methodology and the global assumption for renewable electricity regardless of its application, renewable electricity from wind, solar PV, hydropower and geothermal energy has zero upstream and direct emissions, i.e. the emissions associated with the manufacturing of solar PV systems or wind turbines are not taken into account. As a result, water electrolysers using these forms of renewable electricity also have zero emissions.

Figure 3.15 Comparison of the emissions intensity of different hydrogen production routes, 2021



Notes: CCS = carbon capture and storage; POx = partial oxidation; SMR = steam methane reforming.

Upstream and midstream emissions include CO_2 and methane emissions occurring during the extraction, processing, and supply of fuels (coal, natural gas) or production, processing, and transport of biomass. Error bars for natural gas and coal represent the impact of the observed range of upstream and midstream emissions today on emissions intensities. For natural gas, the lower bound corresponds to best available technology today (4.5 kg CO_2-eq/GJ), and the upper bound to the 95% percentile of the world range (28 kg CO_2-eq/GJ). For coal, the lower bound corresponds to the 5% percentile (6 kg CO_2-eq/GJ) and the upper bound to the 95% percentile (23 kg CO_2-eq/GJ) of global upstream and midstream emissions of coal supply. The 2021 world grid average is based on a generation-weighted global average of the grid electricity intensity, with the error bars representing the 10% percentile (50 g CO_2-eq/kWh) and 90% percentile (700 g CO_2-eq/kWh) across countries. The grid electricity intensities include direct CO_2, methane (CH_4) and nitrous oxide (N_2O) emissions at the power plants, but not upstream and midstream emissions for the fuels used in the power plants.

Electrolysis refers to low-temperature water electrolysis with an assumed overall electricity demand of 50 kWh/kg H_2, including compression to 30 bar.

Hydrogen production from natural gas via SMR is based on 44.5 kWh/kg H_2 for natural gas in the case of no CO_2 capture, on 45.0 kWh/kg H_2 for natural gas in the case of 60% capture rate, and on 49 kWh/kg H_2 for natural gas and 0.8 kWh/kg H_2 for electricity in the case of a 93% capture rate. Hydrogen production from natural gas via POx is based on demands of 41 kWh/kg H_2 for natural gas and 0.6 kWh/kg H_2 for electricity in the case of a 99% capture rate.

Hydrogen production from coal is based on gasification, with demands for coal of 57 kWh/kg H_2 and for electricity of 0.7 kWh/kg H_2 in the case of no CO_2 capture, demands for coal of 59 kWh/kg H_2 for a CO_2 capture rate of 93% and demands for coal of 60 kWh/kg H_2 for a CO_2 capture rate of 98%.

Emissions intensity can vary significantly between different production routes. High capture rates and minimising upstream emissions will be critical for fossil routes with CCS, while for electrolytic hydrogen a low emissions intensity of the electricity is important.

The emissions intensity of hydrogen production provides a transparent indicator to be used by governments in regulations, by certification bodies or by market participants in trade transactions (see Chapter 6 Policies). Nevertheless, stakeholders such as investors, some final consumers of hydrogen-based products and the general public may also find value in a simpler presentation of the emission intensities, using intensity levels as presented in Box 3.4.

Box 3.4 Using emissions intensity levels for non-expert users

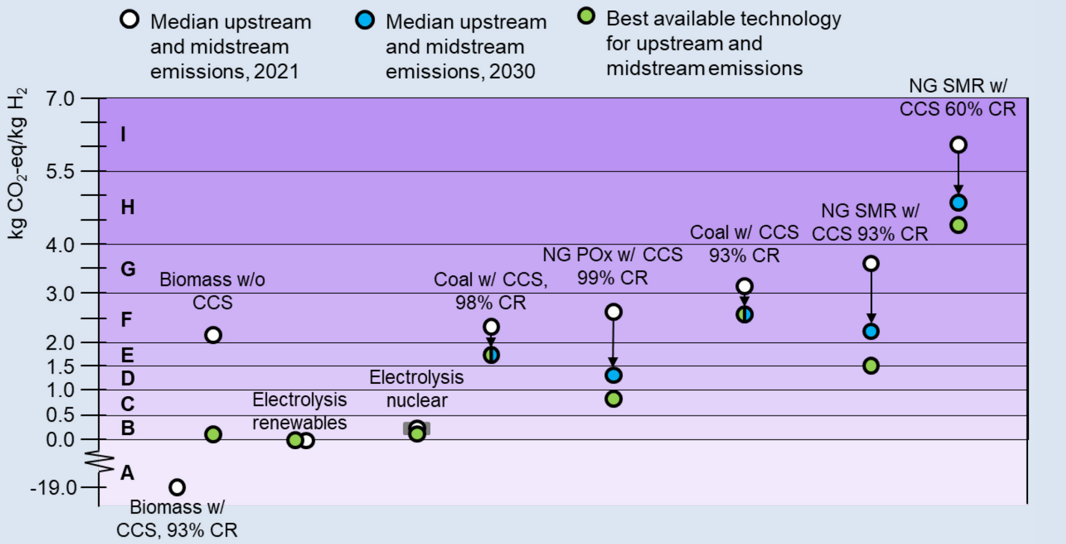
The precise emissions intensity of hydrogen production is likely to be a key indicator for governments, regulatory authorities, certification bodies and market participants. For other stakeholders, it may be less intuitive. Investors, financial institutions, final consumers of hydrogen-based products and the general public may struggle to interpret technical details or to quickly grasp the relative scale of emissions. The importance of communicating in simple terms can already be seen in the extent to which the terms “blue” and “green” hydrogen are being used by experts and non-experts alike.

When shifting from describing hydrogen using colours to using a more accurate measure of emissions intensity it is not necessary to entirely do away with the simplicity of distinguishing between a small set of hydrogen archetypes. A system that groups the emissions intensity into a smaller set of distinct levels could provide a valuable complement, allowing for easily accessible communication of the emissions implications.

One possible approach could be to use a set of distinct, technology-neutral levels, ranging from emissions intensities below zero (level “A”) to an upper value, as illustrated in the figure below. The proposed levels reflect known hydrogen production routes that can achieve lower emissions than unabated fossil-based routes, while also considering potential for future improvement in the production technologies and fuel supply chains, such as reductions in upstream and midstream methane emissions in natural gas supply. Systems could also be designed to include unabated fossil-based production routes or more granularity at lower levels, to better reflect existing regulations set up by countries.

If hydrogen use becomes widespread across the energy sector and relevant to the wider public then some stakeholders, such as the investment community and general public, may appreciate the simplicity of quoting the aggregated “level” of emissions intensity. For example, hydrogen on sale at refuelling stations could be presented by its level to inform consumers of their environmental choices in a manner equivalent to energy efficiency labelling of appliances and buildings.

Example of a potential quantitative system for emissions intensity levels of hydrogen production



Notes: CCS = carbon capture and storage; CR= capture rate; NG = natural gas; POx = partial oxidation; SMR = steam methane reformer.

Source: IEA (2023), Towards hydrogen definitions based on their emissions intensity.

Emerging production routes

Other low-emission hydrogen production routes have gained some attention lately, particularly biomass-based routes, natural hydrogen and methane decomposition.

Hydrogen can be produced from bioenergy (either from biomass or waste) using different technologies. The use of bioenergy has the potential to produce low-emission hydrogen with very low emissions intensity, even reaching negative emissions intensity when coupled with CCUS (see Figure 3.15Figure 3.1). However, the emissions intensity of bioenergy-based routes will strongly depend on upstream emissions of the biomass supply chain. In the case of using waste, its composition plays an important role. Waste tends to be a mix of materials that can have both biogenic (e.g. food waste) or fossil origin (e.g. plastics) and can have a very heterogenic composition, which in the case of municipal solid waste can vary between different regions depending on cultural habits and even in the same region between different periods of the year. The biogenic waste fraction has the potential for producing low-emission hydrogen (depending on upstream supply chain emissions), whereas the plastic waste fraction cannot not result in low-emission hydrogen unless the production process includes CO_2 capture and storage.

Biomass gasification is the most developed technology. It produces synthesis gas by breakdown of the organic matter of solid biomass at high temperatures and the presence of an oxidant (which can be steam, oxygen or carbon dioxide). There are already demonstration projects operating in Japan and France, both using wastewater sludge as a feedstock.[51] In addition, some pre-commercial scale plants are expected to be operative soon. In February 2023, SGH2 reached FID on a plant to produce 4.5 kt H_2/y using its plasma-enhanced gasification technology in Lancaster (United States). Mote (a US-based company) is developing two biomass gasification projects, with one coupling CCUS to the process. Yosemite Clean Energy, in the United States, and OMNI, in Canada, have also projects at advanced stages of development.

US companies have been leading the development of biomass gasification, but India has also shown a strong interest in biomass-based technologies. Reliance successfully tested in August 2023 the gasification of torrefied biomass[52] for hydrogen production and plans to develop a pre-commercial demonstrator to produce 18 kt H_2/y using catalytic gasification. The Indian Oil Corporation and the Indian Institute of Science are developing a small plant (88 t H_2/yr) to demonstrate biomass gasification (using steam and oxygen as oxidants) for hydrogen production, aiming to start operation in December 2023. The Indian government is also promoting biomass-based routes and has earmarked funds to specifically support 40 kt H_2/y of capacity production from biomass as part of its incentive scheme for “green” hydrogen production.[53]

Biomass pyrolysis is another technology alternative, similar to gasification, although it does not involve the use of any oxidant. Pyrolysis produces a combination of liquid organic products, gases and a carbonaceous residue, with the liquid fraction being the one with higher yields. For this reason, pyrolysis seems to be better fit for liquid biofuels production and has attracted less interest than gasification for hydrogen production. However, Kore Infrastructure has a pilot plant operating in Los Angeles (United States) since 2021.

Biomethane can be used in reformers to produce hydrogen in the same way as natural gas. More than 70 facilities are certified in the California Low Carbon Fuel

[51] These demonstration projects aim to use biomass gasification for dedicated hydrogen production. Other projects have demonstrated the use of biomass gasification for other purposes, such as combined heat and power generation.
[52] Argus direct (2023), India’s Reliance eyes green H2 production from biomass.
[53] See Explanatory notes annex for the use of the terms “green”, “blue” and “clean” hydrogen in this report.

Standard programme for blending biomethane or landfill gas in natural gas reformers to decrease the carbon intensity of their production facilities.

Methane decomposition has progressed significantly in terms of technology maturity over the past years, particularly plasma decomposition, in which the energy demand of the process is supplied by electricity, which ignites the plasma (an ionised gas). The plasma reaches temperatures in the range of 1 000-2 000 °C and splits methane into its elements. Plasma decomposition can also occur at low temperature, but the technology is at a much earlier stage of development. In 2021, Monolith Materials, a technology developer based in the United States, put into operation the first commercial-scale facility to produce hydrogen and carbon in solid form (carbon black) using high-temperature plasma decomposition. The next phase of this project, called Olive Creek 2, will commercially generate hydrogen to produce ammonia (200 kt H_2/year) from 2025. There is no other commercial-scale plant currently operating, but companies such as Graforce (Germany) and Spark (France) are also developing this technology.

Catalytic decomposition is a less developed technology, in which methane is decomposed at high temperatures (though lower than in plasma pyrolysis) in the presence of a catalyst. Hazer, an Australia-based technology developer, is building a commercial demonstration plant (100 t H_2/yr), with start-up expected for late 2023. The company has also announced the development of commercial projects in Canada, France and Japan (2 500 – 10 000 t H_2/yr). At a smaller scale, Hycamite, a Finnish company, has secured permits and raised funds to start construction of a demonstration facility. C-Zero, a company based in the United States, has raised USD 34 million in funding to build a 146 t H_2/yr facility.

A third technology, and the least developed, is thermal decomposition. Ekona, a Canadian developer, is working on a demonstration project with the aim of becoming operational in 2023. Aurora, another Canadian company, is working on an innovative process to apply microwave heating to thermal decomposition of methane.

The Earth continuously produces **natural hydrogen** underground through a series of chemical reactions (oxidation of ferrous iron minerals, water radiolysis, organic matter maturation and outgassing from the Earth's mantle). A growing number of discoveries of underground natural accumulations of hydrogen have triggered interest in natural hydrogen as a complement to other low-emission hydrogen production technologies. Natural hydrogen presents several advantages: it is an energy source and not an energy vector, thus eliminating the need for fossil fuels and electricity in its production (resulting in reduced emissions and avoiding energy transformation losses). Additionally, production is not subject to intermittency (as in renewable-based production), production sites have a limited land footprint and there is no need for purified water or CO_2 storage.

However, extracting natural hydrogen requires compression and purification systems since natural hydrogen accumulations contain different impurities (such as nitrogen, methane, CO_2, helium and argon) and the hydrogen content can vary widely (2.4-100% in volume) depending on the location, the type of accumulation and the depth. These factors can affect the life-cycle emissions of natural hydrogen production. Initial studies suggest that these can be low (<1 kg CO_2/kg H_2) but vary over the lifetime of the well (due to reduced well productivity), and can be highly impacted by impurities (particularly methane).

Initial estimates suggest that the Earth's hydrogen potential exceeds current demand and could even be capable of meeting the growing requirements of decarbonisation scenarios. However, the potential exploitation of natural hydrogen presents challenges and remains highly uncertain. Detailed geological surveys tracking natural hydrogen accumulations are not readily available, impeding a comprehensive understanding of its formation, migration and commercial exploitability. There is a possibility that the resource is too scattered to be captured in a way that is economically viable. While proponents claim lower production costs compared to other methods (in the range of USD 0.5-1/kg H_2), such as natural gas, the exact cost implications remain to be seen.

The number of companies engaged in natural hydrogen exploration has significantly increased, with 40 active companies as of mid-2023, compared to only 3 companies in 2020. However, the lack of regulatory frameworks in some countries has slowed down project development, although progress has been made in others, with licensing already happening in Australia, France, Mali, Spain and the United States (Table 3.1). So far, development has been spearheaded by small wildcatters, but some major energy companies have started to show interest in the technology, including Shell, BP and Chevron joining a consortium led by the US Geological Survey and Colorado School of Mines, focusing on studying natural hydrogen.

Table 3.1 Selected developments for natural hydrogen production

Country	Location	Developers	Status
Australia	Yorke peninsula	Gold Hydrogen	Drilling permit granted. Exploration from October 2023.
Australia	Eyre Peninsula	H2EX	Permit granted.
Australia	Amadeus Basin	Santos	Drilling wells to evaluate resource.
France	Lorraine basin	La Française d'Énergie	Application for exclusive mining exploration permit submitted.
Mali	Bourakebougou	Hydroma	Operational since 2012, demonstration.
Spain	Pyrenees	Helios Aragon	Drilling permit granted. Exploration from 2024.
United States	Arizona	Desert Mountain Energy	Application for exploration permit submitted*.

Country	Location	Developers	Status
United States	Kansas	Natural Hydrogen Energy	Exploratory drilling completed in 2019.
United States	Nebraska	HyTerra	Drilling completed. Potential production from 2023.

* The company is focusing on helium production with a secondary focus on developing hydrogen assets located within their helium fields.

Production of hydrogen-based fuels and feedstocks

Hydrogen-based fuels and feedstocks, including ammonia, methanol and synthetic hydrocarbons (synthetic methane and Fischer-Tropsch products such as diesel and kerosene), are easier to store and transport than pure hydrogen, and can often make use of existing infrastructure such as natural gas pipelines and end-use technology such as aeroplanes. Despite the advantages with regards to storage and transport, producing hydrogen-based fuels entails additional costs, energy and feedstocks to convert hydrogen into these fuels.

During 2022, projects for a cumulated potential low-emission hydrogen production equivalent of 0.02 Mt have begun operation, bringing the total number of projects to 80 and the global total production to 0.3 Mt H_2, or around half of the total low-emission production in 2022. Most of this increase comes from hydrogen to produce ammonia for use as a fuel and feedstock, which reached 0.17 Mt H_2 in 2022. Synthetic methane continues to be the second largest share of hydrogen-based fuel projects on a hydrogen-equivalent basis, although little to no additional production began in 2022.

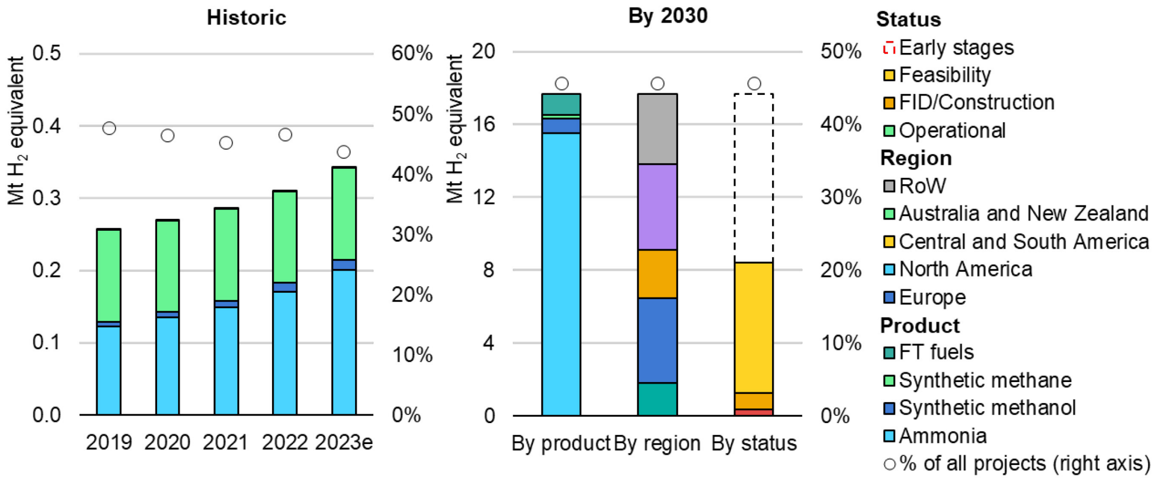
Announced projects are set to rapidly multiply the 2022 production capacity, with 17 Mt of H_2 equivalent slated to begin operation by 2030[54] (Figure 3.16) from a total of 325 projects, over twice the number of projects that were identified in the GHR 2022. These trends continue to 2030, as ammonia captures around 80% of announced production. The high share of ammonia could be a sign of the fertiliser industry's readiness to directly absorb the low-emission alternative as a drop-in feedstock for its existing processes. Ammonia does not require carbon, simplifying supply chains and making it an attractive early mover among hydrogen-based fuels. Additionally, ammonia can be used as a long-distance carrier for hydrogen, taking advantage of existing know-how on transporting ammonia around the world established by the fertiliser industry. However, nitrogen oxides (NO_x) and nitrous oxide (N_2O) emissions must be minimised when ammonia is combusted as a fuel

[54] This could decrease to almost 10 Mt if projects at a very early stage of development (e.g. only a co-operation agreement among stakeholders has been announced) are excluded.

(see section on Electricity generation in Chapter 2 Hydrogen use for more information).

Other hydrogen-based fuels make significant inroads to 2030 in the announced projects compared to 2022, including Fischer-Tropsch (FT) fuels and synthetic methanol, driven by demand from the aviation and shipping sector, respectively.

Figure 3.16 Global hydrogen-based fuel production by fuel, region and status, historical and based on announced projects



Notes: FID = final investment decision; FT = Fischer-Tropsch; RoW = rest of world.
Source: IEA Hydrogen Projects, (Database, October 2023 release).

Hydrogen-based fuels production, in particular for ammonia, could grow rapidly by 2030 based on announced projects, accounting for almost 50% of hydrogen production from all projects.

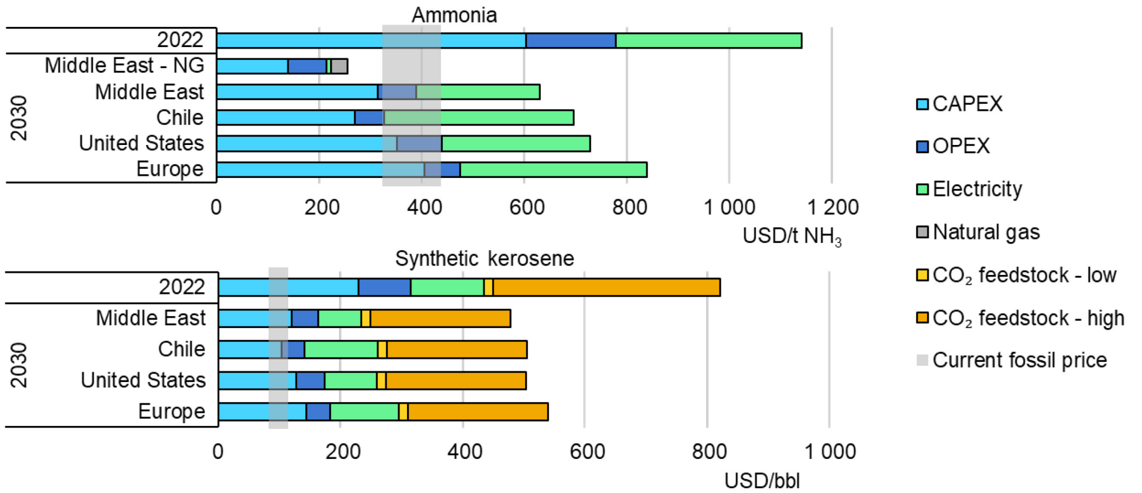
The announced hydrogen-based fuels projects reflect a broad geographical diversity, with significant capacity planned for all major regions in the world. Australia and North America claim the largest shares of announced projects, each with 4.7 Mt H_2 equivalent[55] in 2030, coming from around 75 projects combined. North America claims the largest share of the announced projects, with around 30. Central and South America and Europe are the next largest contenders, accounting by 2030 for around 2.6 Mt and 1.8 Mt H_2 equivalent.[56]

[55] This could decrease to 0.9 Mt for Australia and 2.8 Mt for North America, if projects at a very early stage of development, e.g. only a co-operation agreement among stakeholders has been announced, are excluded.
[56] This could decrease to 1.7 Mt and 1.2 Mt respectively if projects at a very early stage of development, e.g. only a co-operation agreement among stakeholders has been announced, are excluded.

Overall, only 5% of hydrogen-based fuels projects (in terms of Mt H_2 equivalent production) have reached FID or are under construction, with the most nascent projects focused on synthetic hydrocarbons.

Converting hydrogen into other fuels and feedstocks adds to the cost of production. For ammonia from electrolytic hydrogen, the investment cost today represents more than 50% of the production costs, mainly due to the electrolyser CAPEX (Figure 3.17). As electrolysis costs fall, so too do overall production costs, and electricity feedstock could become the main cost component with a 40-50% share, depending on the region. For ammonia produced from natural gas with CCUS, the fuel cost share can range from 35% for a gas price of USD 5/MBtu, to 75% at a gas price of USD 35/Mbtu.

Figure 3.17 Levelised costs of ammonia and synthetic kerosene for electricity-based pathways in 2022 and in the Net Zero Emissions by 2050 Scenario in 2030



Notes: CAPEX = capital expenditure; OPEX= operational expenditure; NH_3 = ammonia; NG = Natural gas-based production, with carbon capture. "Middle East - NG" refers to the integrated steam methane reformer with carbon capture for the production of ammonia. Values for 2022 refer to electricity production from solar PV in Middle East; 2030 values are based on the Net Zero Emissions by 2050 Scenario, with the best renewable-based production routes in each region. Hydrogen storage cost to reach a minimum of 80% capacity factor of the synthesis processes is included. Current fossil price refers to the prices from May-August 2023 for the production of ammonia from natural gas without CCUS and for fossil kerosene.

Sources: Based on data from McKinsey & Company and the Hydrogen Council; NREL (2022); IEA GHG (2017).

Hydrogen-based fuels from electrolytic hydrogen are today more expensive than from unabated fossil fuels. By 2030, costs could fall by around 40% due to reductions in the cost of renewable electricity and electrolysers.

For FT liquids such as synthetic kerosene from electrolytic hydrogen, production costs vary greatly based on the source of CO_2. If, for example, biogenic CO_2 from ethanol production is used at a cost of USD 30/t CO_2, then electrolysis and conversion losses account for three-quarters of production costs, while the synthesis contributes one-fifth. Biogenic CO_2 will be limited by the bioenergy availability and linked to the future deployment of bioenergy with carbon capture and storage (BECCS). Direct air capture (DAC)-sourced CO_2 does not face the same supply constraints but comes at a much higher cost. DAC technology is still at an early development stage, with only a few plants in operation worldwide. Current DAC credits on the market are around USD 600-1 000/t CO_2, but with further deployment and technology improvements, costs could fall to USD 200-700/t CO_2 by 2030. As a consequence, the production costs of synthetic kerosene from renewable hydrogen, which today are in the range of USD 450-820 per barrel (bbl), are much higher than conventional kerosene (at almost USD 100/bbl), but could fall to USD 200-550/bbl by 2030.

Chapter 4. Trade and infrastructure

Hydrogen trade could become an important cornerstone for the development of hydrogen markets. Trade would allow countries with limited domestic resources for low-emission hydrogen production – but with a need for hydrogen to decarbonise their energy systems – to import hydrogen from regions with ample low-cost resources for low-emission hydrogen production that exceed domestic needs. Exporting countries could therefore benefit economically from exporting hydrogen or products produced from hydrogen, while for importing countries hydrogen trade can be an opportunity to improve energy security by reducing fossil energy imports and diversifying the supply countries for hydrogen imports.

Infrastructure to transport and store hydrogen is an important enabler for hydrogen trade. However, since hydrogen has a relatively low volumetric energy density and low liquefaction temperature, transporting and storing hydrogen is technically more challenging than the handling of fossil fuels today. This includes the need to liquefy or compress hydrogen, or to convert hydrogen into carriers such as ammonia or liquid organic hydrogen carrier (LOHC). Developing trade in merchant hydrogen would entail complexities requiring careful consideration of the cost, benefits and potential trade-offs in exporting and importing countries alike.

Status and outlook of hydrogen trade

International trade in hydrogen is today at a very nascent stage, not least when compared to the needs for hydrogen trade in the Net Zero Emissions by 2050 Scenario (NZE Scenario), in which more than 20% of merchant demand for hydrogen and hydrogen-based fuels is met through international trade by 2030. Today, hydrogen trade flows are limited to a few existing hydrogen pipelines connecting industrial areas in Belgium, France and the Netherlands, and to a few pilot projects to demonstrate hydrogen trade by ship. The only exceptions are ammonia and methanol, which are already globally traded as feedstocks for the chemical industry. Around 10% of global ammonia demand was met through international trade in 2021, and for methanol the trade share was 20%. However, existing trade is linked to use in the chemical industry, and international trade in ammonia and methanol for fuel purposes has only been tested in some first pilot projects.

Recent trade projects

Various technology options can be used to trade hydrogen internationally. For seaborne trade, the shipment of hydrogen in the form of liquefied hydrogen and

LOHC have been demonstrated in first projects, while experience in shipping ammonia exists in the fertiliser industry. In 2020, the first international trade of 102 t H_2 took place from Brunei to Japan, using methylcyclohexane as an LOHC. For liquefied hydrogen, a first cargo of 75 t H_2 was delivered in 2022 from Australia to Japan as part of the Hydrogen Energy Supply Chain (HESC) project, with plans to scale up the trade volumes to 225 kt per year in the 2030s. Kawasaki Heavy Industry is preparing a feasibility study for another project that plans to ship 36.5 kt H_2 per year from the port of Townsville, Australia, to Japan. In 2020, for the first time, ammonia for use as a fuel was shipped from Saudi Arabia to Japan. More shipments of ammonia from Saudi Arabia and the United Arab Emirates occurred in 2022 and 2023 or are planned for later this year (Table 4.1).

Table 4.1 Planned and completed trade pilot projects for low-emission hydrogen and hydrogen-based fuels, 2020-2023

Trade pilot project	Hydrogen carrier	Year	Quantity traded
Saudi Arabia to Japan	Ammonia	2020	40 t NH_3
Brunei to Japan	LOHC	2020	102 t H_2
Australia to Japan*	LH_2	2022	75 t H_2
Saudi Arabia to Korea	Ammonia	2022	25 000 t NH_3
United Arab Emirates to Germany	Ammonia	2022	13 t NH_3
Brunei to Japan	LOHC	2022	
Chile to United Kingdom	Synthetic gasoline	2023	2 600 L
Saudi Arabia to Japan	Ammonia	2023	
Saudi Arabia to India	Ammonia	2023	5 000 t NH_3
Saudi Arabia to China	Ammonia	2023	25 000 t NH_3
Saudi Arabia to Korea	Ammonia	-	25 000 t NH_3
Saudi Arabia to Bulgaria	Ammonia	2023	25 000 t NH_3
Saudi Arabia to European Union	Ammonia		50 000 t NH_3
Saudi Arabia to Chinese Taipei	Ammonia	2023	

* The shipped hydrogen was produced from unabated coal, although the commercial phase of the project plans to include carbon capture, utilisation and storage (CCUS).

Notes: This table does not include the already existing ammonia trade in the fertiliser industry. Around 10% of global ammonia production for the fertiliser industry is already traded today, but this is almost entirely based on ammonia production from unabated fossil fuels. Projects characterised as “low-carbon” or “blue” ammonia or hydrogen are included, although information on the emission reduction compared to the unabated production from fossil fuels is not always available.NH_3 = ammonia; H_2 = hydrogen; LH_2 = liquefied hydrogen; LOHC = liquid organic hydrogen carrier.

For synthetic hydrocarbon fuels, the pilot phase of the Haru Oni project in Chile started production of synthetic gasoline in December 2022, and a first shipment of 2 600 litres (L) of synthetic gasoline left Chile for the United Kingdom in March 2023. The current pilot plant has a production capacity of 130 000 L per year (corresponding to the annual fuel consumption of 200 gasoline passenger cars)[57], with the plan to ramp up the capacity to 55 million L by 2025 (83 000 cars) and 550 million L by 2027 (830 000 cars). Synthetic hydrocarbon liquid fuels or synthetic methane can take advantage of existing fossil fuel infrastructure.

Announced trade projects

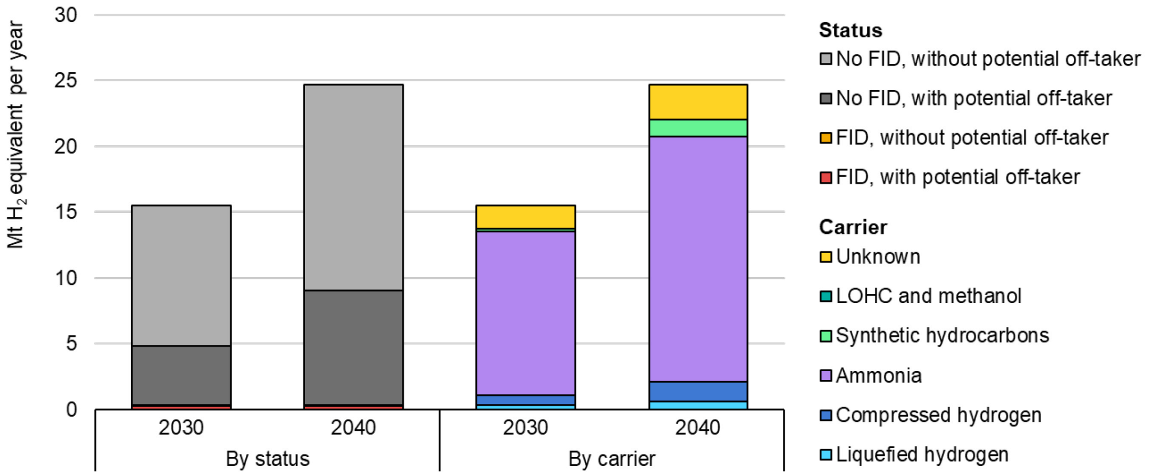
Based on announced export-oriented projects, 16 Mt of hydrogen equivalent (Mt H_2-eq)[58] could be exported all around the world by 2030, and this number could rise to 25 Mt H_2-eq by 2040[59] (Figure 4.1). This is based on announced export plans for which there is an associated hydrogen production project, including those plans at very early stages of development (e.g. projects that have not yet started a feasibility study). Export-oriented projects represent more than 40% of the low-emission hydrogen production of 38 Mt from all announced projects in 2030, indicating that the potential export market is a strong driver in the development of projects. Compared to last year's edition of the Global Hydrogen Review, the 16 Mt H_2 of announced trade projects represent a more than 25% increase. Despite this growth in announced trade projects, progress in pre-existing projects has been slow. Only three projects are at advanced stages of development, i.e. having at least reached a final investment decision (FID): the NEOM project in Saudi Arabia, the Green Hydrogen and Chemicals SPC project in Oman and CF Industries' plant in Donaldsonville in the United States. All three of these projects aim to use ammonia as the carrier for a combined export volume of less than 0.3 Mt H_2-eq by 2030.

Three-quarters of the export-oriented projects planned for 2030 or sooner are still at early stages of development and only less than one-quarter is undergoing a feasibility study. Moreover, less than one-third of the volume that could be traded by 2030 has already identified a potential off-taker – although only a few have reached FID or signed a binding off-take agreement. This is the case of the NEOM Green Hydrogen Project in Saudi Arabia: a 30-year off-take agreement has been secured with Air Products for the low-emissions ammonia produced from 2026 onwards. The realisation of the announced trade projects will depend not only on the deployment of the production facility and the necessary infrastructure, but also on securing one or more off-takers for the long run: these two aspects should be pursued in parallel to ensure that projects are realised on time and are economically sustainable. Despite the strong momentum around hydrogen export announcements in the past few years, the small share of trade projects that have

[57] Assuming a fuel efficiency of 6.6 L per 100 km and an annual mileage of 10 000 km.
[58] For hydrogen-based fuels and feedstocks, the equivalent hydrogen amount corresponds to the stoichiometric hydrogen inputs needed to produce these fuels feedstocks, assuming a 2% hydrogen loss in the reaction. The hydrogen requirements are 0.18 kg H_2 per kg NH_3, 0.13 kg H_2 per kg methanol, 0.52 kg H_2 per kg of Fischer-Tropsch synfuel and 0.55 kg H_2 per kg of methane.
[59] In the case of hydrogen-based fuels as carriers, the hydrogen equivalent amount represents the hydrogen feedstock needed to produce the carrier chosen for trade.

reached advanced planning stages demonstrates significant uncertainty around the ability to develop an export market at scale over the next decade.

Figure 4.1 Low-emission hydrogen trade by status and by carrier based on announced projects, 2030-2040



Notes: FID = final investment decision; LOHC = liquid organic hydrogen carrier. “Compressed hydrogen” includes both projects aiming to transport gaseous hydrogen via pipelines and projects planning to ship it in compressed hydrogen carrier. “Synthetic hydrocarbons” includes projects aiming to trade synthetic methane or synthetic oil products. “No FID” refers to projects undergoing feasibility study or at early stage, while “FID” indicates projects that have already reached a final investment decision. “Potential off-taker” refers to projects which have identified a potential buyer or end-user, even if a binding off-take agreement has not been signed yet. The amount of hydrogen equivalent traded is computed from the capacity of each plant, by considering average capacity factors (reported in the technical documentation of the IEA Hydrogen Projects Database) and by assuming that a certain share of production would be available for trade, in the case of projects aiming at multiple end-uses. For each project, a 50% availability factor is assumed for the first year of operation. Only projects with a disclosed start year are included.

Source: IEA analysis based on multiple sources, including company announcements.

Planned hydrogen exports could reach 16 Mt by 2030, though almost all projects are at early stages and fewer than one-third have identified a potential off-taker.

The majority of announced projects – accounting for 80% of potential production – prioritise ammonia for the transport of hydrogen, in many cases aiming for a final use that does not require reconversion back to hydrogen (Figure 4.1). This includes use as feedstock in the fertiliser industry, or as a fuel for co-firing in power generation. Reconversion back to hydrogen requires energy and adds significant cost, potentially altering the economic competitiveness of the supply chain (see Infrastructure at ports).

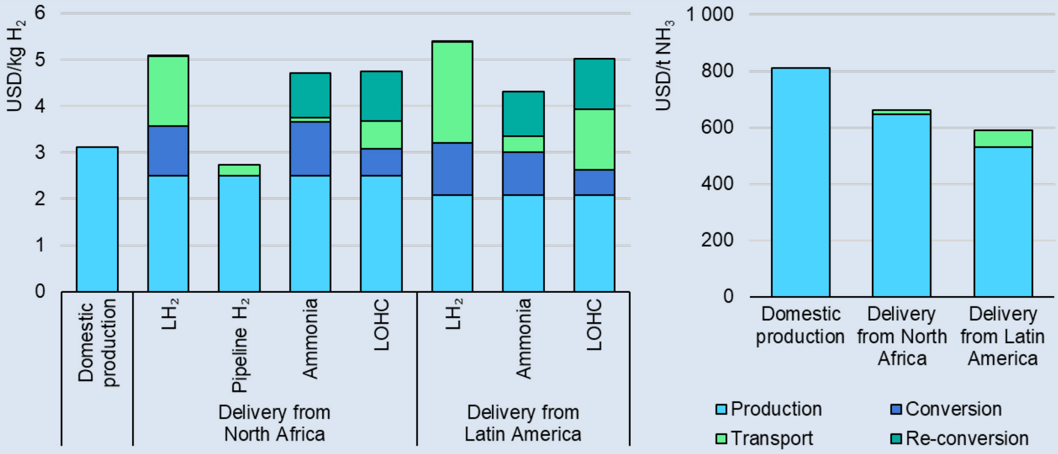
Many projects are at an early stage of development, and for several of them the carrier has not yet been chosen. By 2040, about 5% of the traded volume based on the announced trade projects could be in the form of synthetic liquid hydrocarbons, 4% as compressed gaseous hydrogen via pipeline, and 2% in the form of liquefied hydrogen.

The costs of importing hydrogen compared to domestic production are also influenced by the form in which the hydrogen will eventually be needed, as illustrated in Box 4.1.

Box 4.1 Domestic production versus imports – the case of north-west Europe

The cost of transporting hydrogen from the exporting to the importing region can be substantial, and so assessing the total cost of supply – for production and transport – is essential. Depending on the carrier and the transport distance, transport costs can shift the competitiveness in favour of domestic production. For example, at USD 2.1/kg H_2, levelised production costs in Latin America are cheaper than domestic production from offshore wind in north-west Europe. However, adding the transport costs of USD 2.5/kg H_2 (including conversion into ammonia in the exporting country and its reconversion into hydrogen in north-west Europe) makes domestic production the cheaper option, although constraints on renewable resources or alternative uses for the renewable electricity could limit domestic production.

Supply costs of hydrogen and ammonia in north-west Europe compared to imports



Notes: "H_2"= hydrogen; "NH_3" = ammonia; "LH_2" = liquefied hydrogen; "LOHC" = liquid organic hydrogen carrier. Domestic production in north-west Europe uses offshore wind; production in other regions uses solar PV. "Conversion" includes a compressed hydrogen storage cost to allow for stable input to the synthesis and to the liquefaction processes. The cost of capital is assumed at 6%. Costs refer to the Net Zero Emissions by 2050 Scenario (NZE Scenario) in 2030. More techno-economic assumptions are available in a separate forthcoming Annex.

Sources: Based on data from McKinsey & Company and the Hydrogen Council; IRENA (2020); IEA GHG (2014); IEA GHG (2017); E4Tech (2015); Kawasaki Heavy Industries; Element Energy (2018).

Transporting compressed hydrogen via pipeline can be the most competitive option in terms of cost, adding only about USD 0.4-0.5/kg H_2 for a 3 000 km distance with a new 48-inch diameter pipeline (75-100% design capacity). This cost can be even lower if repurposed pipelines are available. However, the feasibility of this type of infrastructure can have technical and geopolitical challenges.

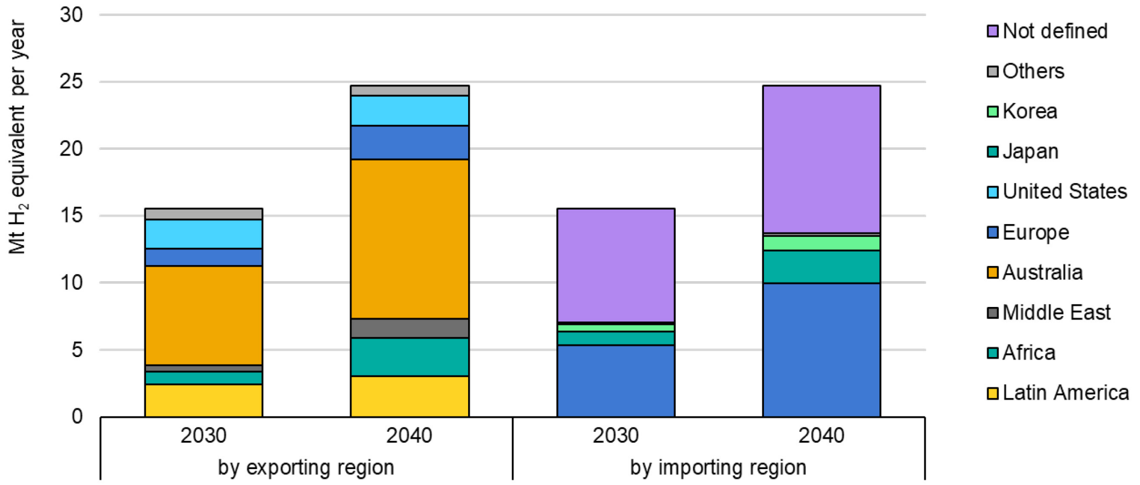
The form in which the imported hydrogen will eventually be used strongly influences the choice of hydrogen carrier and the supply costs. If hydrogen is consumed in the form of ammonia and not hydrogen, for example in the fertiliser industry, the imported ammonia can be used directly, avoiding the costs of reconverting ammonia back into hydrogen. In this case, importing ammonia from North Africa, Latin America or the Middle East can actually be cheaper than domestically producing ammonia in north-west Europe.

Given that some of the technologies required for conversion, shipping and reconversion are at a relatively early stage of development, with just a few pilot or demonstration projects having been realised so far, the economics of the different trade options may change in the future, as technologies advance.

Australia is home to half of the trade projects by export volume, thanks to its abundant renewable resources and its proximity to the Asian market, which could potentially become one of the biggest importers of low-emission hydrogen and hydrogen-based fuels. Several GW-scale renewables-based hydrogen production projects are planned in Australia and many of them, such as the Murchison project and the Australian Renewable Energy Hub, aim to export to international markets. Central and South America and North America together could represent one-third of the exported hydrogen by 2030. Africa and Europe could account for 6% and 8% by 2030, respectively. However, all of the Europe-based exported hydrogen is set to remain within the continent as the projects aim to connect countries with relatively good renewable resources (such as Denmark) with demand centres in the Netherlands and Germany. Large-scale export-oriented projects have also been announced in Oman and the United Arab Emirates, but they represent only a few percent of the global trade volume by 2030, with the Middle East region accounting for 6% of global export by 2040 only.

Around 60% of the announced projects by 2030 have not yet identified a destination country, and of the projects that have done so, about two-thirds have identified a potential off-taker. Based on the current announced projects, Europe could receive 5 Mt H_2-eq by 2030, with one-fifth of it having been produced and traded inside the region itself. This could double to around 10 Mt H_2-eq by 2040, with two-thirds of these imports in the form of ammonia. Japan could receive 1 Mt H_2-eq by 2030, with supply coming predominantly from North America and Australia.

Figure 4.2 Low-emission hydrogen trade by exporting and importing region based on announced projects, 2030-2040



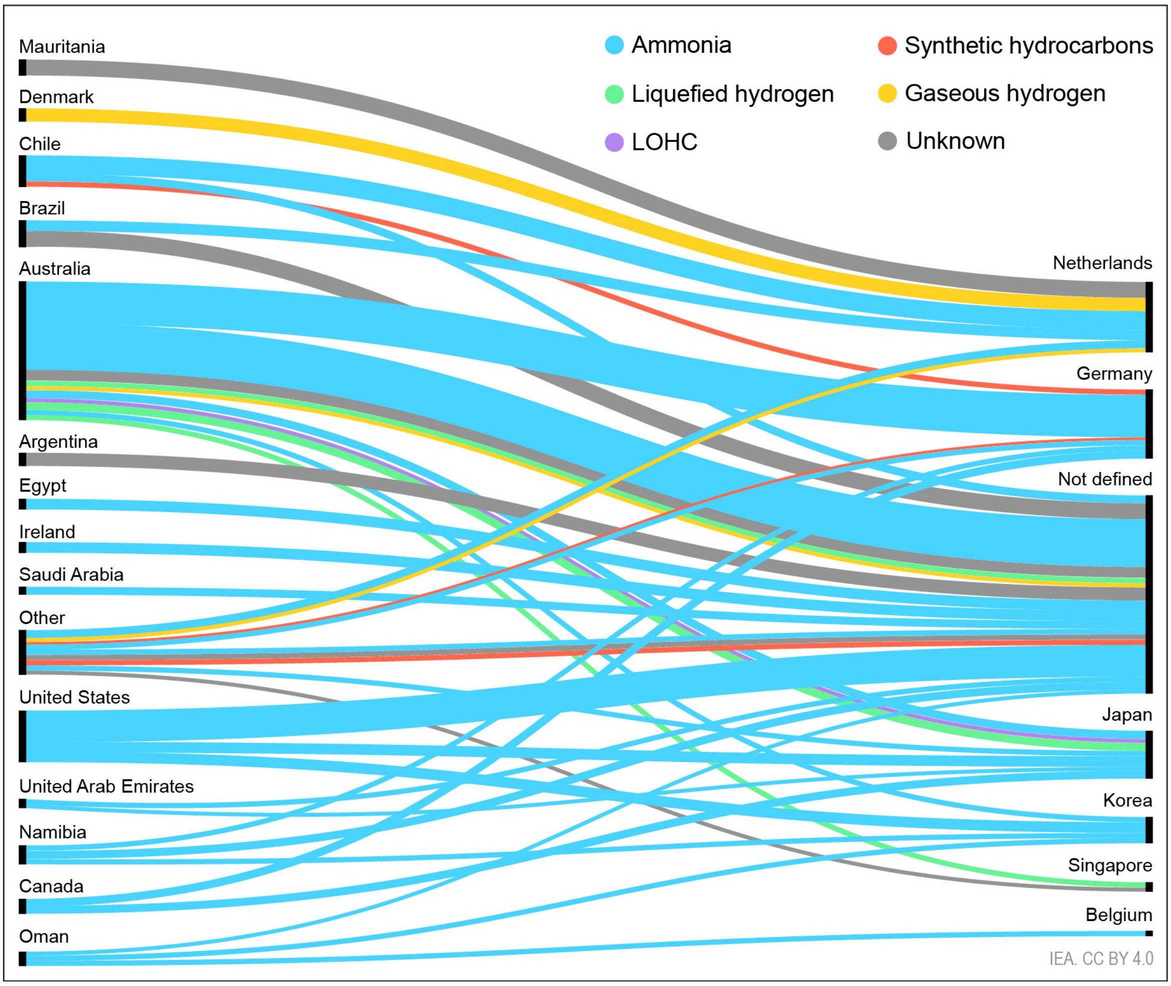
Notes: The amount of hydrogen equivalent traded is computed from the capacity of each plant, by considering average capacity factors (reported in the technical documentation of the IEA Hydrogen Projects Database) and by assuming that a certain share of production would be available for trade, in the case of projects aiming at multiple end-uses. For each project, a 50% availability factor is assumed for the first year of operation. Only projects with a disclosed start year are included.
Source: IEA analysis based on multiple sources, including company announcements.

Australia accounts for half of the announced export projects by 2030, while around one-third of the announced exports globally are earmarked for Europe. Still, around 60% of export projects have not yet identified a destination country.

The major trade routes that can be identified based on announced projects connect Australia with Europe and with the Asian market (Japan and Korea in particular), Latin American countries with Europe, and North American countries with the Asian market (Figure 4.3). On all these routes, ammonia is expected to be the main carrier to transport low-emission hydrogen by 2030.

Although more and more countries are publishing national hydrogen strategies, or roadmaps defining hydrogen development milestones for the next decades, not all of them have quantitative objectives for production, and only a few for expected trade volumes (Figure 4.4). The REPowerEU plan sets a target of 10 Mt of renewable hydrogen imports into the European Union by 2030, of which 40% should be in the form of ammonia or other derivatives. Korea aims to import 1.94 Mt H_2 by 2030, according to the Basic Plan for Implementation of Hydrogen Economy. These combined targets together represent almost 12 Mt of hydrogen imports by 2030, more than twice the volume from announced projects planning to deliver to these destinations (including those at very early stages of development). Reaching those targets – and also reaching the ambition levels reflected in project announcements – will require rapid and concrete actions for reaching FIDs and moving forward with construction, not only of the underlying hydrogen production projects, but also of the trade infrastructure.

Figure 4.3 Potential low-emission hydrogen trade flows based on announcements, 2030



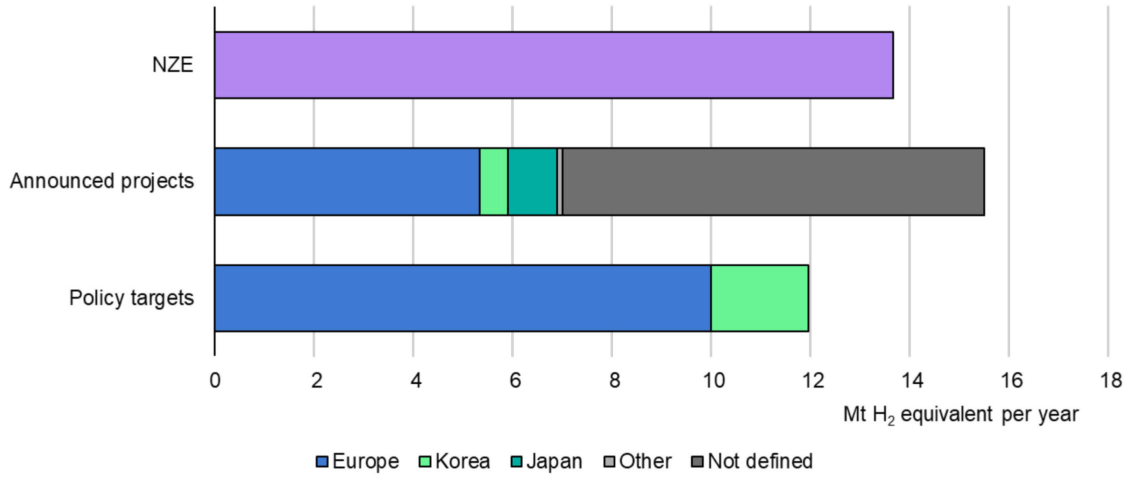
Notes: LOHC = liquid organic hydrogen carrier; UAE = United Arab Emirates; Mt = million tonnes. In million tonnes of hydrogen equivalent, only flows larger than 150 kt H_2 equivalent per year are shown.
Source: IEA analysis based on multiple sources, including company announcements.

Several trade projects are under development, with Australia, Central and South America, North America and Africa as key exporters, while only a few importing countries have been identified.

Where a project cannot take advantage of pre-existing terminals or pipelines, infrastructure will need to be developed in parallel to plant construction, as building new infrastructure can often be the lengthiest part of all construction, with pipelines and port terminals taking up to 9 years on average. At the same time, contracts with off-takers need to be secured to guarantee the economic sustainability of the project.

In the NZE Scenario, 14 Mt of hydrogen equivalent are traded inter-regionally[60] by 2030, corresponding to about 25% of low-emission merchant hydrogen production. The volume of the announced trade projects is comparable with the trade volume in the NZE Scenario. Those projects with a defined destination represent only half of the trade in the NZE Scenario in 2030 and those with a potential off-taker only one-third. Almost two-thirds of the trade in the NZE Scenario is in the form of ammonia, while around half of the hydrogen traded in its pure form is transported via pipeline.

Figure 4.4 Low-emission hydrogen trade by importing region based on announced projects, policy targets and in the Net Zero Emissions by 2050 Scenario, 2030



Notes: NZE=Net Zero Emissions by 2050 Scenario. The amount of hydrogen equivalent traded is computed from the capacity of each plant, by considering average capacity factors (reported in the technical documentation of the IEA Hydrogen Projects Database) and by assuming that a certain share of production would be available for trade, in the case of projects aiming at multiple end-uses. For each project, a 50% availability factor is assumed for the first year of operation.
Sources: IEA analysis based on multiple sources, including company announcements, RePowerEU, Korea Basic Plan for Implementation of Hydrogen Economy.

Policy targets by countries for hydrogen imports are twice as high as the announced export projects to deliver to those countries.

One current obstacle for trade is the lack of a common internationally agreed methodology to determine the emission intensity of hydrogen, which could potentially lead to a fragmented market for hydrogen (see Chapter 6).

[60] In the scenario analysis, only the trade flows between the model regions of the IEA's Global Energy and Climate Model (GEC-M) are represented, which means that trade between countries that are part of the same region is not captured. For announced projects, bilateral trade flows between countries are represented.

Trade contracts

Bilateral trade arrangements, often between companies, but in some cases also involving government institutions, currently account for the majority of announced trade projects with an identified off-taker. These **bilateral trade contracts** with clear pricing mechanisms or fixed prices provide investment security to develop capital-intensive hydrogen projects such as production facilities or trade infrastructure. **Auctions** are another instrument for awarding trade contracts: by creating a bidding competition for a contract, auctions can help move the demand- and supply-side price levels closer. They also allow the market price to respond more readily to changes such as production cost declines or increased willingness to pay.

One of the most developed support instruments for hydrogen trade today is the H2Global double-auction programme initiated by Germany. Using a market intermediary, an auction will be held to purchase hydrogen from suppliers outside the European Union through fixed price 10-year contracts. A separate auction will then be held to sell the hydrogen to buyers using contracts of roughly 1 year. H2Global launched first tenders with a budget of EUR 900 million for ammonia, synthetic methanol and synthetic kerosene produced from renewable hydrogen at the end of 2022, with deliveries planned to begin in 2024. The tenders were closed by the end of May 2023. The German government has allocated a further EUR 3.5 billion for future tenders up to 2036. The tender conditions follow the rules of the EU Renewable Energy Directive II and the delegated act on rules for the production of renewable liquid and gaseous transport fuels of non-biological origin. This means that the electricity must come from directly connected renewables, from an electricity grid with at least a 90% renewable share or from a power purchase agreement (PPA). For the PPAs, H2Global requires hourly correlation, i.e. renewable electricity generation and its use in hydrogen production must balance within an hour. This is stricter than the use of monthly correlation (i.e. balancing within a month) until 2030 stipulated in the final version of the delegated act. The H2Global initiative is not limited to Germany, but can be used by other countries, and the Dutch government announced it will use H2Global for auctions of hydrogen imports in 2024, with allocated government support of EUR 300 million.

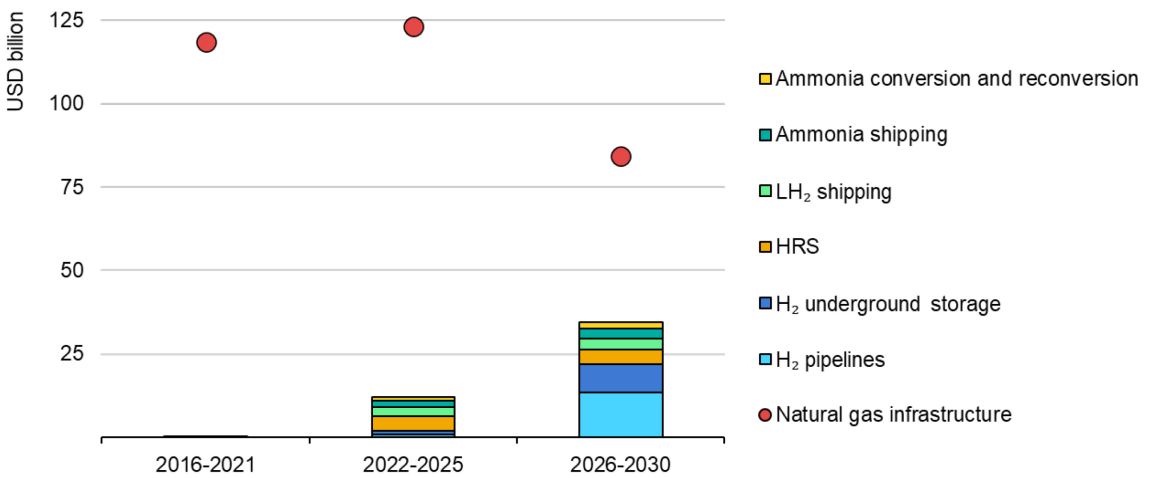
In 2023, the European Commission established the European Hydrogen Bank to stimulate renewable hydrogen production and use. The European Hydrogen Bank plans a pilot auction on a fixed premium for renewable hydrogen production within the European Union for Q3 2023, with a budget of EUR 800 million and with contracts to be awarded by mid-2024. Similar tenders for renewable hydrogen imports from outside the European Union are also planned. Joint auctions of the European Hydrogen Bank and H2Global are being discussed.

The use of auctions and tenders is not limited to governments. In February 2022, the Japanese utility JERA issued a tender for up to 500 000 t/yr of low-emission ammonia to be co-fired in its Hekinan coal power plant, with deliveries starting in 2027-28 and lasting into the 2040s. Two companies, Yara and CF Industries, won the tender and plan to produce the ammonia in the United States from natural gas with CCUS.

Status and outlook of hydrogen infrastructure

Transport and storage are critical elements of the low-emission hydrogen supply chain. Infrastructure is needed not only to connect regions where low-emission hydrogen can be produced at low cost with centres of demand and to manage fluctuations in production and demand, but also to ensure the resilience of the system in the event of supply disruptions.

Figure 4.5 Global annual investment in gas infrastructure in the Net Zero Emissions by 2050 Scenario, 2016-2030



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Notes: H_2 = hydrogen; HRS = hydrogen refuelling stations; LH_2 = liquefied hydrogen.

Total investment in natural gas and hydrogen infrastructure remains steady, with USD 35 billion dedicated to hydrogen by the end of this decade in the NZE Scenario.

In the NZE Scenario, global annual investment in low-emission hydrogen and hydrogen-based fuels transport, including pipelines, storage facilities, terminals and refuelling stations, reaches around USD 35 billion over the second half of this decade. This amount represents approximately 40% of current annual spending on natural gas pipelines and shipping infrastructure (Figure 4.5). However, as investment in natural gas infrastructure declines in the NZE Scenario, the overall level of investment in infrastructure for gas and hydrogen infrastructure combined remains relatively steady throughout the decade.

The development of energy infrastructure projects generally tends to have long lead times, averaging between 6 and 12 years for natural gas pipelines, port terminals and underground gas storage facilities. Gas infrastructure projects are large civil engineering projects, often spanning several jurisdictions, which can entail delays due to permitting issues and a lack of socio-political support. It is therefore critical to start infrastructure planning well in advance, even before production and demand are fully established.

Currently, there are around 1 million km of natural gas transmission pipelines in operation, 60 000 km under construction and over 150 000 km under consideration. As natural gas consumption declines, repurposing this existing infrastructure for hydrogen would provide an opportunity to mitigate the risk of stranded assets. It would reduce the environmental impact associated with manufacturing and laying new pipelines, thereby lowering investment costs and potentially reducing lead times. Around 5 000 km of hydrogen pipelines are already in operation worldwide, mainly in the United States and Europe. These pipelines are relatively small, with diameters of less than 18 inches, connecting refineries and chemical complexes, operating under static loads and all onshore. However, new hydrogen pipelines connecting countries or continents may be larger, with diameters as large as 48 inches. These pipelines could connect different countries and even continents, with some of them being offshore, and could provide a certain degree of flexibility to the system as they should be able to withstand pressure swings resulting from cyclic loading and some linepack.[61] Such a – rather futuristic – hydrogen transmission system would differ significantly from existing local networks, and would more closely resemble current natural gas transmission, albeit on a smaller scale, as hydrogen consumption would be lower than today's natural gas consumption, even in the NZE Scenario.

Global underground natural gas storage capacity is around 490 bcm, equivalent to approximately 12% of annual gas demand. In Europe, this figure is as high as 25% in order to cover seasonal increases in heating demand. Around 90% of existing capacity is in porous reservoirs, mainly depleted gas fields. The capacity requirements and the type of storage needed for low-emission hydrogen are expected to be different to those for natural gas. Hydrogen demand may be less seasonal, but countries will still need to determine an appropriate level of storage for security purposes, considering import dependencies. However, intra-seasonal

[61] Linepack refers to the volume of gas stored in a pipeline. The gas can be compressed, increasing the pressure of the pipeline. Since the pipeline can operate within a safe pressure range, the amount of gas injected into a pipeline may differ from the amount of gas withdrawn at a specific time, providing short-term operational flexibility to match supply and demand.

fluctuations due to the variability of renewable energy generation will mean that hydrogen storage would require underground facilities that can go through multiple cycles within a year. Depending on geologic availability, salt cavern storage or lined hard rock cavern storage are favourable options for managing fluctuations in renewable energy and hydrogen production, even if they are more expensive in terms of rated capacity. Porous reservoirs are more commonly available, but their

flexibility to rapidly ramp up and down is still uncertain, and the technology has not yet been demonstrated for pure hydrogen storage, but they could potentially play a key role in enhancing security.

To transport hydrogen over long distances where pipeline transmission is not feasible, or in regions without suitable geological conditions for underground storage, hydrogen needs to be converted into denser forms. Among such alternatives, liquefied hydrogen (LH_2) or carriers such as ammonia and LOHCs are promising options. However, while the conversion of hydrogen to ammonia for use as ammonia is already well established, if conversion back to hydrogen is needed the technologies required are not yet available on a commercial scale.

Transport by pipeline

Whenever hydrogen transport by pipeline reaches economies of scale (~100 kilotonnes per year [ktpa] for a 20-inch pipeline and ~2 000 ktpa for a 48-inch pipeline operating at 75% of their design capacity and 50-80 bar), it will become the cheapest option for hydrogen transport up to a distance of 2 000-2 500 km, particularly in the case of repurposed pipelines. Large-diameter pipelines may be cheaper for longer distances, but their construction is more challenging, especially if they cross different jurisdictions.

Some regions and countries are already working on the legal and regulatory adjustments needed to trigger deployment of dedicated hydrogen infrastructure. In December 2021, the European Commission adopted a legislative proposal to recast the 2009 EU Gas Directive, proposing a Hydrogen and Decarbonised Gas markets package, which aims to put forward measures to support the creation of dedicated hydrogen infrastructure. In March 2023, EU energy ministers agreed on the Council's position, and the legal acts should be formally adopted once an agreement is reached with the European Parliament. The hydrogen package proposal seeks to develop competitive hydrogen markets, unbundling[62] hydrogen transmission and setting a series of incentives for repurposing natural gas infrastructure, and to attract investments for cross-border infrastructure.

[62] Unbundling refers to the separation of activities potentially subject to competition, such as hydrogen production, from those where competition is not possible or allowed, e.g. transmission and distribution, which is a regulated monopoly in the European Union. This would allow the independent transmission system operator model under certain conditions.

Belgium already has an extensive hydrogen network connecting to France and the Netherlands, spanning around 600 km (the largest network in Europe and second in the world after the United States) and owned by Air Liquide. Belgium passed pioneering legislation on the transport of hydrogen by pipelines, the first of its kind in the world, which entered into force in August 2023. This law aims to regulate hydrogen transmission networks, establish criteria for designating a single hydrogen transmission system operator, and entrust it with various responsibilities, including strategic planning, ensuring free and non-discriminatory access to the network and guaranteeing the quality of the hydrogen transported.

In May 2023, the Danish government selected the state-owned companies Energinet and Evida to own and operate Denmark's forthcoming hydrogen pipelines. This decision follows the Power-to-X tender that Denmark launched in April 2023. The government also announced its intention to present a financing proposal for the hydrogen transmission network by the end of 2023.

Also in May 2023, the German Federal Cabinet passed a draft law to create the legal and regulatory framework for a future hydrogen transmission system, expected to be operational by 2032. In July 2023, Germany's gas system operators presented a draft of a potential hydrogen transport network of 11 200 km and 60% of repurposed natural gas pipelines, with a final version to be submitted to the regulator BNetzA for approval by Q3 2023.

In August 2023, the UK government published proposals for hydrogen transport business models, as a result of a consultation process. The proposals suggest a Regulated Asset Base model alongside an external subsidy mechanism in the early stages, avoiding very high transport costs when the network is not yet fully utilised, while preventing excessive returns to developers.

Project announcements for dedicated pipelines

There have been substantial project announcements for hydrogen transmission pipelines across and between countries during the past year, and a detailed list of project announcements for the construction of new hydrogen pipelines or the repurposing of natural gas pipelines for hydrogen can be found in the IEA Hydrogen Infrastructure Database.[63]

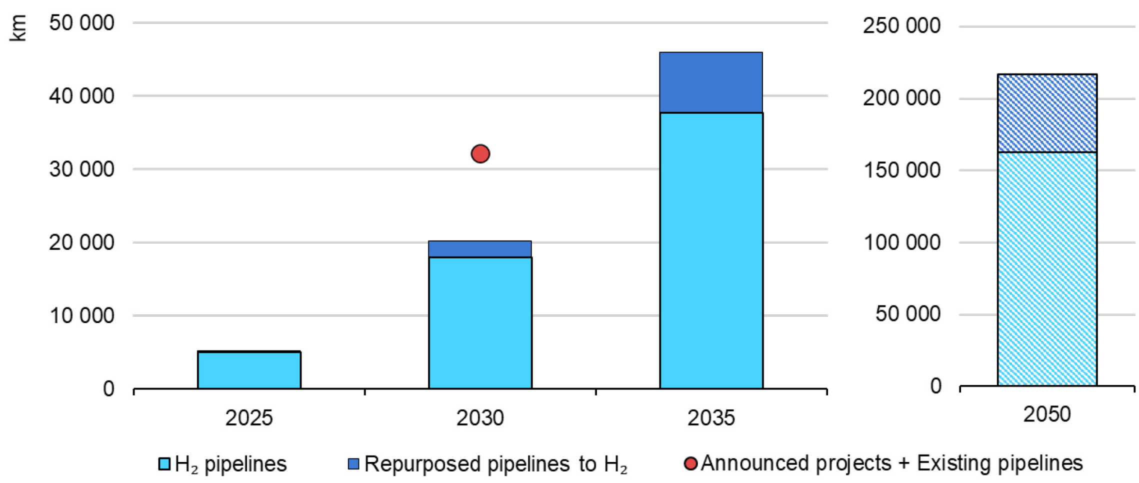
In Europe, the European Hydrogen Backbone initiative involves 33 gas infrastructure operators from 25 EU member states, as well as Norway, Switzerland and the United Kingdom. This initiative envisions a 33 000 km pan-European hydrogen pipeline network by 2030, based on repurposed natural gas pipelines wherever possible. The 2022 revised Trans-European Networks for

[63] For release in October 2023.

Energy (TEN-E) Regulation, which focuses on linking the energy infrastructure between EU countries, now includes support for hydrogen infrastructure. It identifies three priority hydrogen corridors: hydrogen interconnections in Western Europe, hydrogen interconnections in Central Eastern and Southeastern Europe, and a Baltic Energy Market Interconnection Plan in hydrogen.

Outside of Europe, China's first trans-regional hydrogen pipeline has been included in its Implementation Plan for the Construction of a National Oil and Gas Network, issued in 2023. This would transport hydrogen from Ulanqab (North China's Inner Mongolia Autonomous Region) to Beijing, with a length of more than 400 km and a capacity of 100-500 ktpa. In 2023, the state-owned China Petroleum Pipeline Engineering Corporation suggested that the country may need 6 000 km of hydrogen pipelines by 2050. In Oman, the Ministry of Energy has stated that hydrogen pipeline infrastructure will initially be situated around the ports in the south of the country, potentially connecting to nearby salt caverns, and later on other northern cities could be connected to the pipeline network, including Muscat. In June 2023, OQ Gas Networks, Oman's gas transportation system operator, signed a memorandum of understanding with Hydrogen Oman (Hydrom) to explore the development of a hydrogen network.

Figure 4.6 Global hydrogen transmission pipeline length in the Net Zero Emissions by 2050 Scenario and announced projects, 2020-2050



IEA. CC BY 4.0.

Note: km = kilometre.

The length of announced hydrogen pipelines over the next decade is in line with the needs of the NZE Scenario, if projects – most of which are at an early stage – come to fruition.

No offshore hydrogen pipeline is in operation today. Despite this limited experience and related uncertainties, several offshore pipeline projects have been announced. In June 2023, Gasunie launched a tender for a feasibility study for an offshore hydrogen pipeline in the North Sea, including the design of the offshore platform (compression/electrolysis) and the pipeline routing. In January 2023, Norway and Germany commissioned a joint feasibility study to assess large-scale transport of hydrogen from Norway to Germany, and CO_2 transport from Germany to Norway for offshore storage. The feasibility study is being carried out by Gassco (Norway's gas operator) and dena (the German energy agency), and in September 2023 the two countries set up a joint task force to follow up on the results.

Other offshore pipelines are being considered, albeit still at a conceptual stage, between Spain and France (H_2Med - Bar-Mar); Algeria/Tunisia and Italy (SouthH_2 Corridor); Finland, Sweden, Denmark and Germany (Baltic Sea Hydrogen Collector); Denmark and Germany (H2 Interconnector Bornholm Lubmin). Offshore pipelines in the North Sea are being considered more generally, such as the AquaDuctus project (Germany), and as highlighted by the Ostend Declaration of Energy Ministers signed in April 2023 by Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway and the United Kingdom. If offshore wind is going to be used for hydrogen production, the offshore production of hydrogen and its delivery to the coast by pipeline can, in some cases, become an alternative to transporting electricity for onshore hydrogen production (Box 4.2).

Nevertheless, uncertainties in production and demand, and the current limited regulatory framework, may not be sufficient to provide financial and legal certainty to potential investors in low-emission hydrogen infrastructure. While the length of announced projects adds up to almost 30 000 km by 2030, and is aligned with the needs of the NZE Scenario (Figure 4.6), the combined length of projects having reached FID is minimal (Table 4.2). However, as a first step, several calls have been launched in 2023 to confirm interest in hydrogen transmission infrastructure, typically including an initial non-binding phase to understand market needs and conduct feasibility studies. This will be followed by a second binding phase to contract transmission capacity, which will lead to investment decisions.

Table 4.2 Progress between Q3 2022 and Q2 2023 on hydrogen transmission projects in new and repurposed pipelines

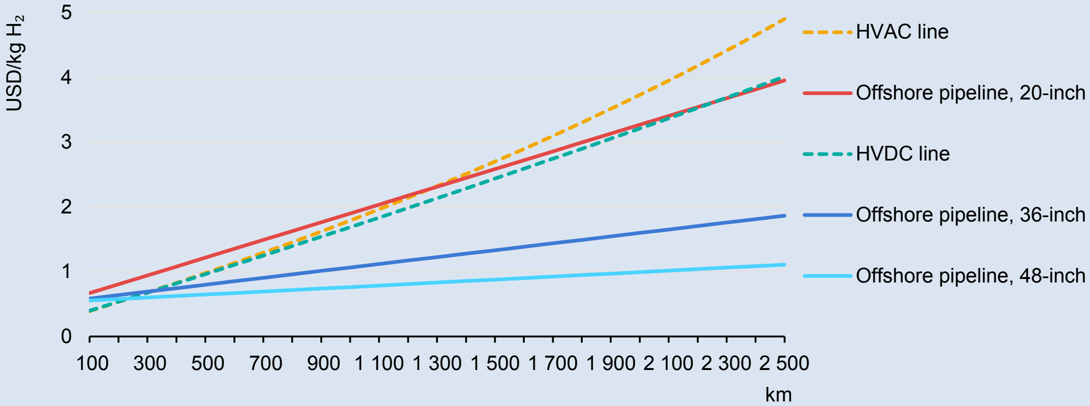
Country	Length	Date	Status
Australia	43 km	May 2023	APA completed pressurised 100% hydrogen testing in a repurposed section of the Parmelia Gas Pipeline. Detailed conversion plans will follow.
Belgium	-	July 2023	Ministers Council agreed on a EUR 250 million subsidy to develop a hydrogen pipeline network connecting to Germany and industrial clusters in Ghent, Antwerp, Mons, Charleroi and Liège.
France	150 km	January –	GRTgaz launched a non-binding call to confirm economic interest in the Hynframed project, linking up

Country	Length	Date	Status
		March 2023	the Fos-sur-Mer industrial and port area with storage facilities in Manosque, expected by 2028. This will be followed by a binding Open Season process to contractually determine transmission capacities.
France-Belgium	70 km	June – September 2022	GRTgaz and Fluxys launched a call (non-binding phase) to assess interest in a hydrogen pipeline between Valenciennes (France) and Mons (Belgium). 17 companies expressed their interest, and a feasibility study was launched.
Germany	50 km	June 2023	FID for Bad Lauchstädt Energy Park, including a pipeline to TotalEnergies Refinery.
Hungary	-	July – September 2023	FGSZ has launched a call for interest (non-binding phase) for hydrogen transmission capacity in the Hungarian network and interconnection points with Austria, Croatia, Romania, Serbia, Slovakia, Slovenia and Ukraine.
Netherlands	30 km	June 2023	Gasunie reached FID (more than EUR 100 million) for the first section of its planned hydrogen backbone (1 200 km) in Rotterdam, from the Tweede Maasvlakte to Pernis. Construction starting in Q3/Q4 2023 and commissioning expected by 2025.
Netherlands	270 km	May - July 2023	Publication of the "Intention and proposal for participation" for the Delta Rhine Corridor, which envisages the construction of several pipelines, including for hydrogen, between Rotterdam, via Moerdijk, to Chemelot industrial park in Geleen and to the German border. The Dutch Ministry of Economic Affairs and Climate and Gasunie invited stakeholders to contribute to the spatial planning for the design of the project.
Spain	-	September – November 2023	Enagás is launching a non-binding call for interest for hydrogen transport infrastructure. Based on the results, a binding Open Season process could be launched in 2025.

Box 4.2 Offshore hydrogen networks or power transmission to shore to deliver hydrogen?

Less than 10% of announced low-emission hydrogen production by 2030 could rely on offshore wind, equivalent to about 3 Mt H_2. While offshore wind parks are today located relatively close to the coast, new projects are being planned further out to sea. The cost of offshore power transmission for onshore hydrogen production increases relatively quickly with distance, whereas offshore hydrogen production and subsequent transport incurs fixed costs, such as platforms for the electrolysers and AC/DC inverters, leading to higher transport costs for shorter distances compared to offshore power transmission and onshore hydrogen production. For distances of less than 300 km to shore, power transmission may be cheaper than offshore hydrogen production and pipeline transport. However, for longer distances, offshore hydrogen production and transmission may become more cost-effective, especially if it can benefit from the economies of scale of pipelines. There are some uncertainties about the operating pressures of offshore hydrogen pipelines. While offshore natural gas pipelines operate at higher pressures, this could increase the risk of embrittlement with hydrogen and further research is needed.

Cost of offshore hydrogen and power transmission



Notes: HVAC = high voltage alternating current; HVDC = high voltage direct current.

For short distances of offshore hydrogen transport, non-metallic composite pipelines are being explored for their light weight (easier transport and laying), ductility, spoolability and corrosion resistance. Strohm, a developer of thermoplastic composite pipelines, has signed memoranda of understanding (MoUs) with Evonik, Siemens Gamesa, Seanovent and Lhyfe to explore the use of pipelines from polyamide 12, which has low hydrogen permeation. The HOPE project, a consortium co-ordinated by French company Lhyfe, aims to produce 4 t H_2/day and transport it, for the first time, via a 1 km offshore composite pipeline to the port of Ostend (Belgium) by 2026. Other companies, such as SoluForce and Pipelife, have developed a reinforced thermoplastic pipeline for hydrogen applications up to 42 bar, and Long Pipes has developed a composite pipeline technology called Hydrogen Highway.

Hydrogen blending

Blends of natural gas and hydrogen are already being used in several town gas networks in Singapore, Hong Kong and Hawaii, which plan to eventually replace fossil-based hydrogen with low-emission hydrogen.[64]

Since the GHR 2022, a few hydrogen blending demonstration projects have entered operation around the world (Table 4.3); nevertheless, hydrogen blending in distribution networks may sometimes meet strong local opposition. For instance, the United Kingdom's first hydrogen village trial proposal is no longer under consideration by the government due to a lack of support from residents.

Table 4.3 Hydrogen blending projects in gas distribution pipelines entering operation between Q3 2022 and Q2 2023

Project name	Country	Location	Blending volume	Announced size
ATCO Community Blending project	Australia	Cockburn	2-5%	2 700 customers
ATCO Alberta blending project	Canada	Fort Saskatchewan	5%	2 100 customers
Gasvalpo Energas Coquimbo	Chile	Coquimbo	5-20%	2 000 customers
NTPC-GGL in Surat	India	Surat	5%	200 customers
Floene Seixal	Portugal	Seixal	20%	82 customers
20HyGrid project – Delgas Grid	Romania	Dârlos	20%	75 customers
Dominion Energy Utah	United States	Delta	5%	1 800 customers

Hydrogen blending in the transmission network is also being considered, as it could enable the co-utilisation of the existing network until dedicated infrastructure is in place, if deblending and purification technologies become available and cost-efficient. This would likely require a system of guarantees of origin, such as that in place in the Netherlands. In February 2023, Kogas (Korea) selected DNV to assess the feasibility of blending hydrogen into the country's 5 000 km transmission network, as it aims to achieve 20% blending by 2026. In March 2023, the European Union altered the EU Gas Proposal, so that the maximum blending of hydrogen into the natural gas transmission system would be 2% instead of 5% to ensure a harmonised quality of gas. In April 2023, China National Petroleum Corporation announced that it had transported blended hydrogen (24%) using a 397 km gas pipeline in Ningxia for 100 days. In May 2023, Xcel Energy (United States) awarded Worley a study to assess the feasibility of injecting

[64] A list of hydrogen blending projects and their status can be accessed through the IEA Hydrogen Infrastructure Database (October 2023 release).

blended hydrogen in its 58 000 km distribution pipelines and 3 500 km transmission pipelines, including the assessment of blending rates. In June 2023, Portugal's REN announced that it had started adapting its high-pressure natural gas grid (1 375 km) to allow it to carry up to 10% hydrogen. However, deblending technology is not yet available on a large scale. In January 2022, Linde commissioned the world's first full-scale demonstration plant in Dormagen (Germany), which can produce hydrogen with a very high purity from blends of 5-60% using membrane separation followed by pressure swing adsorption.

Underground hydrogen storage

As hydrogen supply expands, underground geological facilities could be needed for storage to balance supply fluctuations caused by variable renewable electricity used in electrolysers and from seasonal changes in demand, as well as to bolster energy security. Salt caverns have been utilised for hydrogen storage in Teesside (United Kingdom) since 1972 and in the Gulf Coast in Texas (United States) since 1983, primarily for chemical and petrochemical processes, with a total capacity of 500 GWh.

New salt cavern facilities for hydrogen storage have been announced and some have made a degree of progress on planning, but none of them have reached FID yet. A detailed list of project announcements for the construction of new underground hydrogen storage facilities or the repurposing of natural gas storage facilities for hydrogen can be found in the IEA Hydrogen Infrastructure Database.[65]

In 2023, for the first time, several calls have been conducted to confirm and quantify interest in underground hydrogen storage facilities (Table 4.4). These calls provide valuable input for estimating facility sizing and ultimately reaching the FID. They are often organised in at least two phases, starting with a non-binding phase, followed by a binding phase if there is sufficient interest. The UK government's proposals for hydrogen storage business models suggest a minimum annual revenue floor for storage providers with contracts negotiated bilaterally between the storage providers and the subsidy provider, protecting against the demand risk.

Table 4.4 Calls for interest for underground hydrogen storage projects

Organiser	Country	Call date	Phase	Description
Géométhane	France	February-March 2023	Non-binding	Assess interest in hydrogen storage in two potential salt caverns (200 GWh of hydrogen) in Manosque.

[65] For release in October 2023.

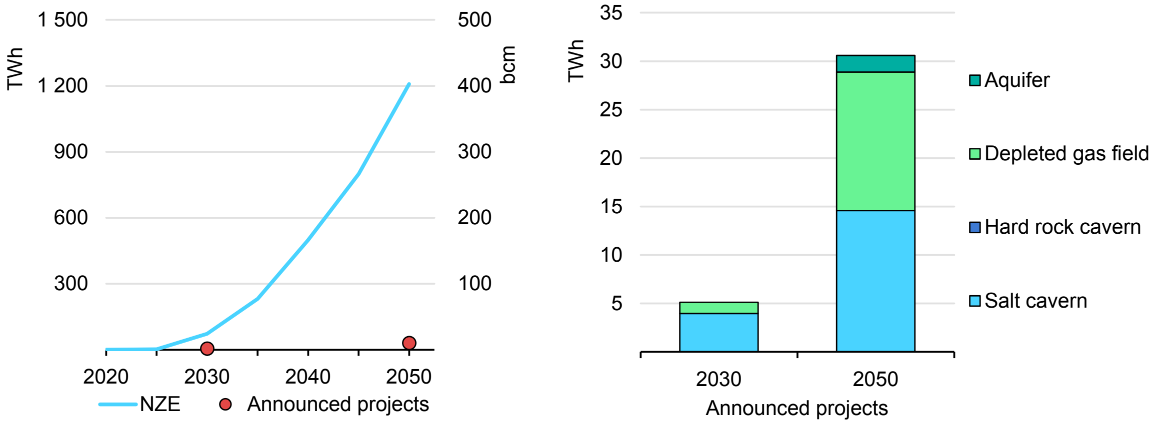
Organiser	Country	Call date	Phase	Description
HyStock (subsidiary of Gasunie)	Netherlands	June-July 2023	Non-binding	Call to reserve capacity (fixed proportion of injection, withdrawal, and storage capacity) in the A5 hydrogen salt cavern (216 GWh) in Zuidwending. Reservations exceed the capacity offered, and an auction will allocate capacity.
Teréga	France	June-October 2023	Non-binding	Assess interest in hydrogen storage in a salt cavern (500 GWh) within the HySoW project (Hydrogen South West Corridor of France).

Furthermore, several salt cavern hydrogen storage projects are progressing. In June 2022, the Advanced Clean Energy Storage project in Utah (United States) secured a conditional Department of Energy (DOE) loan guarantee of USD 504 million. Although FID has not yet been reached, WSP completed drilling and mechanical integrity testing of two salt caverns wells (300 GWh) in May 2023. From November 2022, the H2CAST project conducted a two-month leak test in Etzel (Germany), confirming the tightness of the salt cavern and the use of bore hole equipment with high-pressure hydrogen. The H2CAST project plans to test the conversion of a first salt cavern, formerly used for natural gas storage, for hydrogen storage by the end of 2023. Meanwhile, the HyPSTER project (Etrez, France) aims to demonstrate the impact of hydrogen cyclic storage in salt caverns. In March 2023, it started work to replace the existing equipment in the salt cavern with hydrogen-compatible equipment in preparation for upcoming tests.

In addition to salt caverns, hydrogen might also be stored underground in porous media formations such as depleted oil and gas reservoirs or saline aquifers, although they have not yet been proved for pure hydrogen storage. Hydrogen reactivity has been observed in porous reservoirs when town gas was injected, sometimes resulting in very high consumption of stored hydrogen. However, it remains to be assessed whether these findings would also apply to pure hydrogen storage.

In 2016, in the Underground Sun Storage pilot project (Austria), 115 000 Nm^3 of gas containing 10% H_2 was injected into a depleted gas field for 3 months. About 18% of the hydrogen was not recovered due to diffusion, mixing, dissolution and conversion, while identified methane-producing bacteria converted 3% of the hydrogen. In April 2023, 2 years after the start of the Underground Sun Storage 2030 project, the facility to test the storage of pure hydrogen in a depleted gas field entered into operation in Gampern (Austria), with a capacity of 4.2 GWh of electricity storage (i.e. approx. 2.5 GWh of hydrogen storage). Snam (Italy) verified the possibility of storing up to 100% hydrogen in a lab test unit of two depleted gas fields, and plans to conduct further tests throughout 2023. In September 2023, in the HyStorage project, Uniper will carry out the first hydrogen injections, testing different methane-hydrogen mixtures with 5%, 10% and 25% hydrogen content and storing them for 3 months in a porous rock formation at the Bierwang underground gas storage facility (Germany). In the United States, the DOE is providing USD 6.75 million in funding for the Subsurface Hydrogen Assessment, Storage, and Technology Acceleration (SHASTA) project. SHASTA, running from 2022 to 2024, aims to assess the feasibility of storing pure hydrogen and hydrogen blends in porous reservoirs. In addition, in 2023 the DOE awarded funding for fundamental research to assess the feasibility of using depleted oil and gas fields in Oklahoma, North Dakota and the Appalachian region for hydrogen storage.

Figure 4.7 Global underground geological storage capacity for hydrogen in the Net Zero Emissions by 2050 Scenario and announced projects, 2020-2050



Notes: bcm = billion cubic metres; TWh = terawatt-hour; NZE = Net Zero Emissions by 2050 Scenario. The NZE Scenario assumes that storage capacity equals 3% of total annual hydrogen demand in 2030 and 10% in 2050. “Announced projects” are projects that are not yet operational, including those under construction, with a final investment decision, under feasibility assessment and projects that have been publicly announced, e.g. through a press release or a memorandum of understanding. The year 2050 illustrates announced projects without a specified start year.
Source: IEA Hydrogen Projects, (Database, October 2023 release).

The long lead times associated with underground hydrogen storage projects mean that accelerated action is urgently required to get on track with the NZE Scenario.

Despite recent announcements, the capacity of underground hydrogen storage facilities projects – 5 TWh by 2030 and 30 TWh by 2050 – falls well short of what is required in the NZE Scenario (Figure 4.7). In addition, due to hydrogen’s low density, storing an equivalent amount of energy as hydrogen requires three to four times the volume compared to natural gas at the same pressure. In the NZE Scenario, 74 TWh (26 bcm at normal conditions) of underground hydrogen storage would be needed by 2030, compared to 4 800 TWh (490 bcm) of underground natural gas storage today. By 2050, underground hydrogen storage needs would increase almost twenty-fold, and this substantial rise in physical storage needs would bring them to a level comparable (in terms of volume) to the long-standing underground natural gas storage facilities developed over more than half a century.

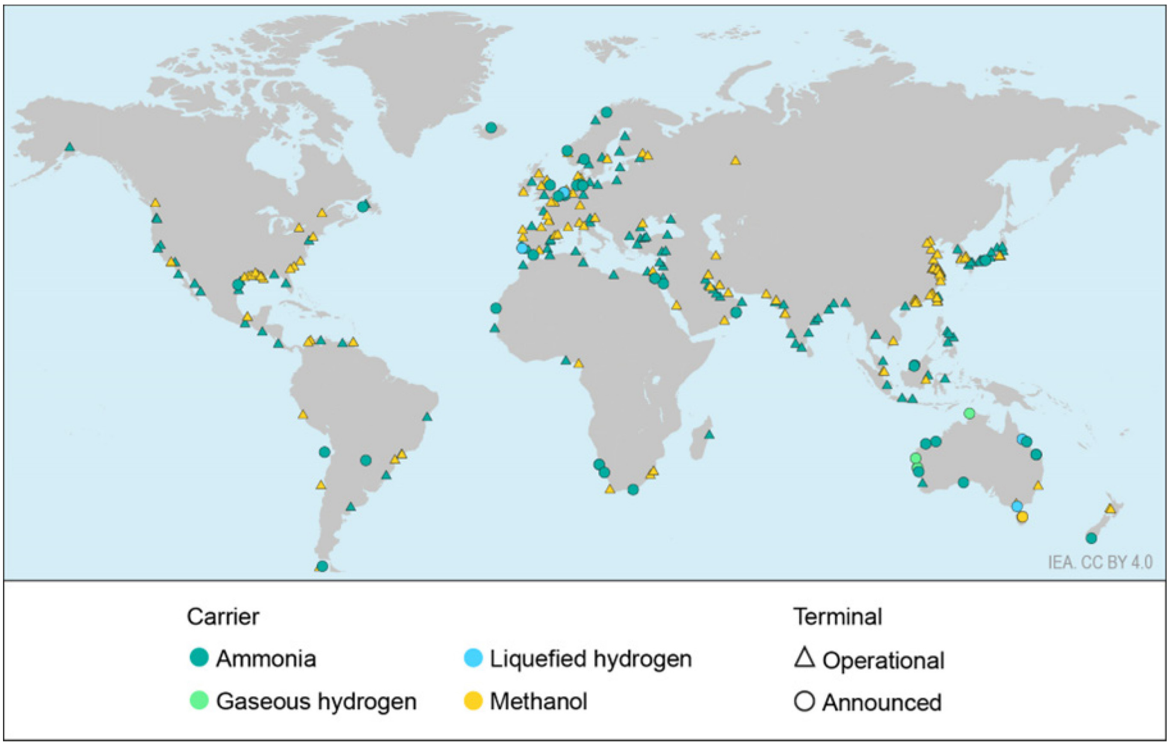
Infrastructure for shipping

For long distances of more than 2 500 km, the transport of hydrogen or hydrogen carriers by tanker can be a cost-effective option. In addition to the ships, this would require dedicated infrastructure at ports, including access to deep-water infrastructure and facilities to convert hydrogen into hydrogen carriers, in some cases at the exporting port, and, in some instances, facilities for reconversion back to hydrogen at the importing port. Hydrogen can be transported as ammonia, methanol or synthetic fuels, using an LOHC or in the form of liquefied hydrogen (LH_2).

Infrastructure at ports

Currently, export infrastructure for natural gas and ammonia, such as liquefaction plants, is mainly located in regions with abundant natural gas resources. In contrast, import infrastructure such as regasification plants is more widespread, due to there being more importing countries than exporting countries. Worldwide, there are more than 100 natural gas liquefaction plants in more than 40 ports and more than 160 natural gas regasification plants in nearly 150 ports. Approximately 150 terminals and ports can handle ammonia (Figure 4.8).

Figure 4.8 Existing and announced port infrastructure projects for hydrogen and hydrogen-based fuels trade



Notes: LOHC= liquid organic hydrogen carriers.

Almost 150 terminals for ammonia already exist and – while ammonia dominates the new project announcements – port facilities for other carriers are also being planned.

Although the existing ammonia infrastructure could already be used for hydrogen-based fuel trade, current global ammonia trade is around 20 Mt, equivalent to around 3.5 Mt H_2. This is well below the announced 12 Mt H_2 by 2030 for ammonia-based projects (Figure 4.1). Meeting this demand would require a tripling of existing ammonia trade infrastructure within this decade. While some capacity could be integrated into existing plants, potentially replacing fossil-based ammonia trading, or increasing annual plant utilisation with minor adjustments, realising the full potential of announced trade projects would require significant expansion. In addition, countries with good renewable energy resources that have not previously played a role in energy or ammonia trade may begin to do so, requiring not only new ammonia storage tanks but also new deep-water ports and berthing facilities.

Some projects are exploring the possibility of exporting compressed or liquefied hydrogen, which will require novel infrastructure that is not yet commercially available. Bringing such innovations to scale in the near future will require significant innovation efforts. In addition, other trade projects are considering the use of alternative carriers, such as LOHCs or methanol, which could use the more abundant oil-related infrastructure in ports, thereby minimising investment requirements for new infrastructure.

Based on announced projects, around 50 terminals and port infrastructure for the trade of hydrogen and ammonia could be realised by the end of the decade. More than half are new ammonia export terminals, of which more than ten could be located in Australia. In Europe, particularly in the Netherlands, Belgium and Germany, several ammonia import terminals have been announced. In the port of Rotterdam, OCI reached FID for the expansion of its existing ammonia terminal (June 2022) and it is assessing the feasibility of building a new storage tank, Gunvor contracted McDermott for the Front-End Engineering Design (FEED) of a new ammonia import terminal (September 2022), and other new ammonia import terminals under consideration in the port are ACE Terminal and Koole Terminals. Some liquefied natural gas (LNG) regasification terminals have announced their interest in importing synthetic methane. In July 2023, the European Union approved EUR 40 million support for a land-based LNG terminal in Brunsbüttel (Germany), to replace the current floating one, on the condition that the terminal be converted to import renewable energy carriers by 2043 at the latest. A detailed list of low-emission hydrogen infrastructure projects at ports can be found in the IEA Hydrogen Infrastructure Database.[66]

In addition to related port infrastructure, several large-scale ammonia cracking projects have been announced, although the technology is not yet proven on a commercial scale. Facilities are being considered in Wilhelmshaven, Rostock and Brunsbüttel (Germany), in the port of Antwerp (Belgium), in the ports of Liverpool

[66] For release in October 2023.

and Immigham (United Kingdom), as well as two facilities in the port of Rotterdam (Netherlands), which could crack ammonia to supply around 1.5 Mt H_2 by 2030.

Tankers for hydrogen transport

Existing tankers can carry low-emission hydrogen-based fuels and LOHCs, apart from LH_2. Ammonia, a gas at ambient temperature, requires liquefied gas tankers, while methanol, synthetic fuels and LOHCs, being liquids, can be shipped in chemical (including dedicated methanol tankers) or oil product tankers. Currently, around 40 tankers exclusively transport ammonia, along with up to 200 gas tankers capable of carrying ammonia. However, meeting the potential tripling of ammonia trade in this decade would require a significant increase in the number of gas tankers. This may be hampered by the relative technical complexity of liquefied gas tankers, with only few shipbuilding yards in Korea, Japan and China building these tankers. This could potentially create bottlenecks in the short term. In addition, addressing maritime decarbonisation remains a challenge for all tankers, as the carbon intensity of low-emission hydrogen must account for emissions from possible transport. In 2016, the first dual-fuel methanol tankers that can run on their methanol cargo were introduced, and by early 2023, there were 23 dual-fuel methanol tankers. Existing fleets can potentially be adapted for low-emission marine fuels, contingent on the space needed for new tanks and additional equipment. The decarbonisation of ammonia, chemical and product tankers must progress in parallel with the growth of low-emission hydrogen trade.

There are currently no commercially available tankers for shipping liquefied hydrogen. The Suiso Frontier, with a capacity of 1 250 m^3 (~75 tonnes [t] of LH_2), was the only demonstration project, with an LH_2 shipment from Australia to Japan in 2022. However, a valve malfunction in the gas combustion unit for hydrogen boil-off resulted in a fire while the ship was berthed in Australia. Lessons learned from this incident will be incorporated into a new design of the gas combustion unit for a larger 20 000 m^3 tanker (~1 200 t LH_2). Given the critical aspect of dealing with hydrogen boil-off gas, Shell signed an MoU with Alfa Laval in December 2022 to develop a gas combustion unit for excess hydrogen boil-off. Several companies are developing liquefied hydrogen tankers, expected to be operational by 2030, with a hydrogen cargo capacity of up to 160 000 m^3 (~9 600 t LH_2) (Table 4.5). In addition, efforts to use hydrogen to power ships may have positive spill-over effects, as the technologies could be applied to LH_2 tankers to allow part of the cargo to be used as fuel.

Compressed hydrogen shipping is being considered alongside liquefied hydrogen as an option for shipping hydrogen, particularly at smaller scales. In December 2022, Provaris Energy (Australia) received design Approval in Principle from the American Bureau of Shipping (ABS) for a 26 000 m^3 (250 bar, 430 t H_2) hydrogen tanker called H2Neo, with first units expected by 2026, and is developing a larger 120 000 m^3 tanker, H2Max (2 000 t H_2). In the German OffsH2ore project, Kongstein has developed a concept for a compressed hydrogen tanker for the offshore wind industry. Hydrogen produced offshore could be compressed to 500 bar, loaded onto a 400-tonne H_2-tanker and shipped to shore.

Table 4.5 Announced designs for liquefied hydrogen tankers expected to be commercial before 2030

Company	H_2 cargo containment	Country	Approval in principle*	Volume (m^3)
Korea Shipbuilding & Offshore Engineering (KSOE), Hyundai Mipo Dockyard	Spherical	Korea	Korean Register of Shipping (KRS)	20 000
Samsung Heavy Industries	Type C	Korea	ABS	20 000
Houlder, Shell, CB&I	Spherical	United Kingdom	DNV (H_2 containment)	20 000
C-Job Naval Architects, LH_2 Europe	Spherical	Netherlands	-	37 500
TotalEnergies, GTT, LMG Marin, Bureau Veritas	Membrane	France	Expected from Bureau Veritas	150 000
Kawasaki Heavy Industries (KHI)	Spherical (technological development completed)	Japan	Nippon Kaiji Kyokai (ClassNK)	160 000
Samsung Heavy Industries	Membrane	Korea	Lloyd's Register	160 000

* An Approval in Principle is an independent assessment of conceptual and innovative shipbuilding within an agreed framework, confirming that the ship design is feasible and that no significant obstacles exist to prevent the concept from being realised.
Note: m^3 = cubic metre.

Carbon intensity of hydrogen transport

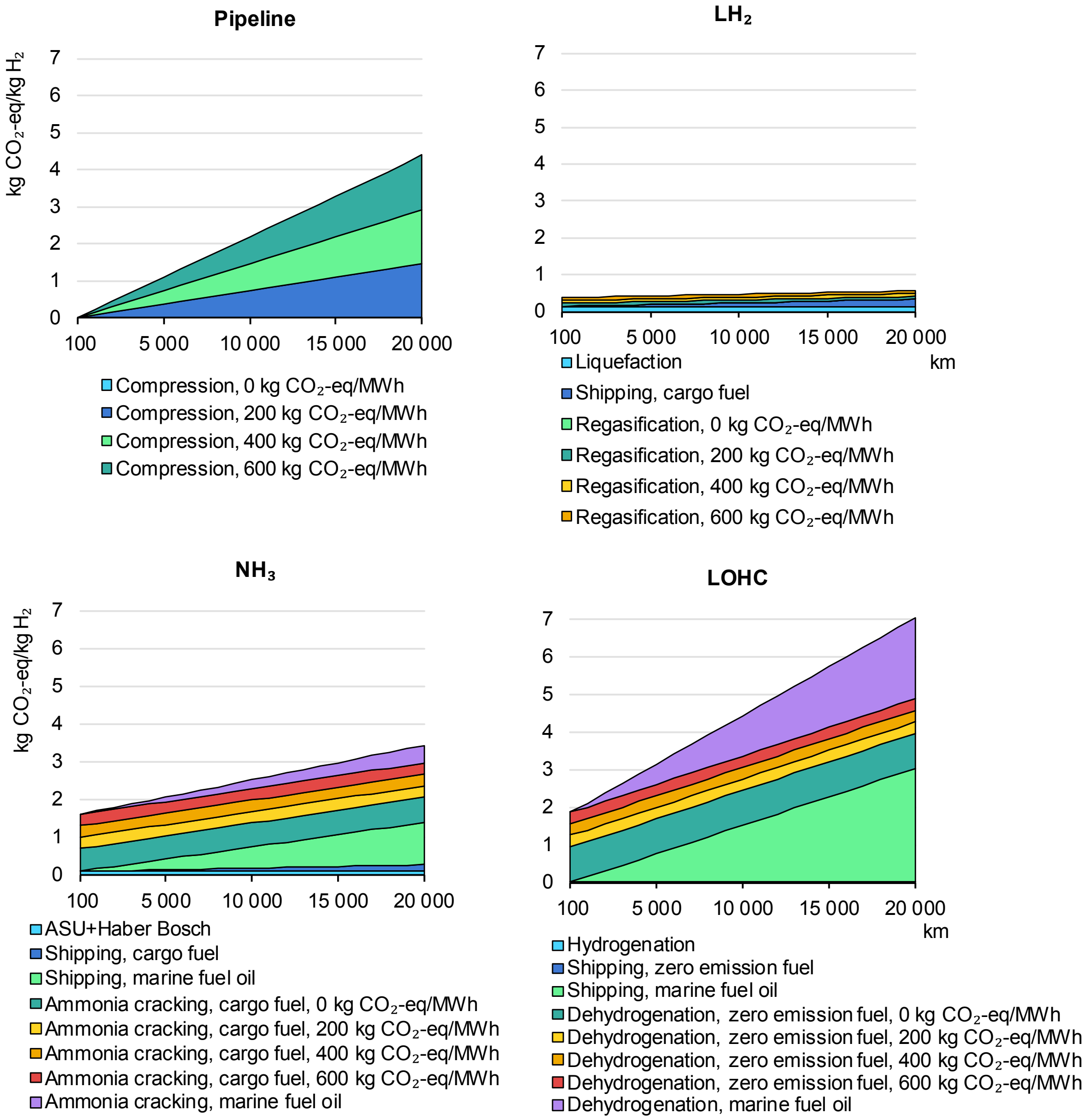
The complexities of transporting low-emission hydrogen over long distances may result in a potentially higher carbon footprint compared to natural gas, if the energy inputs required to transport hydrogen are not decarbonised.

Emissions from hydrogen transmission by pipeline depend on the electricity used for compression, and emission factors are likely to be lower when compression takes place near the production site, as low-emission electricity should already be available when producing electrolytic hydrogen, for example. However, if the pipeline crosses different regions and countries, low-emission electricity may not always be available along the pipeline route, so the electricity used for intermediate compression stages may significantly increase the emissions for hydrogen transport. Using, for example, electricity with an emission factor of 540 g CO_2-eq/kWh (world average emission factor for natural gas-based electricity generation, including upstream emissions) to compress hydrogen for 5 000 km in a 48-inch pipeline (operating at 100% of its design capacity) would result in emissions of 1 kg CO_2-eq/kg H_2. Alternatively, compressors may be powered by hydrogen from the pipeline, i.e. driven by hydrogen turbines instead of electrical motors, minimising the emissions associated with transmission to those associated with the low-emission hydrogen used for compression.

For long-distance transport, hydrogen can be converted into a denser form, either by liquefaction or conversion into a more easily transportable chemical carrier, such as ammonia or an LOHC. The transport of hydrogen via tanker can lead to two types of emissions: emissions from converting hydrogen into hydrogen carriers as well as reconverting it back into hydrogen, and emissions from the fuel used by the tanker (Figure 4.9).

If hydrogen is liquefied, most of the energy is consumed at the point of export, and in the case of electrolytic hydrogen, this means it could potentially have access to low-emission electricity, unless the export port is far away from the production site. However, if hydrogen is transported as a chemical carrier (ammonia or LOHC), its reconversion to pure hydrogen (if required) would result in significant energy consumption at the import location. If ammonia cracking and LOHC dehydrogenation processes use some of the low-emission hydrogen being transported to meet their heat requirements, the resulting emissions depend on the emissions associated with the low-emission hydrogen transported and the electricity consumption at the facility. For example, if hydrogen with an emission intensity of 1 kg CO_2-eq/kg H_2 is transported (using zero-emission marine fuel), the impact of ammonia cracking and LOHC dehydrogenation would be slightly less than 1 kg CO_2-eq/kg H_2 in addition to the emissions associated with production. However, if the emission factor for electricity is 600 g CO_2-eq/kWh, the emissions associated with the reconversion to hydrogen could rise to 2 kg CO_2-eq/kg H_2.

Figure 4.9 Emissions of hydrogen transport by pipeline and tanker depending on the distance and the grid emission factor of the importing region



Notes: ASU = air separation unit; LH_2 = liquefied hydrogen; LOHC = liquid organic hydrogen carrier; MWh = megawatt-hour; NH_3 = ammonia. The illustrative analysis is based on an emission intensity of hydrogen production of 1 kg CO_2-eq/kg H_2, an emission intensity of electricity of 20 kg CO_2-eq/MWh at the export port and different grid emission factors at the importing location. Illustrated values are cumulative, e.g. if the importing region has a grid emission factor of 400 kg CO_2-eq/MWh, those areas below that value (0 and 200 kg CO_2-eq/MWh) should also be considered. Hydrogen transport by pipeline assumes a 48-inch pipeline used at 100% of its nominal capacity. Cargo fuel refers to using the shipped cargo as fuel in the case of LH_2 and ammonia. Zero-emission fuel represents a shipping fuel with zero direct greenhouse gas emissions. For the use of marine fuel oil, the direct emissions are included, but not any upstream and midstream emissions related to oil production and refining. Emissions include conditioning, i.e. the conversion of hydrogen into other carriers at the export port and the reconversion back into hydrogen at the import port. Ammonia cracking is assumed to burn imported ammonia to provide process heat, while LOHC dehydrogenation is assumed to use dehydrogenated hydrogen for process heat. The areas "Ammonia cracking, marine fuel oil" and "Dehydrogenation, marine fuel oil" illustrate the emissions associated with the transport of the fuel by ship, i.e. ammonia or dehydrogenated hydrogen used to provide process heat for the ammonia cracking and LOHC dehydrogenation processes, respectively, without being delivered to the consumer. Emissions from unburned boil-off hydrogen or fugitive emissions of hydrogen are not considered.

Hydrogen transport can have a significant carbon footprint, and the maritime sector is not yet decarbonised, especially with regards to lower density shipping technologies.

The emissions from the tanker transport will depend on the fuel used for the voyage. If LH_2 is used as a marine fuel, the associated emissions would remain small and proportional to the emissions associated with the production of the transported hydrogen, the transport distance, the amount of unburned boil-off hydrogen and other fugitive emissions. Shipping hydrogen in tankers that do not use low-emission fuels, particularly using marine fuel oil, would result in a high carbon footprint. For instance, shipping ammonia or LOHC over 15 000 km would result in emissions of 1.2 kg CO_2-eq/kg H_2 or 3.9 kg CO_2-eq/kg H_2, respectively. These emissions take into consideration that some of the hydrogen is used internally in the reconversion process, i.e. it is transported to the import port but will not be delivered to a final consumer.

As the emissions associated with imported hydrogen increase as marine fuel oil is consumed during the voyage, the emissions from the use of that ammonia/hydrogen in the ammonia cracking or LOHC dehydrogenation process also increase, adding to the total emissions associated to shipping.

Ensuring the decarbonisation of tanker transport itself is therefore crucial to enable the delivery of low-emission hydrogen over long distances without significantly increasing the carbon footprint, and may pose a challenge for compliance with regulatory frameworks with well-to-point of delivery (or well-to-tank) and well-to-wheel system boundaries, such as the 3.4 kg CO_2-eq/kg H_2 of the EU Renewable Energy Directive II. With hydrogen being an indirect GHG, it is also important to better understand and account for potential leakages along the hydrogen supply chain, including storage, loading/unloading and transport (Box 4.3).

Box 4.3 Hydrogen leakage monitoring

Hydrogen is not a direct GHG, but it interacts with other compounds in the atmosphere, affecting the concentration of the GHGs methane, tropospheric ozone and stratospheric water vapour. While hydrogen does not have an Intergovernmental Panel on Climate Change (IPCC)-defined global warming potential (GWP), the latest scientific estimates suggest that hydrogen could have a GWP over a 100-year time horizon of 11.6 ± 2.8 kg CO_2-eq/kg H_2. Hydrogen has a short atmospheric lifetime, and estimates suggest that its global warming potential over a 20-year horizon would be more than three times higher than its 100-year impact. Given hydrogen's small molecule size, high diffusivity and low viscosity, leakage can occur throughout its value chain, with transport and storage posing higher risks. However, quantitative information on hydrogen leakage remains limited. Mitigating potential climate impacts will require further research to develop technologies and operational practices that minimise leaks, as well as robust leak detection and repair mechanisms.

To assess hydrogen leakage, new regulations must prioritise detection and monitoring, particularly in transport and storage. However, partly due to a lack of such regulation, only a few technologies exist for hydrogen leakage detection. These are currently insufficient as they focus on identifying large, potentially explosive leaks for safety reasons, and lack the speed and sensitivity to measure smaller leaks. Despite the lack of commercially available technology, several projects are underway:

- In March 2023, US company Aerodyne Research, in collaboration with the Environmental Defence Fund and with funding from the DOE's Small Business Innovation Research Program, unveiled a hydrogen sensor using laser spectroscopy capable of detecting leaks as low as 10 ppb within a second. However, the sensor remains expensive (estimated at around USD 100 000 per sensor, compared to devices for methane that can cost a few thousand dollars) and has not yet reached commercialisation.
- In March 2023, US company NETL was granted a patent for an optic hydrogen sensor capable of measuring hydrogen at underground storage facilities at the ppm level, utilising multiple sensing points.
- In 2023, the US DOE announced USD 2.2 million funding for improving the understanding of hydrogen as an indirect GHG and USD 8.6 million for R&D activities to develop ppb-level hydrogen sensors.
- In January 2023, the Green2TSO-OPTHYCS project started, with a EUR 2.5 million grant from the EU Horizon Clean Hydrogen Joint Undertaking programme, led by Spanish Enagás. The project aims to develop new optical fibre sensors for continuous hydrogen leak detection in production, transport and storage processes.

Chapter 5. Investment, finance and innovation

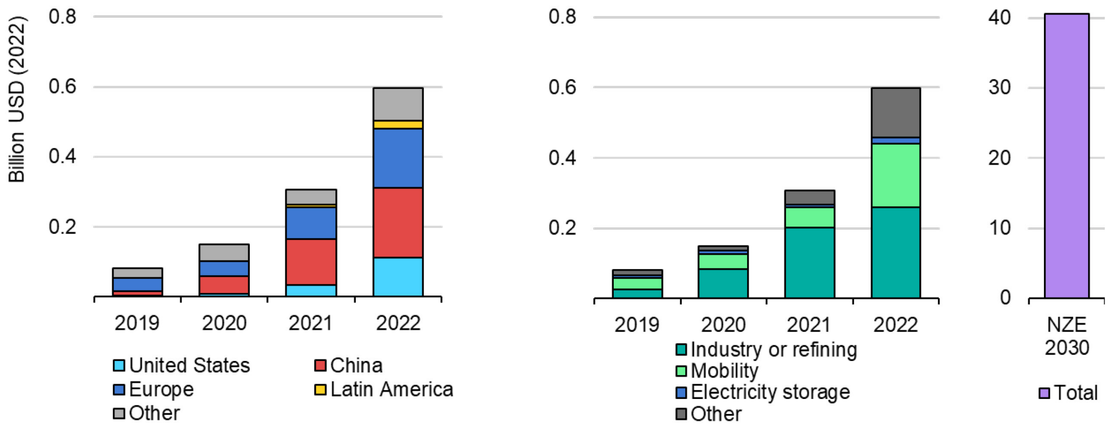
Investments in the hydrogen sector

Investment in projects in operation and under construction

Government policies and the plans of project developers are translating into an expanding flow of capital into the low-emission hydrogen sector. Based on projects in operation and construction, we estimate that spending on electrolyser installations hit a new record in 2022, at USD 0.6 billion globally, double the 2021 value (Figure 5.1). An additional USD 0.5 billion was spent in 2022 on projects under construction to produce low-emission hydrogen with carbon capture, utilisation and storage (CCUS). Reaching the USD 41 billion of spending on electrolyser installations in 2030 envisaged in the Net Zero Emissions by 2050 Scenario (NZE Scenario) would require 70% annual investment growth for the remainder of this decade.

Since 2021, investment in hydrogen production has been dominated by a relatively small number of very large projects. Several final investment decisions (FIDs) in 2022 mobilised an unprecedented level of spending, even though the capacity that entered operation in 2022 was lower than in 2021, when a single, very large 150 MW installation started operation. Among these FIDs, the largest were for the 2 GW NEOM Green Hydrogen project in Saudi Arabia and 320 MW Green Hydrogen and Green Ammonia project in Oman, both aiming to produce ammonia for exports from 2026. These were followed by a 260 MW facility at a refinery in Xinjiang, China, which entered operation in June 2023 and sets a new benchmark for the scale of an operational plant. Another 80 MW project in China was commissioned in June 2023 for use in a coal-to-chemicals facility. In Europe, Shell's Holland Hydrogen I in the Netherlands (200 MW) will have a capacity ten times that of Europe's largest existing plant, and is aiming to supply an existing refinery by 2025. In Sweden, H2 Green Steel drew closer to an FID for an electrolyser of over 700 MW and a new steel production plant: it has secured EUR 3.5 billion (~USD 3.7 billion) of debt and EUR 1.8 billion (~USD 1.9 billion) of equity since 2022.

Figure 5.1. Investment in electrolyser installations by region (left) and intended use (right), and Net Zero Emissions by 2050 Scenario requirements, 2019-2030



Notes: NZE = Net Zero Emissions by 2050 Scenario. 2022 values are estimated annualised spending on projects that are under construction and due to enter operation in 2023. Estimates are based on capital cost assumptions and announced capacities of electricity input or hydrogen output volumes per project, and include electrolysers for hydrogen supply used for energy purposes or as an alternative to fossil fuel use in industry (such as chemical production and oil refining). "Mobility" includes projects for which the hydrogen output is intended for use in vehicles; hydrogen intended for conversion to hydrogen-based fuels is included in "Other". These estimates supersede those published in IEA World Energy Investment 2023.

Investment in electrolysers is growing fast, but would require 70% annual growth until 2030 to get on track with the NZE Scenario.

Two projects for producing hydrogen from natural gas equipped with CCUS also took FIDs in 2022. Together, their hydrogen capacity will be three times larger than all the installed electrolysers in the world today. In the United States, financial close was reached in February 2023 on a facility in Texas to produce 0.2 Mt of hydrogen for fertiliser production from 2025, with over 90% of the CO_2 captured and sent to dedicated geological storage. The capacity is equivalent to around 0.8 GW of electrolysis running 90% of the time. A hydrogen energy complex is under construction in Canada to produce around 0.15 Mt of hydrogen from 2024 to be used in refining, petrochemicals, transportation and power generation, with 95% of the CO_2 captured and sent to dedicated geological storage. The capacity is equivalent to 0.6 GW of electrolysis running 90% of the time. It has grant funding from the Federal and a provincial government (Alberta). While several similar projects are well advanced in Europe and the Middle East, the more favourable investment environment in North America has made it the leader in hydrogen production with CCUS.

As spending on these electrolysis- and CCUS-related hydrogen projects flows along the value chain to suppliers and contractors, the total market size for low-emission hydrogen is expanding accordingly (Box 5.1).

Box 5.1 Sizing the global market for low-emission hydrogen

As demand for low-emission hydrogen and hydrogen-based fuels grows, annual capital investments in projects will converge towards total spending in the value chains of these projects. Money that stems from hardware purchases and installation contracts will flow to suppliers and fund their procurement of inputs. The sum of these sales represents the market value of the hydrogen and hydrogen-based fuels sector. In 2022, the USD 1 billion spent on projects to produce low-emission hydrogen in the same year may not have perfectly matched the full market value of the sector because some outlay on equipment and component factories must precede project spending. By 2030, however, project spending on production, transport and conversion to hydrogen-based fuels should be a reliable proxy for market size. In 2030 in the Stated Policies Scenario (STEPS), market size rises to USD 12 billion, equivalent to the spending on offshore wind in Europe in 2022. In the NZE Scenario, it rises much more quickly, to USD 117 billion, roughly the size of the market for rooftop solar PV installations in the Asia-Pacific region in 2022.

Billion USD (2022)	2022	2030	
		STEPS	NZE
Electrolysis installations	0.7	4.7	41
CCUS-equipped plants	0.5	0.6	16
Infrastructure	0.2	5.5	36
Hydrogen-based fuels production	0	2.0	25
Total	1.4	12	117
Equivalent part of the energy sector in 2022	LNG infrastructure in Africa and Europe	Offshore wind in Europe	Rooftop solar PV installations in Asia-Pacific

Notes: LNG = Liquefied natural gas; NZE = Net Zero Emissions by 2050 Scenario; STEPS = Stated Policies Scenario.

It is more challenging to project the total market value of the hydrogen and hydrogen-based fuels produced from installed assets in 2030 for several reasons. Production costs in 2030 will depend to a large extent on uncertain electricity costs for electrolyser operators, or fuel and CO_2 prices for operators of CCUS-equipped plants. The share of these costs that is borne by taxpayers and consumers will depend on policy decisions that are not yet fully formulated. Finally, costs may bear little relationship to low-emission hydrogen prices, for which the means of market discovery remain highly speculative. In some sectors, hydrogen prices may be pegged to the price of the fuel they substitute, such as natural gas or diesel. Where long-term contracts are available, such as those underwritten by governments, prices may follow levelised costs plus the cost of hydrogen transport, storage and a profit margin. In other situations, prices may reflect the prices of low-emission alternatives, such as bioenergy, direct electrification or low-emission fuel imports. For hydrogen-based fuels, prices for meeting target shares of sustainable aviation and maritime fuels may be set by the marginal international production cost.

These alternatives could lead to wide differences: if the average global price for delivered hydrogen (including transport, storage and distribution) were USD 3/kg in 2030, the total market value in the NZE Scenario would be USD 200 billion; if it were USD 7.5 per kg in 2030, this would rise to USD 500 billion.

Policy support for new investments

Looking ahead, additional large FIDs are widely expected in Europe and North America as a result of major policy initiatives and associated funding, which have been strengthened due to the ongoing energy crisis and regional ambitions to secure value chains. The biggest boost to investment is likely to stem from the 2022 US Inflation Reduction Act, coupled with the Hydrogen Hubs initiative launched in 2021 and an expansion of the budget of the Loans Programme Office. The pay-for-performance approach and magnitude of the tax credit system compared to project-based funding competitions has led to speculation that the Act might lead to the relocation of projects to the United States, especially electrolyser and component factories. This concern was partly fuelled by uncertainty about the environmental requirements for hydrogen to qualify for EU incentives, which has since been mostly resolved. While many new US projects have recently been announced, there is only anecdotal evidence to date that these developers' other projects outside the United States no longer have their full commitment. More clarity is expected by the end of 2023, when the environmental requirements to qualify for US tax credits are likely to be finalised.

Among support measures in the European Union, the most notable is the establishment in March 2023 of the European Hydrogen Bank, a European Commission funding instrument. Its initial mandate will be "reverse auctions" that award funding from the existing Innovation Fund to the lowest bidders for support per unit of hydrogen meeting the European Union's environmental criteria. The budget for the first auction will be EUR 800 million (~USD 842 million). The European Commission is exploring whether it could also carve out a budget to help potential external exporters of hydrogen into the European Union, as well as to support electrolyser manufacturers. This would complement support from member states via the Important Projects of Common European Interest (IPCEI) provisions, approved in 2022. Also in Europe, the United Kingdom's March 2023 budget promised GBP 20 billion (~USD 25 billion) over 20 years to CCUS-equipped facilities, and 408 MW of electrolysis projects were shortlisted in March 2023 as part of GBP 240 million (~USD 296 million) available funding.

Several investments have been made into hydrogen-related infrastructure. These include an FID by fertiliser company OCI to expand by 200% its 0.4 Mt ammonia import terminal in the Netherlands by the end of 2023. Also in the Netherlands, Dutch gas transmission operator Gasunie took an FID for more than USD 110 million into 30 km of hydrogen pipeline to be operational by 2025.

Some concerns have been raised that the substantial public funding available for hydrogen-related investments in Europe and North America might place projects in emerging markets and developing economies (EMDEs) at a disadvantage. This is because, in some cases, project developers might prioritise projects in locations where public support leads to the highest profits. Some developers may also seek to establish and ensure access to domestic value chains, for example in light of the US Inflation Reduction Act incentives. However, there are also reasons to believe that this need not preclude investment elsewhere. Unlike for other energy technologies, the US hydrogen tax credits have no local content requirements, and hydrogen incentives proposed by the EU Net Zero Industry Act are not highly restrictive in this regard. In addition, a range of multilateral and bilateral sources of funds have been announced since 2022 to address fundamental investment challenges in EMDEs (see below). Instruments such as the German H2Global programme have been designed to offer stable contracts for purchase of low-emission hydrogen from overseas.

Cost inflation for new low-emission hydrogen projects

Inflation has gripped the global economy since 2022, significantly increasing the prices of equipment and interest rates on loans. Within the energy sector, these factors particularly raise costs for developers of capital-intensive energy supplies such as those from renewable electricity generation, batteries or electrolysis hydrogen. Some hydrogen projects with feasibility studies that were conducted before mid-2022 have had to rework their cost estimates and re-evaluate their financial plans to accommodate cost increases of more than 50%. While most intense in Europe and least consequential in China, cost inflation is depressing investment activity around the world. It increases the gap between available public support and production costs, it means that public funds cannot be shared across as many projects and it creates a much larger financial package to be financed for each project. However, this recent reversal in the trend towards lower costs for low-emission hydrogen plants is not expected to be permanent and, with costs rising more slowly now, the main impact may be delays to FIDs rather than cancellations.

There are several different sources of cost inflation:

- higher equipment costs
- higher labour costs for installation and operation
- higher interest rates for debt (also known as the cost of capital)
- more competition to work with a small number of engineering, procurement, and construction (EPC) contractors that can offer guarantees that enable borrowing at a lower cost of capital
- higher fuel and electricity prices.

For electrolyser installations, the impacts of these factors can be especially harmful (Figure 5.2). Like renewable electricity plants, such as solar PV and wind, electrolyser costs are largely borne upfront, with low operational costs after construction if dedicated renewable electricity capacity is installed to supply the electrolyser. An increase in the cost of capital from, for example, 5% to 8% (in line with a 3 percentage-point rise in risk-free rates), raises today's project cost by nearly one-third. However, electrolyser installation and operation are unlike those for solar PV due to the need for pipework, pressurised equipment, specialist gas handling expertise, interfaces between electrical, chemical and moving parts and other elements that require sophisticated engineering.[67] The higher labour inputs for electrolyser installations have meant higher recent cost increases compared with solar PV, for example.

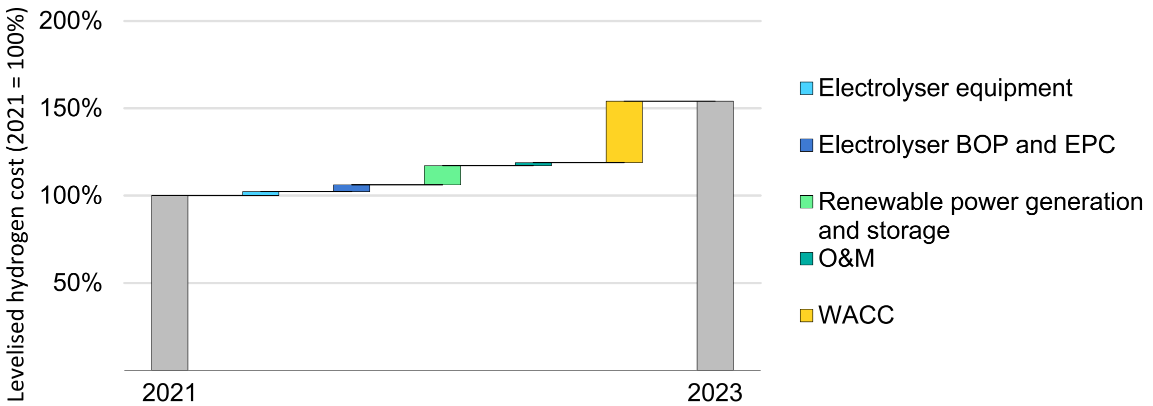
These cost increases exacerbate an existing tension in the sector caused by a disconnect between policy targets, cost expectations and the status of manufacturing today, especially in Europe and North America. In many cases, prospective buyers of electrolysers ask for prices that reflect the anticipated costs of an established, mass-manufactured electrolyser sector. Such prices are often needed to meet investors' required rates of returns, given the magnitude of public incentives available. However, with considerable competition between suppliers of promising electrolyser technologies, some are not yet manufacturing their most efficient designs at sufficient scale to meet buyers' cost expectations. Furthermore, they are unable to provide standard industry performance guarantees as the experience is not yet available. Without such guarantees, the cost of capital for a project is higher.

Cost increases for hydrogen production projects have coincided with a relaxation of natural gas prices, particularly in Europe. Spot gas prices across north-east Asian, North American and European markets dropped by close to 60% between mid-December 2022 and the end of the first quarter of 2023. While low-emission

[67] While it is foreseeable that some of the onsite complexity of installation could be reduced in future with integrated and standardised equipment packages, these so-called "balance of plant" costs will remain higher than for purely electrical systems and higher operations and maintenance costs can likewise not be eliminated.

hydrogen competes with natural gas in all potential applications, in existing hydrogen applications it often competes with hydrogen from unabated reforming of natural gas. The brief window in which some hydrogen projects had claimed cost parity between their proposed hydrogen production and spot natural gas prices has closed for now, though low-emission hydrogen costs below those for hydrogen from unabated fossil fuels may still be realised in coming years in regions relying on LNG imports for natural gas.

Figure 5.2. Factors that could contribute to cost inflation for an electrolyser installation since 2021



Notes: BOP = balance of plant; EPC = engineering, procurement and construction; O&M = operational expenditures and maintenance costs; WACC = weighted average cost of capital.
Sources: IEA analysis based on input from McKinsey & Company, the Hydrogen Council and various company contacts.

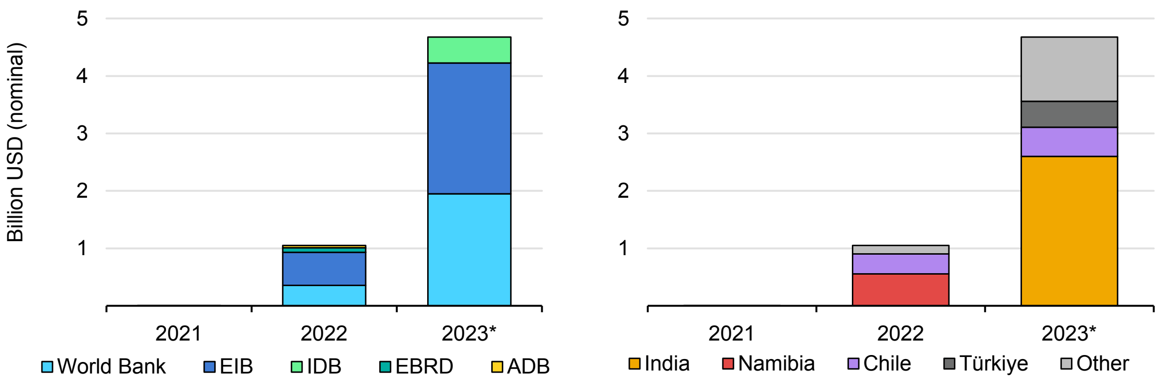
Rising costs due to inflation, particularly an increase in the cost of capital, are having a strong impact on the costs of hydrogen production from proposed electrolysis projects.

Multilateral financial commitments are growing

Multilateral development banks stepped up their financial commitments in the area of hydrogen in 2022 and so far this has continued apace in 2023 (Figure 5.3). Nine-tenths of the funds have been made available as loans to governments of EMDEs. This money can be used for project feasibility studies, capacity building and support to project developers. A much smaller share, less than 1%, has been committed as technical assistance grants or project equity. Among funders, the European Investment Bank (EIB) and World Bank have made the largest commitments, notably to India, Brazil and Chile. Moreover, the World Bank Group launched in November 2022 a Hydrogen for Development Partnership (H4D) to foster capacity building and regulatory solutions, business models, and technologies towards the rollout of low-emission hydrogen in developing countries.

Multilateral finance can assist the implementation of hydrogen strategies in countries that have fewer resources to invest in this area. In particular, some of the finance has been directed to countries that are exploring opportunities to export hydrogen. For example, the EIB has committed around USD 1 billion from EU countries – some of which could become hydrogen importers – to Brazil, and over USD 0.5 billion to Namibia. It has also committed more than USD 1 billion to India.

Figure 5.3. Financial commitments to hydrogen by multilateral development banks, by source and partner country, by year of announcement, 2021-2023*



Notes: 2023* = year to July 2023 only; EIB = European Investment Bank; IDB = Inter-American Development Bank; EBRD = European Bank for Reconstruction and Development; ADB = Asian Development Bank; Türkyie = Republic of Türkiye.

Multilateral development banks are increasing financial commitments with EMDEs in the area of hydrogen.

There has also been an increase in bilateral financial commitments between governments. Among the most active bilateral financiers is the German development bank KfW, which has created a credit fund for hydrogen development projects in EMDEs, and allocated USD 100 million to Chile in 2023. In June 2023, Invest International, an agency of the Dutch government, granted USD 44 million to create a fund for hydrogen projects in Namibia and USD 50 million to a similar initiative in South Africa.

Financial performance of hydrogen firms

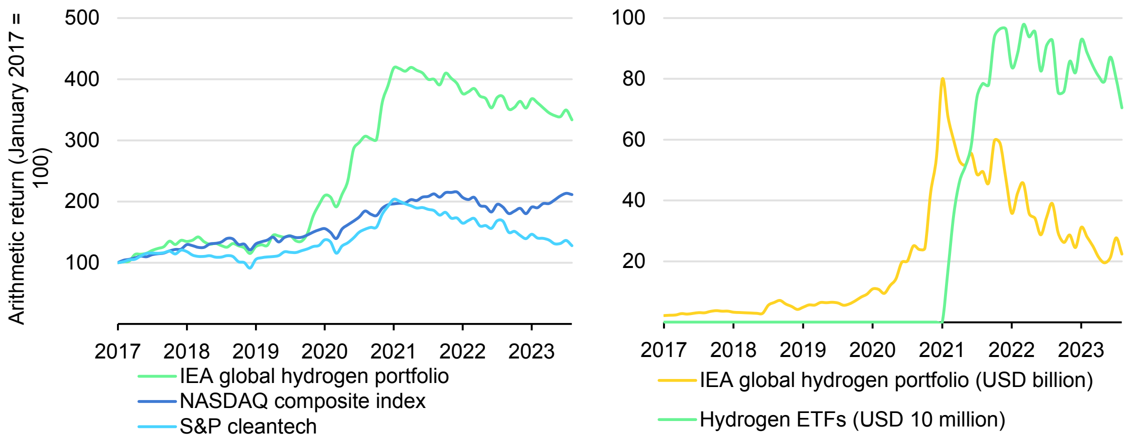
Unprecedented levels of investment in hydrogen companies have been mobilised as near-term expectations for hydrogen projects have risen. To track this trend, we assembled a portfolio of publicly traded companies whose success depends on demand for low-emission hydrogen growing.[68] These companies span a range

[68] To try to be as representative as possible the portfolio has been expanded from 33 to 43 members since the Global Hydrogen Review 2022.

of sectors, including electrolyser and fuel cell manufacturing, low-emission hydrogen and ammonia project development, hydrogen distribution infrastructure and hydrogen-fuelled vehicles.

The total market capitalisation of the portfolio tracks some of the major clean energy trends since 2019: initial hopes for high growth were buoyed through the Covid-19 pandemic by expectations that governments would ensure a quick recovery, but rising interest rates in 2022 were compounded by the energy crisis and this led investors to withdraw equity from sectors struggling to meet shareholder requirements (Figure 5.4). By the end of August 2023, amid project and contract delays, the market capitalisation of the portfolio had dropped back to its level in July 2020. It would have been lower without the addition of thyssenkrupp nucera in July 2023 via market listing that raised over USD 3 billion. Meanwhile, while the monthly investor returns and revenues of this portfolio performed very strongly up to 2021 and remain almost three times higher than five years ago, they are now following the downward trend of more general cleantech indices rather than the recent uptick enjoyed by established and less hardware-intensive technology firms (as represented by the NASDAQ).

Figure 5.4. Monthly returns (left) and market capitalisation (right) of hydrogen companies, hydrogen funds and relevant benchmarks, 2017-2023



Notes: ETFs = exchange-traded funds; portfolio member tickers: 288620 KS, 336260 KS, 702 HK, ADN US, AFC LN, ALHAF FP, ALHRS FP, AMMPF US, BE US, BLDP CN, CASAL SW, CI SS, CPH2 LN, CWR LN, F3C GY, FCEL US, FHYD CN, GNCL IT, GREENH DC, H2O GY, HDF FP, HTOO US, HYON NO, HYPRO NO, HYSR US, HYZN US, HZR AU, IMPC SS, ITM LN, LHYFE FP, MCPHY FP, NCH2 GY, NEL NO, NHHH CV, NXH CN, PCELL SS, PHE LN, PLUG US, PPS LN, PV1 AU, SPN AU, TECO NO, VYDR US.

Source: IEA calculations based on Bloomberg (2023).

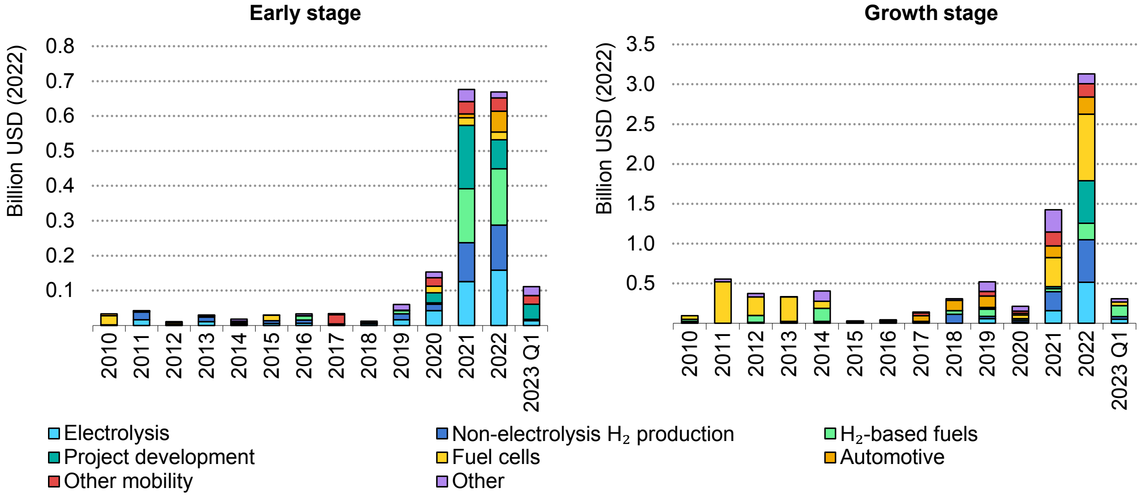
Since mid-2022, returns from a portfolio of 43 low-emission hydrogen firms have stabilised, but their market capitalisation has fallen in line with lower valuations for technology firms.

Even as the value of listed hydrogen companies has been adjusted downwards, publicly traded dedicated hydrogen funds have largely maintained their value. These funds are established to invest equity in a blend of private companies and projects that are scaling up low-emission hydrogen supply and use. Since 2022 these funds have shifted their attention towards projects, which they now expect to yield higher returns relative to technology companies in the medium term.

Venture capital investment

Start-ups working on hydrogen-related technologies and businesses raised record amounts of early- and growth-stage equity in 2022. At USD 670 million, early-stage deals[69] matched the outstanding performance in 2021, which was almost five times higher than in 2020 (Figure 5.5). Growth-stage funding, which requires more capital but funds less risky innovation, more than doubled to USD 3.1 billion. This is an even more impressive achievement in light of only a 1% increase overall in growth-stage equity funding for energy firms (to USD 34.4 billion). However, the macroeconomic conditions that have reduced the amount of capital available for venture investments across the global economy in 2023 are likely to affect growth-stage funding in particular, and this year's level is set to be lower than in 2022.

Figure 5.5. Venture capital investment in energy start-ups in hydrogen-related areas, for early-stage and growth-stage deals, 2010-2023



Notes: Early-stage deals are defined as seed and Series A deals; very large deals in these categories – above a value equal to the 90th percentile growth equity deals in that sector and year – are excluded and reclassified as growth-stage investments; "Other mobility" includes aviation and maritime; "Other" includes storage, other infrastructure and industrial applications.

Sources: IEA analysis based on Cleantech Group (2023) and Crunchbase (2023).

Hydrogen firms achieved higher venture capital fundraising growth than other sectors in 2022, but a wider slowdown in venture capital has dimmed prospects for continued growth in 2023.

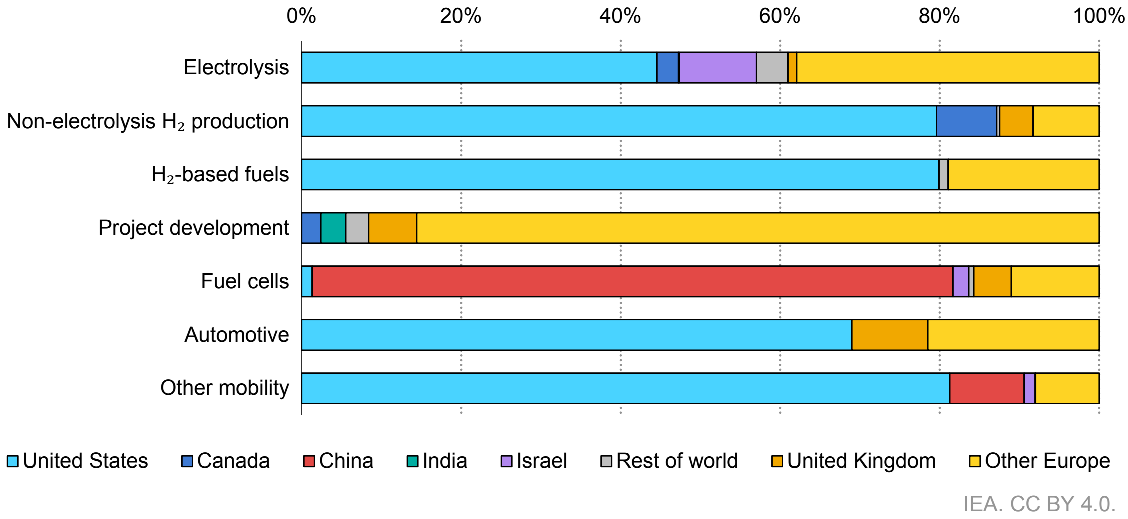
[69] Equity investments that provide funds to support entrepreneurs with technology testing and design in return for a stake in the start-up. These deals play a critical role in honing good ideas and adapting them to market opportunities.

Notable early-stage deals since mid-2022 included those for: Hysata, an Australian electrolyser developer raising USD 29 million; Hygenco, an Indian project developer raising USD 27 million; Levidian, a British developer of methane cracking raising USD 15 million; and Fabrum, a New Zealand designer of liquefaction equipment, raising USD 14 million. The largest growth-stage deal, at over USD 300 million, was for Monolith, a US developer of methane pyrolysis.

Start-ups in the United States have been the main recipients of venture capital deals in hydrogen-related technologies, apart from in two areas: fuel cells, an area in which Chinese start-ups have dominated fundraising; and project development, an area led by European start-ups (Figure 5.6).

As the size of hydrogen projects grows, the share of start-ups that are project developers, not technology owners, has risen. However, growth-stage investment and acquisitions still tend to favour technology owners. In an analysis of 391 start-ups founded since 1990 with activities related to hydrogen, 70% were found to hold at least one patent application. More than 80% of the growth-stage investment in hydrogen start-ups since 2000 was in companies that had already filed a patent application. Overall, 55% of all venture capital funding for hydrogen start-ups went to the 117 companies that had filed patent applications in the period 2011-2020.

Figure 5.6. Early- and growth-stage equity investment in energy start-ups in hydrogen-related areas by region, 2018-2022



Sources: IEA analysis based on Cleantech Group (2023) and Crunchbase (2023).

US hydrogen start-ups have been the main recipients of venture capital deals in all areas except for fuel cells (dominated by Chinese firms) and project development (by European firms).

Innovation in hydrogen technologies

Innovation in clean energy technologies needs to accelerate for hydrogen to play its role in the clean energy transition. The level of maturity of hydrogen-related technologies varies widely across the supply chain, with technologies for low-emission hydrogen supply much more developed than for end uses (except for established applications in refining and the chemical industry).

Technologies for the production of low-emission hydrogen are well developed and innovation continues to make major breakthroughs (Figure 5.7). Alkaline and proton exchange membrane (PEM) electrolysers are commercially available, but manufacturers have a strong innovation focus to keep decreasing equipment costs. Reducing critical material loads is a good example and this year H2U Technologies announced the development of a 200 kW iridium-free PEM electrolyser. Solid oxide electrolysers (SOEC), the most efficient electrolysis technology, are quickly approaching commercialisation. The two largest demonstration SOEC started operating in 2023, one by Sunfire (2.6 MW) and the other by Bloom Energy (4 MW). Anion exchange membrane (AEM) electrolysers are at an earlier stage of development, but the technology is also evolving rapidly and Enapter launched the world's first megawatt AEM electrolyser in May 2023. In addition, direct electrolysis of seawater was demonstrated for the first time in an offshore platform in China in June 2023. In August 2023 Hysata opened its new electrolyser manufacturing facility, where it will build a demonstrator (5 MW) of its advanced alkaline capillary-fed electrolyser – claiming up to 95% efficiency – with the view to reach commercial-scale units by 2025.

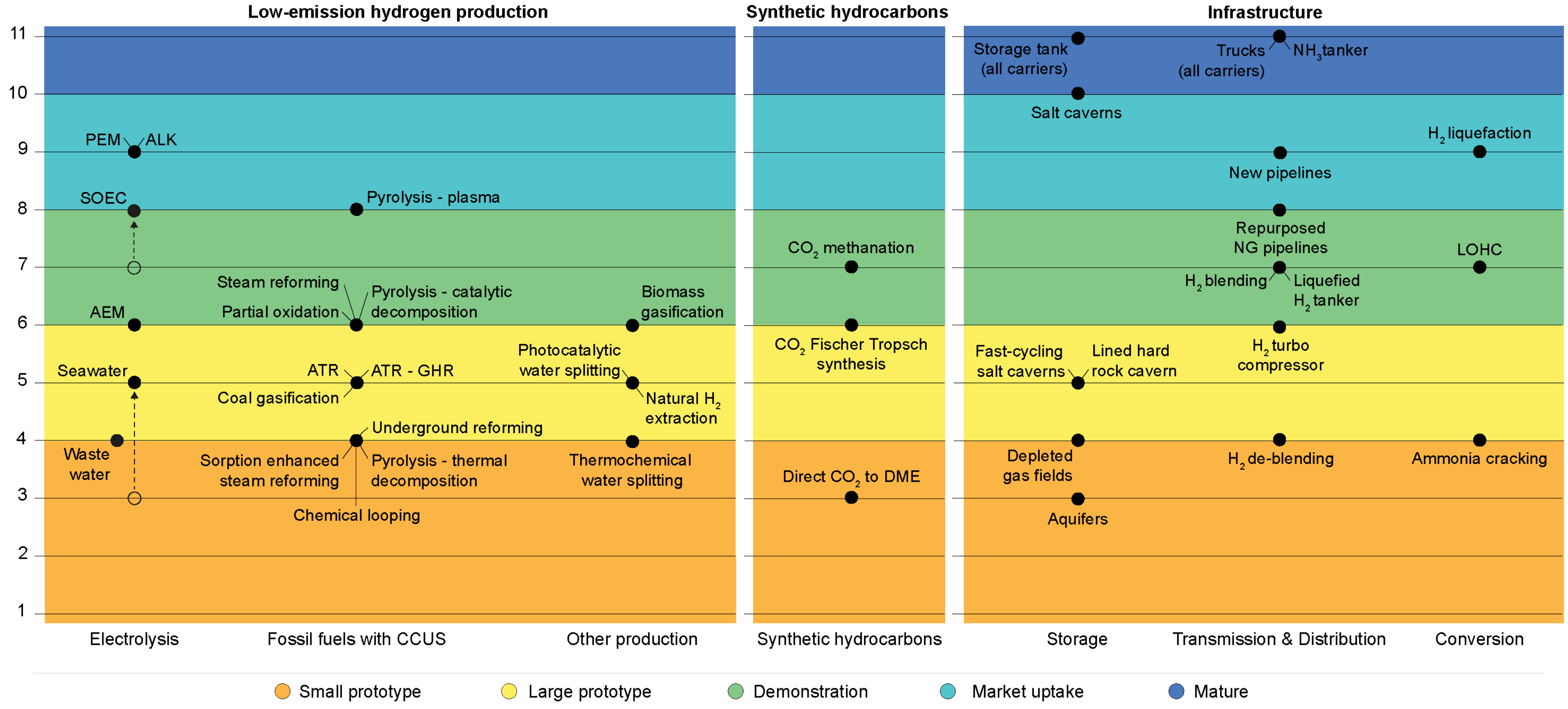
The production of low-emission hydrogen from natural gas with CCUS requires the achievement of very high CO_2 capture rates at plant level. This technology is set to be demonstrated at commercial scale for the first time soon, as two large projects have begun construction since the release of the Global Hydrogen Review 2022 (GHR 2022). These new plants are expected to become operational in 2024 and 2025, and are designed to produce low-emission hydrogen via autothermal reforming, which reduces the cost of raising capture rates above 90%. This will represent a significant improvement compared with existing CCUS-equipped hydrogen plants, which only capture around 60% of the CO_2 coming from a steam methane reformer (SMR). This lower level reflects the relative ease of capturing CO_2 from the natural gas used as a feedstock at an SMR, compared with the much higher cost of capturing the remaining 40% that comes from the combustion of natural gas to generate the heat required in the process. Meanwhile, Topsoe is pursuing innovations for the electrification of the heat for the SMR, which would eliminate the need to burn natural gas for the SMR and therefore only require capturing the feedstock-related CO_2. In 2022, Topsoe signed a EUR 45 million (~USD 47 million) loan agreement with the EIB specifically to support R&D investments in such early-stage hydrogen technologies.

Most technologies for hydrogen transport and storage are mature, although still at small scale. Innovation and demonstration efforts are underway to bring these technologies to the scale needed to facilitate the adoption of hydrogen as a clean energy vector. In April 2023, the world's first pure hydrogen storage facility in an underground porous reservoir started operation (~3 GWh of hydrogen).

In end-use technologies, the situation is different: the technologies in sectors in which emissions are hard to abate, where hydrogen is expected to play a more important role for decarbonisation, are much less mature and innovation is taking place at a slower pace (Figure 5.8). Nevertheless, there are some positive signs of progress, such as in industry, where RD&D in the use of hydrogen for high-temperature heat in ancillary processes moved forward last year. In 2023, 30 international partners from 12 European countries launched HyInHeat to demonstrate the use of hydrogen in ancillary processes in aluminium and steel. The Japanese utility Tokyo Gas and building materials manufacturer Lixil tested hydrogen instead of natural gas for heat treatment of aluminium[70], finding that this seemed to have no adverse effect on the quality of products. The European Union-funded H2GLASS project also started in 2023, bringing together 23 partners from around Europe to create a new technology to use 100% hydrogen in high-temperature heating processes in glass and aluminium manufacturing. In 2022, the results of a pilot project using up to 40% hydrogen (on an energy basis) in the main kiln burner at Hanson Cement's Ribblesdale site (United Kingdom) were published, showing no significant impact on the kiln burner or clinker quality. In the transport sector, limited progress has been observed in the past year, although a noteworthy milestone was achieved in March 2023 when the world's first hydrogen ferry entered into operation in Norway. In July 2023, MAN Energy Solutions announced that it had completed the first successful combustion test of a two-stroke ammonia marine engine at its research centre in Copenhagen (Denmark).

[70] FuelCellWorks (2023), Tokyo Gas working with LIXIL on technological verification in the use of hydrogen in the manufacturing process.

Figure 5.7. Technology readiness levels of production of low-emission hydrogen and synthetic fuels, and infrastructure

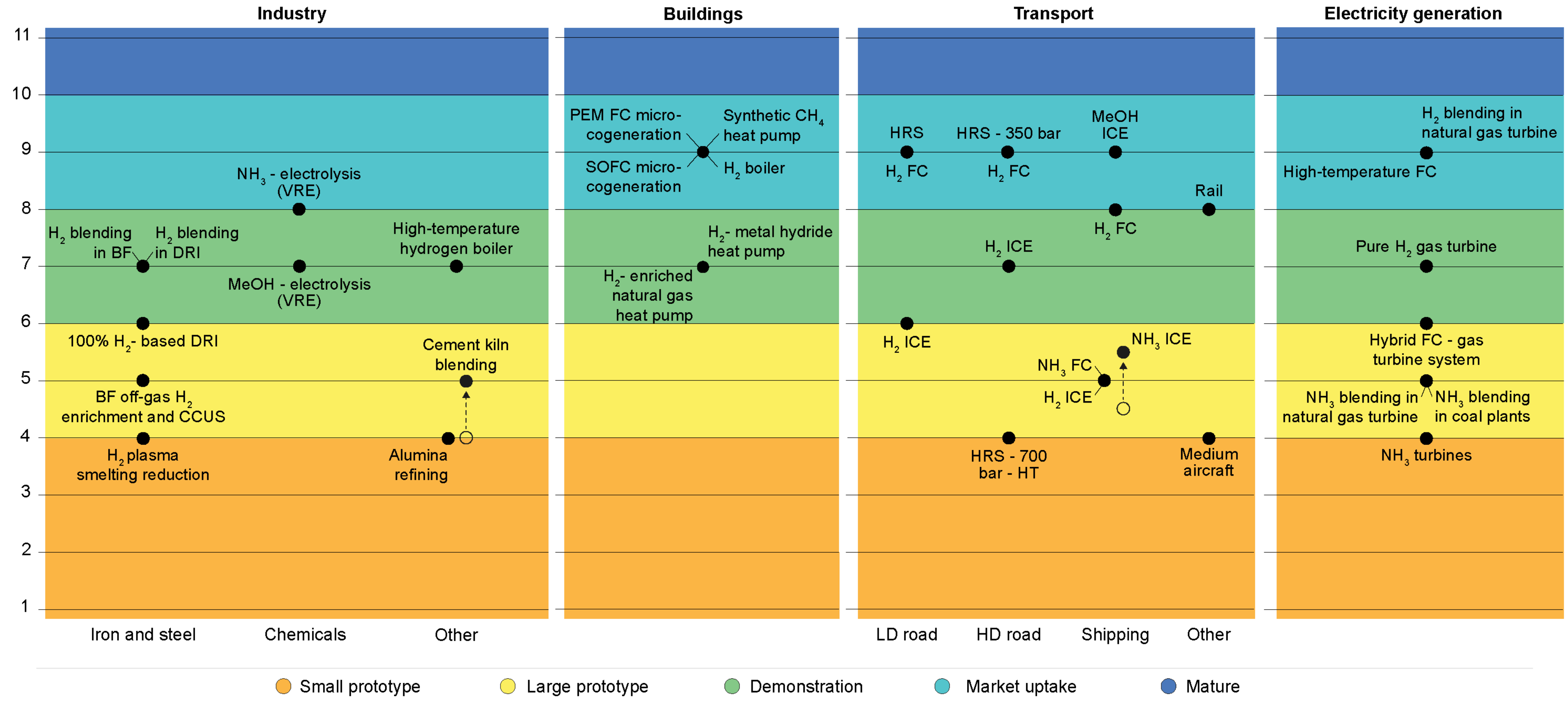


Notes: AEM = anion exchange membrane; ALK = alkaline; ATR = autothermal reformer; CCUS = carbon capture, utilisation and storage; CH_4 = methane; DME = dimethyl ether; GHR = gas-heated reformer; LOHC = liquid organic hydrogen carrier; NH_3 = ammonia; PEM = proton exchange membrane; SOEC = solid oxide electrolyser cell. Biomass refers to both biomass and waste. Arrows show changes in technology readiness level as a consequence of progress in the past year. For technologies in the CCUS category, the technology readiness level refers to the overall concept of coupling production technologies with CCUS and high CO_2 capture rates. Pipelines refer to onshore transmission pipelines. Storage in depleted gas fields and aquifers refers to pure hydrogen and not to blends. LOHC refers to hydrogenation and dehydrogenation of liquid organic hydrogen carriers. Ammonia cracking refers to low-temperature ammonia cracking. Technology readiness level classification based on Clean Energy Innovation (2020).

Sources: IEA Clean Tech Guide (2023); IEA Hydrogen Technology Collaboration Programme.

Several hydrogen production technologies are already commercial, and others are maturing fast, while more innovation is needed in transport and storage technologies.

Figure 5.8. Technology readiness levels of hydrogen end uses by sector



Notes: BF = blast furnace; DRI = direct reduced iron; FC = fuel cell; HRS = hydrogen refuelling station; HD = heavy-duty; HT = high throughput; ICE = internal combustion engine; LD = light-duty; MeOH = methanol; NH_3 = ammonia; PEM FC = proton exchange membrane fuel cell; SOFC = solid oxide fuel cell; VRE = variable renewable electricity. “Other” in industry includes all industrial sectors except methanol, ammonia and iron and steel production. “Other” in transport includes rail and aviation. Arrows show changes in technology readiness level as a consequence of progress in the last year. Cogeneration refers to the combined production of heat and power. Technology readiness level classification based on Clean Energy Innovation (2020).

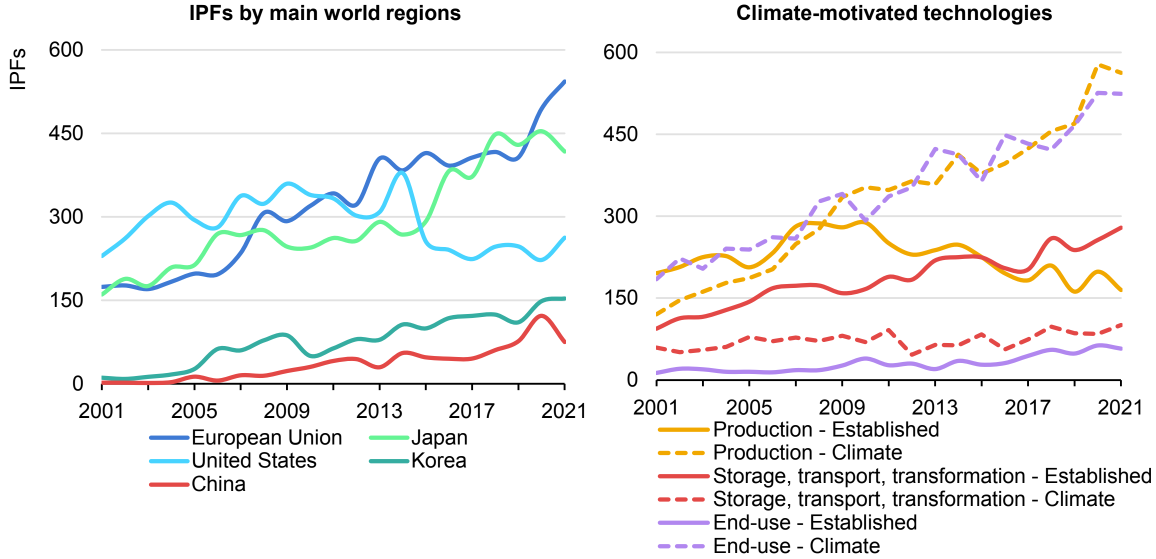
Source: IEA Clean Tech Guide (2023); IEA Hydrogen Technology Collaboration Programme.

Few key end-use hydrogen technologies are commercial, and innovation is progressing slowly on most fronts.

Tracking patent applications

In January 2023, the IEA and the European Patent Office (EPO) released the joint report [Hydrogen patents for a clean energy future](), assessing trends in hydrogen patents from 2000 to 2020. This section presents an update of the analysis including data from 2021, which is the latest data available from the EPO.

Figure 5.9. Patenting trends on hydrogen technologies in the main world regions, 2001-2021



Notes: IPFs = international patent families. The calculations are based on the country of the IPF applicants, using fractional counting in the case of co-applications. "Established" refers to well-established processes in the chemicals and refining sectors and "Climate" refers to emerging technologies that could help mitigate climate change by making hydrogen a clean energy product for a much wider range of sectors that would otherwise use fossil fuels.
Source: IEA analysis based on data from the European Patent Office.

Global hydrogen patenting surges as climate-motivated technologies take the lead, with the European Union and Japan at the forefront.

Since the 2000s, global hydrogen patenting, as measured by international patent families (IPFs), has surged at a compound annual growth rate of 5%.[71] The European Union and Japan are leading the growth, accounting for 28% and 24%, respectively, of all IPFs filed between 2011 and 2021. In the European Union, Germany (12% of the global total), France (6%) and the Netherlands (3%) lead the way (Figure 5.9). Meanwhile, the United States, with 19% of all hydrogen-related patents, is the only major innovation centre with a decline in IPFs over the last decade across all elements of the hydrogen value chain. Korea accounts for 8% of all IPFs filled from 2011 to 2021, with a remarkable compound annual

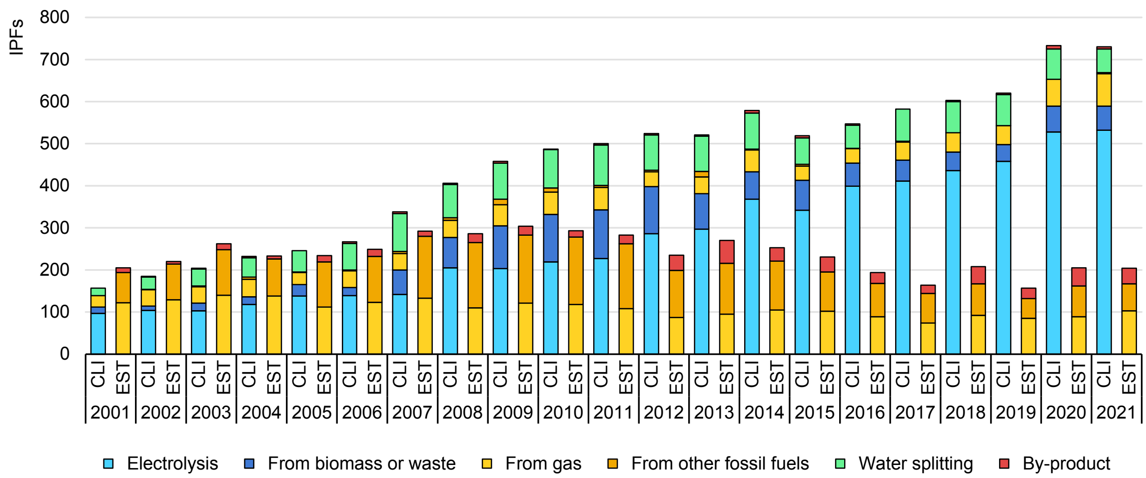
[71] An international patent family represents an invention for which patent applications have been filed at two or more patent offices worldwide. It is used as a means of identifying higher-value patents.

growth rate of 14% since 2001. China's international patenting activity remains modest (4%) but is on the rise, while the United Kingdom (3%), Switzerland (2%) and Canada (2%) also make noteworthy contributions to global patenting.

The number of IPFs in hydrogen end-use technologies, although smaller than for production technologies, has already been boosted by technologies which are motivated by climate concerns. However, only in the past decade has there been a significant shift in hydrogen production technologies, moving away from traditional unabated fossil-based methods towards new technologies with the potential to produce low-emission hydrogen. For production technologies, the transition from established technologies to climate-motivated ones has been driven primarily by the rapid growth of electrolysis technologies. Accordingly, more than two-thirds of the IPFs in the hydrogen value chain now come from low-emission technologies.

Over the last decade, IPFs for electrolysis have more than doubled (Figure 5.10). IPFs for alkaline electrolysis have increased but remain lower than for PEM or SOEC, reflecting the greater maturity of the technology. While IPFs for PEM have generally been higher than those for SOEC, there was a shift in 2021, when the number of IPFs for SOEC overtook those for PEM. IPFs for AEM electrolysis, although still moderate, have shown steady growth, especially in the last two years.

Figure 5.10. Patenting trends in hydrogen production by technologies, 2001-2021

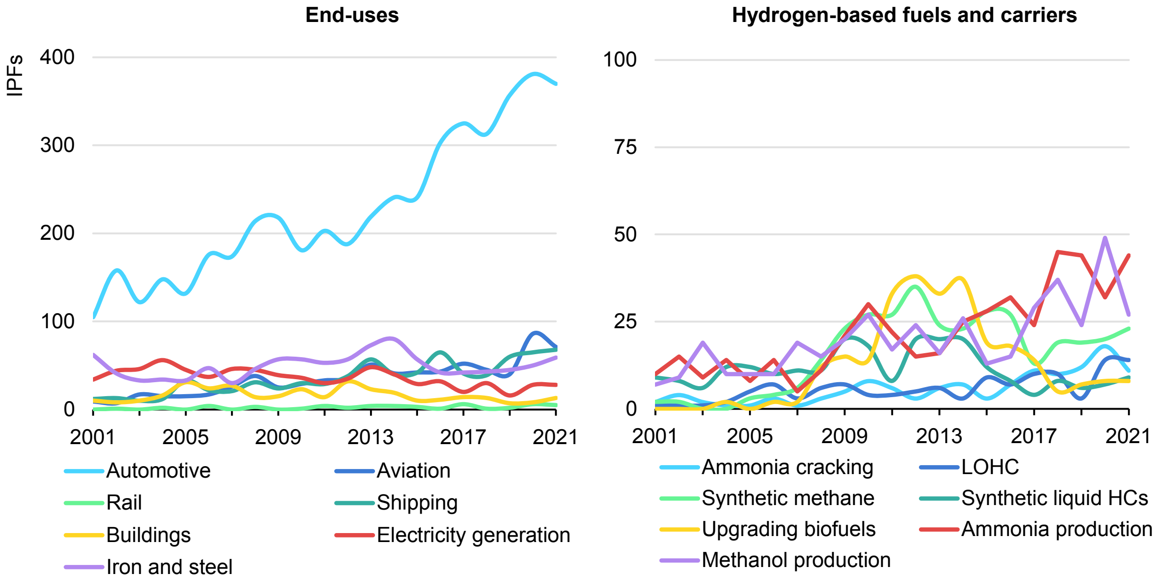


Note: CLI = Climate technologies; EST = Established technologies; IPFs = international patent families.
Source: IEA analysis based on data from the European Patent Office.

Hydrogen production technologies are experiencing rapid growth in patenting, boosted by the rise of electrolysis and natural gas-based pathways with CCUS.

Patenting in hydrogen production from unabated fossil fuels peaked in 2009 and since then there has been a moderate decline in IPFs. However, recent years have seen a rise in innovation in natural gas-based technologies driven by climate concerns (i.e. explicitly including the possibility of CO_2 capture and storage), with a growth between 2019 and 2021 of over 70%, and with the United States playing a major role.[72]

Figure 5.11. Patenting trends in technologies that consume hydrogen, 2001-2021



Notes: HCs = hydrocarbons. IPFs = international patent families. LOHC = liquid organic hydrogen carrier. Synthetic liquid hydrocarbons include synthetic diesel and synthetic kerosene production.
Source: IEA analysis based on data from the European Patent Office.

Patenting activity for key hydrogen-consuming technologies that enable decarbonisation in sectors in which emissions are hard to abate remains remarkably low.

In hydrogen end-use technologies, around 90% of IPFs were driven by climate concerns. Patents for hydrogen use in the automotive sector continue to grow at very high rates, led by Japan (38% of IPFs from 2011 to 2021) and Europe (25%) (Figure 5.11). Aviation and shipping have lower levels of innovation, despite record annual growth of 10% over the last two decades, with Europe (40%) and the United States (33%) dominating aviation and Europe (37%) and Japan (20%) leading shipping. However, other industrial applications with limited decarbonisation alternatives, such as steel production or hydrogen- and hydrogen-based fuels turbines, lack significant innovation. Patenting for hydrogen

[72] Further insights on geographical trends by technology type are presented in the report [Hydrogen patents for a clean energy future.]

use in buildings has declined since the 2010s, suggesting a lack of interest due to more suitable decarbonisation options.

Patent data show an increase in innovation for established hydrogen applications in methanol and ammonia production since the late 2000s. Europe (50% of the IPFs from 2011 to 2021, including 14% from Switzerland) and Japan (22%) lead in ammonia production patenting, while Europe (65%) dominates in methanol production. Over the past decade, patenting for liquid organic hydrogen carriers (LOHCs) and ammonia cracking technologies experienced moderate growth. However, innovation in the development of hydrogen-based fuels, such as synthetic kerosene, synthetic diesel or synthetic methane lost momentum, and efforts led by Europe (36%) and the United States (22%) have stagnated.

While there are overall positive signals for growth of IPFs in hydrogen technologies, this is largely driven by a focus on hydrogen production, particularly on electrolysis. However, there remains a significant innovation gap on end-use technologies, especially in sectors where decarbonisation alternatives are limited. Governments must target innovation efforts accordingly, as there is a risk of a mismatch between supply and demand technologies. Recognising that the hydrogen value chain is only as strong as its weakest link, it is critical to address this gap.

Chapter 6. Policies

Strategies and targets

Since the release of the Global Hydrogen Review 2022 (GHR 2022), 4 governments have updated their hydrogen strategies and a further 15 governments – mostly from emerging markets and developing economies (EMDEs) – have adopted new national hydrogen strategies. A total of 41 governments, accounting for nearly 80% of global energy-related CO_2 emissions, have now adopted hydrogen strategies (Table 6.1).

Table 6.1 National hydrogen roadmaps and strategies since September 2022

Government	Description
Algeria	Target to produce and export 30-40 TWh of hydrogen and hydrogen-based fuels by 2040. Focus on pilot projects until 2030 to start up the sector.
Brazil	The 2023-2025 Triennial Work Plan of the National Hydrogen Program defines the strategy of the country, with three timeframes: by 2025, deploy low-carbon hydrogen pilot plants across the country; by 2030, consolidate Brazil as a competitive low-carbon hydrogen producer; and by 2035 consolidate low-carbon hydrogen hubs in Brazil.
Costa Rica	Target to install 0.15-0.50 GW of electrolysis capacity, to replace 8-10% of liquefied petroleum gas (LPG) with “green” hydrogen and to deploy 100-250 fuel cell electric vehicles (FCEVs) and 200-600 fuel cell heavy-duty trucks by 2030.
Ecuador	Target to install 3 GW of electrolysers by 2040 and establish regulations for domestic hydrogen use and potentially for export to international markets.
India	Target to produce 5 Mt of “green” hydrogen by 2030 (with associated 125 GW of renewable capacity additions) with additional potential to reach 10 Mt/yr with exports. Interest in developing a domestic electrolyser manufacturing industry.
Israel	Plans explore options to integrate hydrogen into the national energy mix, along with consideration of underground storage.
Kenya	Target to install 150-250 MW of electrolysers and to produce 300-400 kt of nitrogen fertilisers by 2032. Aim to develop a local “green” fertiliser industry to decrease dependency on imported fertilisers.
Namibia	Target to produce 1-2 Mt of “green” hydrogen by 2030 and 10-15 Mt by 2050. Aims to develop three hydrogen valleys* to start production and use.
Panama	In transport, the country aims to increase hydrogen and derivatives for maritime fuels bunkering to 5% by 2030. Target to produce 0.5 Mt of hydrogen by 2030.
Singapore	Aim to transform Singapore into a hub for hydrogen and hydrogen fuels in the Pacific. Strong focus on electricity generation, with an estimate that hydrogen could meet up to 50% of electricity demand in 2050, as well as aviation and maritime.
Sri Lanka	Roadmap includes plans to export hydrogen derivatives by 2030.
Türkiye	Target to install 2 GW of electrolysers by 2030, 5 GW by 2035 and 70 GW by 2053. Support for demonstration projects for “blue” hydrogen production.
United Arab Emirates	Strategy includes a forecast for the production of 1.4 Mt of hydrogen by 2030, 7.5 Mt by 2040 and 15 Mt by 2050, through a mix of electrolysis powered with renewable and nuclear electricity, and natural gas with carbon capture, utilisation and storage (CCUS).
United States	Target to produce 10 Mt of “clean” hydrogen by 2030, 20 Mt by 2040 and 50 Mt by 2050. Update every 3 years (required by the Bipartisan Infrastructure Law).
Uruguay	Target to install 1-2 GW of electrolysers by 2030 and 10 GW by 2040, with initial focus on domestic demand in the short term and exports in the long term.

Government	Description
Belgium (update)	Vision structured around four pillars: become an import/transit hub for renewable hydrogen in Europe, expand technology leadership, establish a robust domestic market and international co-operation.
Germany (update)	Target to install 10 GW of electrolysers by 2030, and increased demand in industry and transport to replace larger shares of natural gas, with over 1 800 km of pipeline infrastructure.
Japan (update)	Interim target for 12 Mt of hydrogen demand by 2040 (complementing previous targets for 3 Mt by 2030 and 20 Mt by 2050) and to meet 1% of the gas supply in existing networks with synthetic methane by 2030, increasing to 90% by 2050. Target to install 15 GW of electrolysis globally. Shift focus from FCEVs to the use of hydrogen in applications, notably in steel and petrochemical industries.
Korea (update)	Updated target to reach 2.1% of total electricity production with hydrogen and ammonia by 2030, and 7.1% by 2036. Creation of a framework for a Clean Hydrogen Certification Mechanism to be released by the end of 2023.

*A hydrogen valley is a geographical area – a city, region, island or industrial cluster – where several hydrogen applications are combined together into an integrated hydrogen ecosystem that consumes a significant amount of hydrogen, improving the economics behind the project.

Notes: "Update" refers to strategies and roadmaps published for the first time before September 2022 that have since been updated. See Explanatory notes annex for the use of the terms "green", "blue" and "clean" hydrogen in this report.

These announcements of hydrogen strategies serve as the biggest driver of government funding. India's National Green Hydrogen Mission includes nearly INR 2 billion (Indian rupees) (~USD 25 million) subsidy to produce 5 Mt of hydrogen for domestic consumption and 10 Mt of hydrogen for exports by 2030. The United States adopted the US National Clean Hydrogen Strategy and Roadmap, revising their strategy to accord with recent carbon capture, utilisation and storage (CCUS), renewables, and sustainable aviation fuel (SAF) production tax credits and funding opportunities. In addition, Belgium, Germany, Japan and Korea have updated their existing hydrogen strategies, and a number of countries, particularly in Europe, are in the process of revising their strategies.

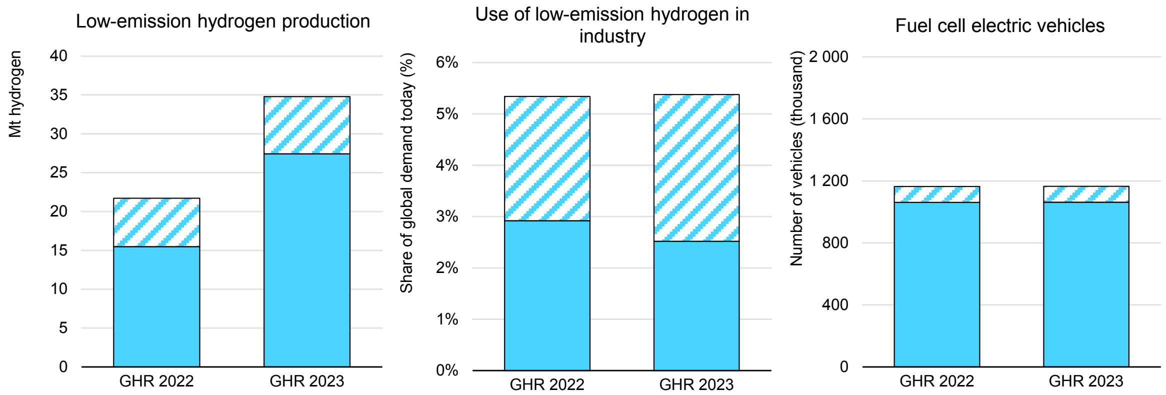
The new and updated strategies show an increase in global ambitions to deploy hydrogen technologies, as reflected in government targets for low-emission hydrogen[73] production, which now account for 27 to 35 Mt, compared with 15 to 22 Mt at the time the GHR 2022 was released (Figure 6.1). The biggest contributors to this increase are the targets of the United States (10 Mt of "clean" hydrogen), India (5 Mt of "green" hydrogen) and Namibia (1-2 Mt of "green" hydrogen).[74]

On the demand side, however, there has been no increase in ambition, and only two significant developments. In the European Union there has been a political agreement to set binding targets for the use of renewable fuels of non-biological origin (RFNBO) in industry, transport and aviation by 2030, though some targets were less ambitious than those proposed in the Fit for 55 package in 2021 (e.g. 42% of hydrogen demand to be met with renewable hydrogen, compared to an

[73] See Explanatory notes annex for low-emission hydrogen definition in this report.
[74] See Explanatory notes annex for the use of the terms "green" and "clean" hydrogen in this report.

initial target of 50%). Binding targets of this kind can send a clear signal to industry about a future marketplace for low-emission hydrogen and hydrogen-based fuels. In Japan, the updated Basic Hydrogen Strategy includes a target to meet 1% of the gas supply in existing networks with synthetic methane by 2030.

Figure 6.1 Global targets for low-emission hydrogen production, use in industry and fuel cell electric vehicles by 2030



Notes: GHR = Global Hydrogen Review. For countries that do not have a production target, the low-emission hydrogen production is estimated from the capacity targets assuming a capacity factor of 57% and an energy efficiency (LHV) of 69% for electrolysers and 90% for fossil-based technologies. The dashed area represents the ranges of policy targets.

Global targets for low-emission hydrogen production keep growing, whereas targets for end use remain stalled.

Demand creation

Policy action is an important driver of demand for low-emission hydrogen to both replace hydrogen produced with unabated fossil fuels in existing applications and to replace fossil fuels in new applications. Action on this front, however, is significantly lagging behind what is needed to achieve climate goals (see Chapter 2 Hydrogen use).

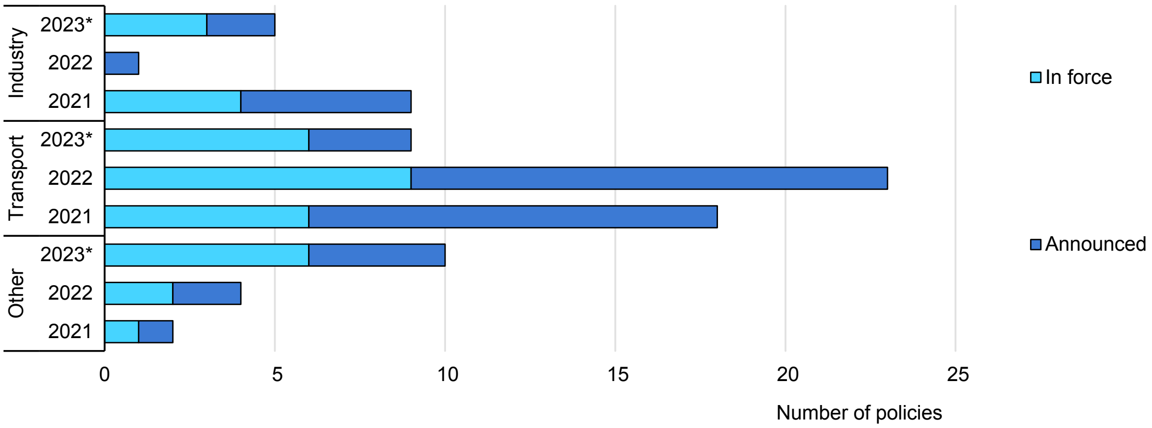
Policy efforts in this area have so far been limited, and despite some signs of progress, the past year was no exception. In 2022, the number of policies for demand creation that governments either announced or implemented remained almost the same as in 2021, with activity has slightly accelerating until August 2023. However, this may soon change following the political agreement of the European Commission, Council and Parliament to adopt mandatory targets for member states on hydrogen demand in industry and transport, and mandates for synthetic fuels in aviation. In addition, the FuelEU Maritime initiative includes the possibility of introducing a target for 2% of RFNBO in maritime fuels from 2034 if these fuels have not reached a 1% share by 2031. These agreements are already having an effect, with Romania's parliament passing in June 2023 a law that sets mandates for renewable hydrogen use in industry and transport, including penalties for non-compliant companies. In the same month, the Netherlands announced plans to introduce subsidies on the demand side during 2024 and obligations for renewable hydrogen in industry (by 2026) and transport (by 2025).

There have also been developments outside of Europe. India announced in 2021 intentions to adopt quotas for refining, fertilisers and steel, which were finally not included in the National Green Hydrogen Mission, but remain under discussion and could be adopted in the near future. New Zealand launched a consultation on a consumption rebate scheme to be implemented from 2025, and the United States announced a USD 1 billion plan to stimulate demand for low-emission hydrogen, although details will not be released until later this year. The states of Colorado and Illinois have already passed bills with a tax credit for companies that use low-emission hydrogen to replace fossil fuels.

Supporting demand creation in different sectors

Most policies to support demand creation that have either been announced or put into place thus far target transport applications (Figure 6.2), such as subsidies for purchasing FCEVs and for the development of hydrogen refuelling stations (HRS), and more recently quotas and mandates. Despite industry and refining accounting for practically all the demand for hydrogen today, the number of policies to create demand for low-emission hydrogen in these sectors is very low. The low-carbon fuel standard in California is today the only policy to have been implemented that targets the stimulation of low-emission hydrogen demand in refining, but the European Union-agreed mandatory target for the use of RFNBOs in transport (which also includes use in refining) is expected to lead to the implementation of policies in member states. In the case of electricity generation, policy action has been concentrated in Southeast Asia, with Japan and Korea leading developments. Korea introduced the world's first hydrogen power bidding market, with the first tender winners announced in August. Japan announced capacity auctions for low-carbon technologies, including hydrogen and ammonia co-firing at fossil fuel power plants, with the first auction expected by October 2023.

Figure 6.2 Number of policies to support hydrogen demand creation announced and entering in force by sector, 2021-2023



Notes: "Other" includes use in buildings, electricity generation and grid blending. 2023* = year to August 2023 only.

Policies for demand creation remain limited and highly concentrated in the transport sector.

Mitigating investment risks

While demand targets have remained low this year, governments have adopted various financial tools to provide medium- to long-term stability across the whole value chain. Grants and subsidies are already commonly employed to reduce CAPEX (Table 6.2), and some governments have established other types of incentives to bolster hydrogen production:Table 6.2

- **Tax incentives**: The US Inflation Reduction Act (IRA) passed in 2022 included numerous tax credits for the production of hydrogen and hydrogen-based fuels (Box 6.1), and Canada announced a Clean Hydrogen Investment Tax Credit. In 2023, Egypt also introduced tax rebates for projects producing hydrogen and hydrogen-based fuels from renewable electricity.
- **Contracts for Difference (CfD)**: The United Kingdom adopted a CfD scheme through the UK Low Carbon Hydrogen Business Model. In 2023, Germany established Carbon Contracts for Difference (CCfD) for energy-intensive industries, which companies using low-emission hydrogen to decrease GHG emissions can participate in. Conversely, Japan will introduce a CfD scheme based on the difference between the price of renewable and fossil fuel-based hydrogen without the carbon price bench. More jurisdictions have also announced plans to follow suit with CfDs, including Canada and the European Commission.
- **Competitive bidding schemes for hydrogen production**: Countries such as India, the Netherlands and Denmark have implemented schemes to provide direct payments per kilogramme of hydrogen produced over a certain number of years.

- **Other policies**: the creation of one-stop-shops to co-ordinate policy implementation and regulatory procedures can reduce administrative burdens for project developers. In 2022, Oman created Hydrogen Oman (HYDROM) with this purpose, and just one year later, HYDROM announced the results of the first auction for land allocation to renewable hydrogen projects. The H2Global initiative, which presents a novel double-auction support mechanism, has received a significant boost in government funding from Germany and the Netherlands.

Emerging markets and developing economies (EMDEs) have emphasised the importance of international partnerships and finance. Concessional finance, foreign loans and crowdsourced loans can reduce upfront costs and signal political commitment to hydrogen, potentially further reducing risks for investors. Advanced economies have committed funds through bilateral finance and multilateral development banks to respond to EMDEs' requests and facilitate hydrogen developments in these countries (see Chapter 5 Investment, finance and innovation).

Box 6.1 Financial incentives in the Inflation Reduction Act

In August 2022, the US Inflation Reduction Act (IRA) entered into force. The Act contains numerous incentives to accelerate the deployment of a wide range of clean energy technologies, including hydrogen. The most relevant incentive for hydrogen production is the new Clean Hydrogen Production Tax Credit (45V), which grants a tax credit for a period of ten years for projects that are placed in service before January 2033 and produce "clean hydrogen" (see Explanatory notes annex for the use of the term "clean" hydrogen in this report). The amount of the tax credit varies from USD 0.12 to USD 0.6 per kilogramme of hydrogen produced depending on the emissions intensity of the hydrogen production. The value of these credits is multiplied by five if the facility meets certain labour conditions.

Value of the tax credit granted by the Clean Hydrogen Production Tax Credit

Carbon intensity of hydrogen (kg CO_2-equivalent/kg H_2)	Tax credit (USD/kg H_2)	
	Base credit	Meeting labour conditions
<0.45	0.60	3.00
0.45-1.5	0.20	1.00
1.5-2.5	0.15	0.75
2.5-4.0	0.12	0.60

In addition to the 45V tax credit, the Act contains other tax incentives which stakeholders involved in projects for hydrogen production, investments or associated equipment manufacturing may be able to claim. While guidance for many of these incentives is forthcoming, statutory language in the Act already states that in some circumstances these credits can be combined, improving the economic feasibility of a project. For instance, a project developer that produces hydrogen using electricity from renewable or nuclear electricity may be able to claim the hydrogen production tax credit, while the clean electricity could qualify for production or investment tax credits as well. In other cases, the project developer will need to opt for either the 45V or another incentive. For example, projects producing hydrogen from fossil fuels with CCUS are prohibited from claiming both the hydrogen production tax credit and the CCUS credit.

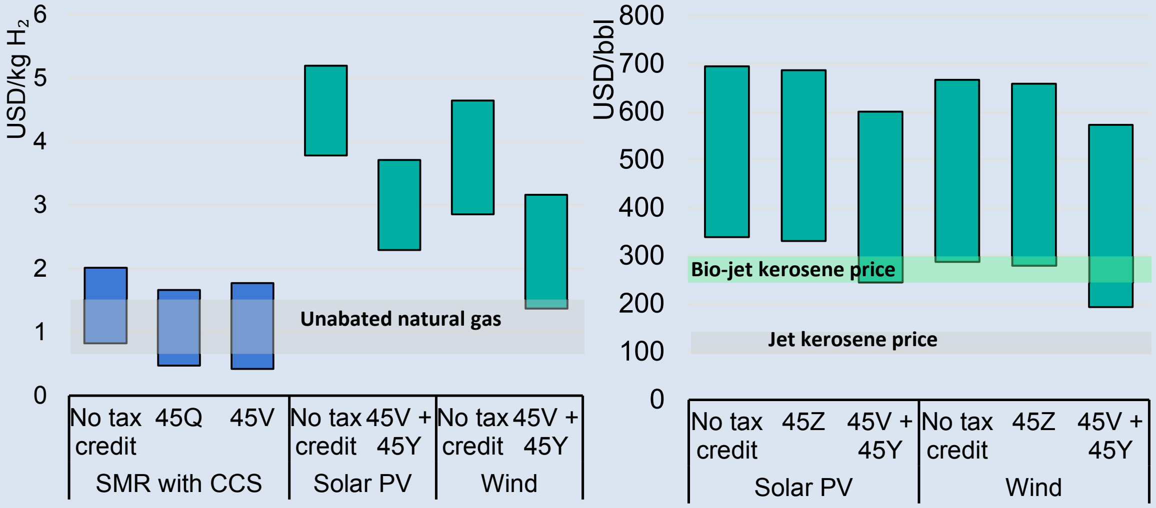
Tax incentives available for "clean" hydrogen and hydrogen-based fuels

Incentive	Description	Credit amount	
		Base	Bonus
Clean Energy Technologies			
45 – 45Y	Tax credit for facilities producing renewable (45) or clean (45Y) electricity	USD 0.003/kWh of electricity produced	x5 for labour standards +10% for domestic content +10% if in an energy community
48 – 48E	Tax credit for investment in renewable energy (48) or clean electricity (48E) projects	6% of qualified investment	
48C	Tax credit for investments in advanced energy projects, as defined in [26 USC § 48C(c)(1)]	USD 10 billion of allocations for investments in advanced energy projects	-
45U	Tax credit for qualified facilities producing nuclear electricity	USD 0.003/kWh of electricity produced	x5 for labour standards
Transportation fuels			
40B	Tax credit for SAF with GHG emissions <50% than fossil-based jet fuel	USD 1.25/gallon	USD 00.50/gallon (depending on GHG reduction)
45Z	Tax credit for production of clean transport fuels, including SAF	USD 0.20/gallon (nonSAF) USD 0.35/gallon (SAF), multiplied by emissions factor of fuel	x5 for labour standards
Carbon sequestration			
45Q	Tax credit for CO_2 sequestration coupled with permitted end uses.	USD 17/t CO_2 (stored) USD 12/t CO_2 (used in EOR) USD 26-36/t CO_2 (DAC facilities)	x5 for labour standards

Notes: DAC = direct air capture; EOR = enhanced oil recovery; SAF = sustainable aviation fuels. 40B will be replaced by 45Z from 2025.

The cost of producing hydrogen from renewable electricity in the United States is in the range of USD 2.9-5.2/kg H_2. However, the 45V and 45Y tax credits combined can reach up to USD 1.5/kg H_2 of subsidy over the 25-year life of a project, which can lower the production cost to USD 1.4/kg H_2 in the regions with the most abundant wind and solar resources. This production cost is within the range of the production cost of hydrogen from unabated natural gas. Projects using natural gas with CCUS to produce hydrogen which choose either the 45Q or 45V subsidy could reach a levelised cost of production in the same range as that of the unabated production route (or even lower in the case of a retrofitted plant and cheap natural gas prices). The IRA tax credits can also have an impact on the production of synthetic liquid fuels, such as synthetic kerosene used in aviation. In this case, producers may be able to claim the 45Z tax credit, although it applies for a shorter timeframe than 45V. The impact of this tax credit could help to reduce the production cost of synthetic kerosene by around USD 10/bbl, but this is still far from current kerosene prices (USD 90-130/bbl at an oil price of USD 75-85/bbl).

Impact of IRA subsidies on the levelised cost of hydrogen and synthetic kerosene production



Notes: SMR = steam methane reforming; CCS= carbon capture and storage. Assuming the plant enters into operation in 2025, with a lifetime of 25 years, and assuming full compliance with prevailing wage and registered apprenticeship requirements. Left chart: Subsidies 45Q, 45V and 45Y assumed to last for 10 years. Natural gas price of USD 1.5-7.3/MBtu. Assuming a 95% capture rate for SMR with carbon capture, utilisation and storage (CCUS), and a retrofitted SMR plant for the lower value of the range. The range for renewable-based hydrogen refers to locations with different capacity factors. Right chart: Subsidies 45V, 45Y assumed to last for 10 years; subsidy 45Z for 3 years. Current prices of jet and bio-jet kerosene refer to the period May-August 2023.

Despite the financial support provided by IRA incentives, there is still considerable uncertainty around how these credits will be implemented, and – in some cases – which projects will be eligible for what level of credit. Further details are expected to be provided by the US Department of the Treasury in the coming months. In addition, there is also uncertainty around the concrete details of the methodology to assess the carbon intensity of hydrogen production (e.g. the temporal correlation between the use of grid electricity and renewable electricity fed into the grid), which are also expected to be clarified by the US Department of Energy in the coming months. Clarity about the implementation of the subsidies and the carbon intensity accounting methodology will provide the certainty that developers require to take firm investment decisions.

In addition to the tax incentives, the Act includes numerous programmes with grants to support clean energy technologies, which projects for the production of "clean" hydrogen and hydrogen-based fuels may be eligible for, and to support adoption of end-use hydrogen technologies.

Table 6.2 Policy measures to mitigate investment risks in hydrogen projects in force or announced since August 2022

Policy	Country	Status	Description
Grants	Australia	In force	In the 2023-24 Federal Budget the government announced the Hydrogen Headstart programme with AUD 2 billion (Australian dollars) (~USD 1.4 billion) to support large-scale renewable hydrogen projects.
	Belgium	In force	In October 2022, the federal government approved EUR 6 million (~USD 6.3 million) to support the development of "green" steel projects, using resources from the federal Recovery and Transition Plan.
	Canada	In force	The Canada Infrastructure Bank launched in September 2022 the Zero-Emission Vehicle (ZEV) Charging and Hydrogen Refuelling Infrastructure Initiative, a CAD 500 million (Canadian dollars) (~USD 384 million) programme to accelerate the private sector's rollout of large-scale ZEV chargers and hydrogen refuelling stations.
	Canada	In force	In November 2022, the government granted CAD 475 million (~USD 365 million) to Air Products to support the development of its Net-Zero Hydrogen Energy Complex in Alberta.
	Estonia	In force	In January 2023 the government opened a new subsidy to promote the introduction of "green" hydrogen in hard-to-electrify sectors. The programme counts a total budget of EUR 49 million (~USD 52 million) for the development of projects covering the whole supply chain of "green" hydrogen, with maximum support of up to EUR 20 million (~USD 21 million) per project.
	European Union	In force	In November 2022 the European Commission announced a EUR 3 billion (~USD 3.2 million) call to support large-scale projects aiming to further innovative technologies, including with relation to hydrogen.
	EU member states	In force and announced	After the first set of Important Projects of Common European Interest (IPCEI) were approved in July 2022, in September 2022 the second IPCEI "Hy2Use" was approved, and EUR 5.2 billion (~USD 5.5 billion) will be used to fund 35 projects for the production, storage, transport and use of renewable hydrogen in innovative industrial applications.
	Germany	In force	In 2023, the Commission approved a EUR 550 million (~USD 579 million) direct grant and conditional payment mechanism of up to EUR 1.45 billion (~USD 1.53 billion) to support ThyssenKrupp Steel Europe in decarbonising its steel production and accelerating renewable hydrogen uptake.
	Italy	In force	In April 2023, within the Temporary Crisis and Transition Framework, the European Commission approved an Italian EUR 450 million (~USD 474 million) scheme to support projects for the production of renewable hydrogen in brownfield industrial areas and in sectors in which emissions are hard to abate.
	Italy	In force	EUR 230 million (~USD 242 million) to support the deployment of HRS in motorways and EUR 300 million (~USD 316 million) to support the deployment of HRS for rail applications
	Japan	In force	In 2023, NEDO committed JPY 220 billion (Japanese yen) (~USD 1.7 billion) to support the next phase of a liquefied hydrogen supply chain project between Australia and Japan.
	Morocco	Announced	In 2023, Morocco's state-owned chemical company OCP announced an investment of USD 7 billion in an ammonia plant that uses renewable-based hydrogen.
	Netherlands	In force	In 2022, the Netherlands' Ministry of Economic Affairs and Climate cleared EUR 784 million (~USD 826 billion) in national subsidies for electrolyser projects linked to the Hy2Use IPCEI.
	New Zealand	Announced	In the 2023 Budget and in the Interim Hydrogen Roadmap, an NZD 30 million (New Zealand dollars) (~USD 19 million) Clean Heavy Vehicles Grant was announced for zero emission heavy vehicles, including fuel cell heavy-duty vehicles.

Policy	Country	Status	Description
Grants (continued)	Poland	In force	In April 2023, the European Commission approved a EUR 158 million (~USD 166 billion) grant from the government of Poland to support LOTOS Green H2, for the production of renewable hydrogen to be used in refining.
	Saudi Arabia	In force	In 2023, the government committed USD 2.75 billion through the National Development Fund and the Saudi Industrial Development Fund to the NEOM "green" hydrogen and ammonia project.
	Spain	In force	In June 2023, the government approved an addendum to the Spanish Recovery and Resilience Plan which included an increase of nearly EUR 5.5 billion (~USD 5.8 billion) in funding provided for the Strategic Project for Recovery and Economic Transformation on Renewable Energy, Hydrogen and Storage.
	Spain	In force	In April 2023, the government approved funding for EUR 450 million (~USD 474 million) to support a hydrogen project of Arcelor Mittal for the production of "green" steel.
	United Kingdom	In force	The UK government allocated GBP 38 million (~USD 47 million) for the front-end engineering and demand (FEED) and CAPEX of 15 low-carbon hydrogen projects.
	United States	In force	In September 2022 the government opened the call for the Regional Clean Hydrogen Hubs, which includes up to USD 7 billion to establish 6 to 10 regional "clean" hydrogen hubs.
Competitive bidding schemes for hydrogen production	Denmark	In force	In 2023, the Commission approved a EUR 170 million (~USD 179 million) Danish scheme to support renewable hydrogen production.
	India	In force	In 2023, the government approved INR 175 billion (~USD 2.2 billion) for the Strategic Interventions for Green Hydrogen Transition programme, which will support domestic production of electrolysers and production of renewable-based hydrogen. The scheme can provide an incentive with an upper cap of INR 50/kg (USD 0.64/kg) for the first year, INR 40/kg (USD 0.51/kg) for the second year and INR 30/kg (USD 0.38/Kg) for the third year of production.
	Netherlands	In force	In 2023, the Commission approved a EUR 246 million (~USD 259 million) scheme to support renewable hydrogen production in the Netherlands.
Tax incentives	Canada	Announced	In the 2022 Fall Economic Statement and Budget 2023, the government announced several tax credits to support the deployment of hydrogen technologies: • Clean Hydrogen Investment Tax Credit to support 15-40% of eligible costs of projects for hydrogen production, with higher support for those with emission intensity under 0.75 kg CO_2/kg H_2. The 15% tax credit was extended to low-carbon ammonia production. • CCUS Investment Tax Credit to provide a 50% credit for equipment associated with point-source CCUS projects, declining in 2030 and 2040 to incentivise early adoption. The proposal was in public consultation until June 2023 and the details of the design of the investment tax credit are expected soon.
	Egypt	In force	In 2023, a bill on incentives for projects for "green" hydrogen and its derivatives was approved. Under the law, such projects will get a cash investment incentive ranging between 33% and 55% of the value of taxes to be paid. Incentives also include exemption from value added taxes for equipment, raw materials and means of transportation.
	United States	Announced	As part of the IRA, the US government offers a Hydrogen Production Tax Credit of USD 0.6-3/kg H_2 based on the carbon intensity of hydrogen production (Box 6.1).

Policy	Country	Status	Description
Tax incentives (continued)	Italy	Announced	The government announced in the Legislative Decree 199/2021 the creation of a tariff mechanism for the promotion of renewable hydrogen, and is studying a mechanism to compensate producers for part of the operating costs of renewable hydrogen plants, also taking into account investment costs for the production plant.
Contracts for Difference (CfD)	Canada	Announced	As part of the Budget 2023, the government will consult on the development of carbon CfD as one of the investment instruments of the Canada Growth Fund, aimed at de-risking projects by providing predictability on prices.
	European Commission	In force	The European Commissions committed EUR 800 million (~USD 842 billion) from the EU Innovation Fund European Hydrogen Bank for the first auction to support projects for the domestic production of renewable hydrogen. The Bank aims to establish 10-year off-take agreements between the buyers and producers by paying a green premium of up to EUR 4.5/kg H_2. The Bank announced that it will also provide support for projects outside of the European Union that aim to export to the region, but this may be implemented jointly with the H2Global Scheme.
	Germany	In force	In June 2023, the government announced a Carbon CfD scheme to support heavy industry shifting towards carbon-neutral energy sources. Companies will bid in an auction based on the volume of emissions and the additional estimated cost incurred per tonne of CO_2 avoided, which will be paid by government to successful bidders. Winners will receive a 15-year contract. Among other technologies, the programme will support both renewable and "blue" hydrogen, as long as they comply with the EU taxonomy for sustainable activities, although the level of support for renewable hydrogen will be higher.
	Japan	Announced	Japan will introduce a CfD on the difference between the price of renewable and fossil fuel-based hydrogen without the carbon price bench. The CfD will apply to companies supplying low-carbon hydrogen or ammonia.
	United Kingdom	In force	The shortlisted projects of the first Electrolytic Allocation Round were announced in March 2023 and the contracts with the finally awarded projects are expected to be finalised by the end of 2023. The second allocation round will follow by the end of 2023.
Other	Germany and the Netherlands	In force	In 2023, the German government committed EUR 4.9 billion (~USD 5.2 billion) to the H2Global initiative, in addition to the EUR 0.9 billion (~USD 1.1 billion) committed in 2021. Also in 2023, the Netherlands decided to join H2Global and provide EUR 0.3 billion (~USD 0.4 billion). H2Global combines a double-auction mechanism, with an intermediary functioning as a dedicated offtake vehicle that sets direct contractual agreements with both producers and buyers of hydrogen-based fuels, and absorbs existing regulatory uncertainties. The price gap between the low-emission and unabated fossil fuel-based hydrogen products is compensated with the available government funding. The bidding process started in December 2022, with deliveries expected for the end of 2024, although tender deadlines have recently been extended.
	India	In force	Renewable hydrogen and ammonia projects entering into operation before the end of 2030 will not pay electricity transmission charges. For projects being commissioned after 2030, the waiver will be gradually reduced until being removed for projects commissioned after January 2036.
	Oman	In force	In 2022, the government established Hydrogen Oman (HYDROM), a fully owned autonomous subsidiary of Energy Development Oman, with the mandate to structure large-scale "green" hydrogen projects, managing the auction process for allocating government-owned lands to projects, assisting in the development of common infrastructure and overseeing the execution of projects. In April 2023, HYDROM released the result of the first auction for land allocation to renewable hydrogen projects, with 6 projects worth USD 20 billion being awarded.

Note: See Explanatory notes annex for the use of the terms "green", "blue" and "clean" hydrogen in this report.

Industrial policies to support domestic manufacturing of hydrogen technologies

Governments are increasingly putting domestic clean technology manufacturing at the heart of their industrial strategies, with commitments to scale up investments and diversify supply chains. This is partly to avoid potentially risky levels of concentration in the supply chain, especially in the light of China's outsize role in much clean energy technology manufacturing and in processing and refining many of the critical minerals required for a global clean energy transition.

In addition to the US IRA, which is accompanied by new authority to use USD 500 million in funding from the Defense Production Act to increase production of key clean energy technologies including electrolysers, a number of other governments have announced and adopted policies to support domestic manufacturing of hydrogen technologies.

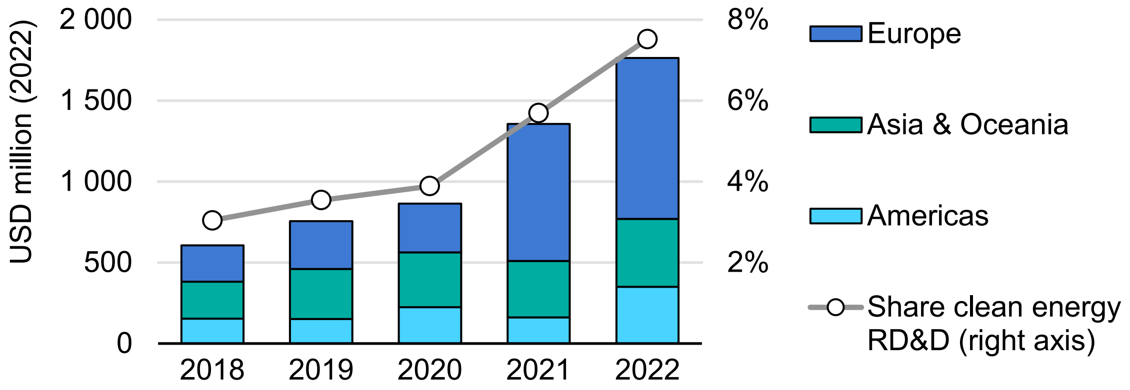
Canada's government announced in its 2022 Fall Economic Statement the creation of Clean Technology Manufacturing Investment Tax Credits to support Canadian companies that manufacture or process clean technologies and critical materials. This does not specifically support hydrogen technologies, but it supports the extraction, processing and recycling of critical minerals used in electrolysers and fuel cells. In March 2023, the European Commission announced the Net Zero Industry Act, which includes measures to strengthen manufacturing to achieve the objective of domestically manufacturing at least 40% of the technology required to achieve the European Union's 2030 climate and energy goals. In May 2023, India announced the implementation of tenders to support 15 GW of electrolysis manufacturing capacity in the country, with a first call (for 1.5 GW) launched in June 2023. In the same month, the government of the Netherlands launched a consultation on a potential subsidy for manufacturers in the hydrogen supply chain, including for electrolysers, with a total budget of EUR 838 million (~USD 882 million).

Promotion of RD&D and knowledge-sharing

Government investment in RD&D in hydrogen technologies increased strongly in 2022.[75] This represents a continuation of the trend observed since the mid-2010s, which has accelerated in the past two years. The growing interest of governments in the development of hydrogen technologies is also represented by the increased share allocated to hydrogen in clean energy RD&D budgets, which reached its historical maximum at 7.5% in 2022 (Figure 6.3).

[75] The IEA has collected data on energy RD&D spending in member countries since 2004. Data on RD&D spending in Brazil has been collected since 2013.

Figure 6.3 Government RD&D spending for hydrogen technologies by region, 2018-2022



Note: Data includes IEA member countries and Brazil.

Public budgets for RD&D on hydrogen are growing strongly, with the United States leading the growth in 2022.

Beyond basic R&D, demonstration is a critical enabler for the scale-up of low-emission hydrogen production and use. There have been a limited number of new (or extended) demonstration programmes compared with previous years (Table 6.3), but governments have started to focus efforts on end-use applications, particularly in those applications where hydrogen can play a key role in a net zero future. This is especially true of heavy industry applications, which are responsible for the majority of the new demonstration programmes, in line with IEA recommendations.

The increase in public RD&D investment results from a combination of the extension and new phases of previously announced programmes, as well as the implementation of new programmes. Practically all governments have increased their RD&D budgets, with the United States responsible for the largest share of growth in 2022. In September 2022, the Regional Clean Hydrogen Hub programme opened its first call for proposals to develop six to ten hubs. In addition, as part of the USD 8 billion of funding under the Bipartisan Infrastructure Bill, the US government earmarked an annual budget of USD 200-400 million for basic and applied R&D, USD 200 million for electrolyser RD&D, and USD 100 million for manufacturing and recycling RD&D. In addition to this budget, the United States allocated a total of USD 319 million in FY 2022 for hydrogen programmes led by the Hydrogen and Fuel Cell Technologies Office within the Office of Energy Efficiency and Renewable Energy. Elsewhere, another major announcement took place in July 2023, when India published an R&D "green" hydrogen roadmap, establishing priorities on manufacturing of hydrogen technologies and infrastructure, although this is not yet reflected in RD&D budgets.

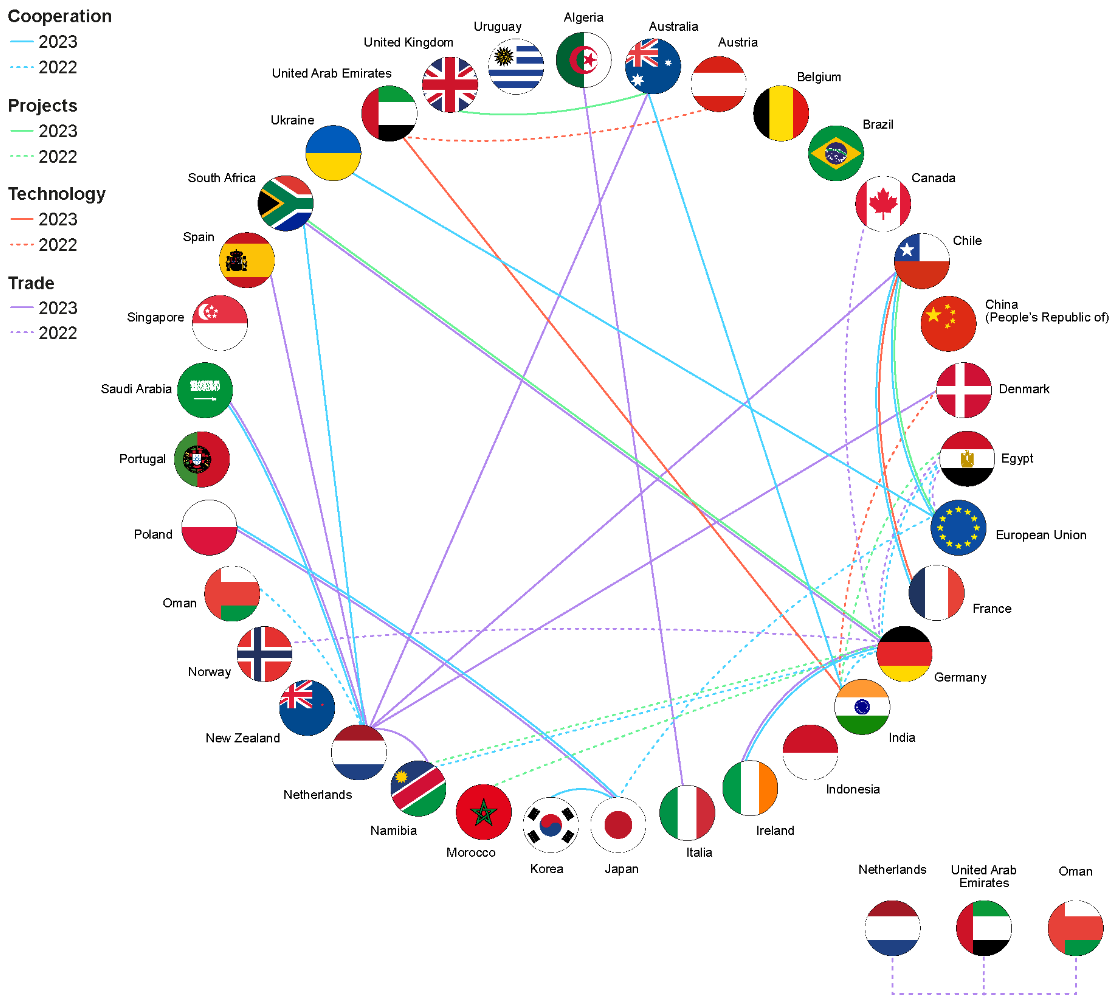
Table 6.3 Selected government programmes which include support for hydrogen technology demonstration projects since August 2022

Government	Programme	Description
Australia	Hydrogen Direct Reduced Iron Production plant	The Australian Renewable Energy Agency announced AUD 0.9 million (Australian dollars) (~USD 0.7 million) funding to Calix Ltd. to evaluate a low-emission method for reducing iron.
Belgium	Grant to strengthen import strategy	Launch of a EUR 10 million (~USD 10.5 million) call for projects concerning RD&D of infrastructure for hydrogen imports, financed under the federal Recovery and Transition Plan.
Denmark	ESAF-Aal project	DKK 9.71 million (Danish kroner) (~USD 1.4 million) granted to demonstrate a technology to convert e-methanol to e-SAF in a single step, towards the aim of operating domestic SAF flights by 2025.
European Union	Clean Hydrogen Partnership	EUR 195 million (~USD 205 million) funding to develop hydrogen technologies in different areas, including renewable hydrogen production, hydrogen valleys, storage, distribution and transport.
Germany	Reallabore der Energiewende	The programme, which has a specific call for hydrogen, supports industrial demonstration with up to EUR 25 million (~USD 26 million), with up to EUR 15 million (~USD 16 million) per partner.
Netherlands	TSE Industrie studies	Open for 1 year from April 2023, the scheme provides EUR 20 million (~USD 21 million) for feasibility and environmental studies for pilot and demonstration projects.
Netherlands	DEI+	The EUR 40 million (~USD 42 million) subsidy includes funding for hydrogen demonstration projects.
New Zealand	(unknown)	In the Interim Hydrogen Roadmap, the government announced an allocation of NZD 7.5 million (~USD 4.8 million) toward a range of trial and demonstration initiatives.
Korea	R&D budget for hydrogen-related technologies	The country earmarked KRW 205.9 billion (Korean won) (~USD 159 million) to develop technologies for electrolysis, fuel cells and low-carbon power generation, including an ammonia co-firing demonstration project from 2023-27.
Spain	H2 Pioneros	The second call of the programme will allocate EUR 150 million (~USD 158 million) to 0.5 MW to 50 MW electrolysis demonstration projects for local consumption in sectors which are hard to abate.
United Kingdom	Clean Maritime Demonstration Competition Round 3	To accelerate the design and manufacturing of clean maritime technologies, up to GBP 60 million (~USD 74 million) funding is being made available for demonstrations of on-vessel technologies or shoreside infrastructure.
	Hydrogen BECCS Innovation Programme	Phase 2 of the GBP 25 million (~USD 31 million) programme will support the demonstration of hydrogen bioenergy with carbon capture and storage (BECCS) technologies.
	Red Diesel Replacement competition	Phase 2 of the GBP 32.5 million (~USD 40 million) competition will demonstrate a low-carbon alternative to red diesel on a construction and mining or quarrying site and increase TRL to 7 upon completion.
	Industrial Hydrogen Accelerator (IHA) Programme	Includes GBP 26 million (~USD 32 million) to finance the demonstration of end-to-end industrial fuel switching to hydrogen. Under Stream 2B, each demonstration project can apply for up to GBP 7 million (~USD 8.6 million).
United States	Support of Hydrogen Shot	Through the H2@Scale Initiative, USD 47 million will be awarded for R&D areas including hydrogen carriers, onboard storage systems, transfer and fuelling for liquid hydrogen and membrane electrode assemblies.
	Clean Hydrogen Electrolysis, Manufacturing, and Recycling	Provides USD 750 million over a period of 5 years to reduce the cost of hydrogen production to less than USD 2/kg by 2026, advance manufacturing and innovate the reuse and recycling of relevant technologies.

International co-operation

International co-operation for hydrogen is increasing beyond finance (which is covered in Chapter 5 Investment, finance and innovation), most notably for trade, as a response to the energy crisis andChapter 5 Investment, finance and innovation growing concerns about energy security and diversification of supplies. Since the release of GHR 2022, 31 hydrogen-specific bilateral agreements for co-operation have been signed by governments around the world, 15 of which focus on trade. In addition, hydrogen is becoming a more common topic in general co-operation agreements. Since 2022, 31 bilateral co-operation agreements on energy topics have included hydrogen among the areas cited in the agreement (Figure 6.4).

Figure 6.4 Co-operation agreements between governments on hydrogen since August 2022.



Notes: "Projects" refers to co-operation agreements to develop hydrogen-related projects. "Technology" refers to co-operation agreements to work on innovation, RD&D and technology development. "Trade" refers to co-operation agreements to develop international hydrogen supply chains. "Co-operation" refers to co-operation agreements with a different focus to the other categories. Only co-operation agreements specific to hydrogen and its derivatives are depicted in the figure.

Co-operation among governments on hydrogen remains strong, with an important focus on the development of international supply chains.

The growing interest in hydrogen trade and in the creation of an international market for hydrogen and hydrogen-based fuels has pushed co-operation beyond bilateral agreements. In July 2023, in Goa (India), 14 governments signed a joint declaration for the creation of an International Hydrogen Trade Forum within the framework of the Clean Energy Ministerial Hydrogen Initiative. The aim is for the forum to become the main platform to foster dialogue between potential importing and exporting countries.

Other multilateral co-operations have also strengthened their work on hydrogen. The G7, in its Climate, Energy and Environment Ministers' Communiqué, committed to enhance efforts on the development of a global market, including reliable international standards and certification schemes, as well as building the enabling environment to encourage safe use of hydrogen, promoting relevant regulations, safety codes and standards. The G20, in the Energy Transitions Ministers' Meeting Outcome Document and Chair's Summary, agreed five High Level Voluntary Principles on Hydrogen to support the acceleration of production, utilisation and development of transparent and resilient global markets for hydrogen. At the 27th Conference of the Parties (COP 27), countries under the Breakthrough Agenda agreed to take action to strengthen demand signals, to accelerate and expand a co-ordinated programme of work to develop standards and associated certification schemes, to increase the number and geographical distribution of hydrogen demonstration projects and to facilitate access to increased concessional finance and other mechanisms for EMDEs.

Standards, certification and regulations

Standards, certification and regulation on the environmental attributes of hydrogen

The establishment of standards, regulations and certification systems that address the environmental attributes of hydrogen and ensure compliance are of paramount importance to facilitate the adoption of low-emission hydrogen. Over the past few years, stakeholders – spearheaded by the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) – have concentrated their efforts on developing a common global methodology for GHG emissions accounting throughout the life-cycle of hydrogen and its derivatives.

The IPHE has finalised its Methodology for determining the GHG emissions associated with the production, conversion and transport of hydrogen. This document will play a crucial role in the development of an International Standard by the International Organization for Standardization (ISO). The ISO aims to publish a Technical Specification by the end of 2023 and subsequently a draft International Standard by the end of 2024.

Governments worldwide are simultaneously taking steps to implement regulations and certification systems pertaining to the environmental attributes of hydrogen (Table 6.4). There are currently seven national and supranational governments with regulatory frameworks in place. A further six countries have announced forthcoming regulations, although the specific methodologies to demonstrate compliance with these frameworks are yet to be determined.

While these certification systems and regulatory frameworks share certain similarities in terms of scope, system boundaries and eligibility criteria, there are also significant divergences. This variability poses challenges for project developers – particularly those aiming to participate in a potential global market – who need to undertake ad-hoc certification processes for each country they wish to access, resulting in increased transaction costs.

Consequently, in the absence of greater interoperability in regulatory frameworks and certification, trade in hydrogen is likely to be limited to bilateral agreements, impeding the development of an international market. The establishment of a global hydrogen market could be greatly aided by collaboration and co-operation among governments to foster a certain level of interoperability among regulatory frameworks. A full harmonisation of these certification systems and regulatory frameworks seems infeasible in the short term, but enabling mutual recognition among the different certification schemes can be a first step to minimise market fragmentation. In July 2023, the IEA Hydrogen Technology Collaboration Programme started a new Task on Hydrogen Certification to work on technical matters of harmonisation of certification. The need for mutual recognition of certification schemes was also acknowledged in the G20 Energy Transitions Ministers' Meeting Outcome Document and Chair's Summary, and in the G7 Climate, Energy and Environment Ministers' Communiqué. Referencing the emissions intensity of hydrogen production, based on a joint understanding of the methodology employed for regulation and certification, can be a starting point to enable mutual recognition of certificates, facilitate smoother market access and support the growth of a thriving international hydrogen market.

Table 6.4 Overview of existing and planned regulatory frameworks and certification systems for hydrogen and hydrogen-based fuels

Government	Name	Purpose	Product	Status	Criteria
Australia	Guarantee of Origin certificate scheme	Voluntary	Hydrogen, hydrogen carriers	Under development	No eligibility criteria. The only requirement is to implement an emissions accounting methodology for the hydrogen produced.
Canada	Clean Hydrogen Investment Tax Credit	Regulatory, access to tax credits	Hydrogen, ammonia	Under development	Production below certain emissions intensity levels (<0.75, 0.75-2, 2-4 g CO_2-eq/g H_2). For ammonia, only one emissions intensity level is defined (<4 g CO_2-eq/g H_2-eq).
Denmark	Guarantee of Origin certificate scheme	Voluntary	Hydrogen, hydrogen-based fuels	Operational	Production from renewable electricity.
European Union	Renewable Energy Directive II	Regulatory, count against renewable energy targets	Hydrogen, hydrogen-based fuels	Operational (certification under development)	Production from renewable electricity (or grid electricity with <65 g CO_2-eq/kWh) meeting criteria on temporal and geographical correlation and additionality of renewable generation.
France	France Ordinance No. 2021-167	Regulatory, access to public support programmes	Hydrogen	Under development	"Low-carbon hydrogen": production with emissions intensity <3.38 g CO_2-eq/g H_2. "Renewable hydrogen": production with emissions intensity <3.38 g CO_2-eq/g H_2 and renewable sources.
Japan	Basic Hydrogen Strategy	Regulatory, access to public support	Hydrogen, hydrogen-based fuels	Under development	Production with emissions intensity <3.4 g CO_2-eq/g H_2.
Korea	Clean Hydrogen Certification Mechanism	Regulatory, access to public support	Hydrogen	Under development	Production with emissions intensity <4 g CO_2-eq/g H_2.
India	Green Hydrogen Standard for India	Regulatory, access to public support	Hydrogen	Under development	Production from renewable energy with emissions intensity <2 g CO_2-eq/g H_2.
Italy	Guarantee of Origin certificate scheme	Voluntary	Electricity and renewable gases (incl. hydrogen)	Operational	Production from renewable sources.
Netherlands	Guarantee of Origin certificate scheme	Voluntary	Hydrogen	Operational	Production from renewable electricity.
Spain	Guarantee of Origin certificate scheme	Voluntary	Renewable gases (incl. hydrogen)	Operational	Production from renewable electricity.

Government	Name	Purpose	Product	Status	Criteria
United Kingdom	Low Carbon Hydrogen Standard; Certification Scheme	Regulatory, access to public support	Hydrogen	Operational (certification under development)	Production with emissions intensity <2.4 g CO_2-eq/g H_2.
United Kingdom	Renewable Transport Fuel Obligation	Regulatory, access to public support	Hydrogen (use in transport)	Under development	Production from renewable energy (excluding bioenergy) with emissions intensity <4.0 g CO_2-eq/g H_2.
United States	Clean Hydrogen Production Standard; Tax Credit.	Regulatory, access to public support	Hydrogen	Under development	Production below certain emissions intensity levels (<0.45, 0.45-1.5, 1.5-2.5, 2.5-4 g CO_2-eq/g H_2) eligible for different levels of investment tax credits support.

Note: the table only includes certification systems established by governments, but some private certification schemes have also been developed or are under development. See more details in Towards hydrogen definitions based on their emissions intensity.

Operational and safety standards

Beyond environmental attributes, the creation of hydrogen value chains requires the development of a comprehensive portfolio of international standards dealing with safety, technology compatibility and operational issues.

The European Clean Hydrogen Alliance published in March 2023 a roadmap on hydrogen standardisation, providing a comprehensive overview of standardisation gaps, challenges and needs, and recommendations to streamline and accelerate the development of the standards required. The roadmap will help the European Commission to prepare a request to the European Standardisation Organisations for identified hydrogen standards.

Regarding safety standards, the European Hydrogen Safety Panel (EHSP) has updated its guidance on Safety Planning and Management in EU hydrogen and fuel cell projects. The aim is to support EU projects to incorporate state-of-the-art practices on hydrogen safety by integrating safety learnings, expertise and planning. In addition, the EHSP has worked on a new document with the statistics, lessons learned and recommendations from an analysis of the Hydrogen Incident and Accidents Database.[76]

There has also been progress on the development of standards for hydrogen operations, particularly for new hydrogen applications. SAE International, a standard-developing organisation based in the United States, announced that it is developing high-flow, general purpose prescriptive hydrogen fuelling protocols for the 35 and 70 MPa pressure classes, with a Technical Information Report expected in October 2023. The International Electrotechnical Commission published two new standards for performance testing of fuel cell/battery hybrid systems in excavators and power-to-methane energy systems based on solid oxide cells, and revised another two standards on safety and performance testing for fuel cell systems in trucks. The ISO has not published new standards since GHR 2022, but is currently working on five standards related to fuelling stations and protocols. In addition, in August 2023 China's National Standards Commission released standard guidelines covering safety and operational aspects of hydrogen production, storage, transport and end use.

A key area in which there has been no notable progress is in the development of hydrogen leakage measurement, reporting and verification protocols, and the development of methods and standards to detect and repair hydrogen leakage. Tapping into the full potential climate benefits of hydrogen technologies will require minimising hydrogen leakage (see Box 4.3 in Chapter 4 Trade and infrastructure), which in turn will depend on the development of such methods and standards.

[76] Access and download the full Hydrogen Incident and Accidents database set HIAD 2.0.

Regulations on infrastructure, permitting and other areas

Governments have also adopted regulations unrelated to the environmental attributes of hydrogen, in areas such as infrastructure or permitting.

With regards to infrastructure, the Australian government has extended the national gas regulatory framework to hydrogen and other renewable gases, allowing for a nationally consistent approach to gas pipeline regulation for all gases covered. At the end of 2021, the European Commission presented a proposal to revise EU gas market rules to facilitate the development of hydrogen infrastructure and regulate its use. In March 2023, the European Council took its position on this regulation and negotiations with the European Parliament have now begun, with the three institutions aiming to finalise these negotiations by the end of 2023. Also in Europe, in July 2023 Belgium passed its first Hydrogen Law to regulate the transport of renewable hydrogen through a network of pipelines, and introduced the function of a grid operator.

Regarding permitting, in the European Union the newly agreed Renewable Energy Directive includes regulatory provisions to fast-track permitting for renewable energy projects. EU member states are starting to take action on this front, with some – like Denmark, Italy and Portugal – including hydrogen in this streamlining effort.

In June 2023, the United Nations Economic Commission for Europe World Forum for Harmonization of Vehicle Regulations adopted amendments to the Global Technical Regulation No. 13, “Hydrogen and fuel cell vehicles” to improve test procedures, to extend the regulation to heavy vehicles, and to better reflect the state-of-the-art with respect to hydrogen vehicles. Acceptance of the draft amendments means that the first regulation for heavy-duty vehicles fuelled by hydrogen is now in place.

Annex

Explanatory notes

Projections and estimates

Projections and estimates in this *Global Hydrogen Review* 2023 are based on research and modelling results derived from the most recent data and information available from governments, institutions, companies and other sources as of July 2023. Updates will be included in the World Energy Outlook 2023 to be published in October 2023.

Terminology relating to low-emission hydrogen

In this report, low-emission hydrogen includes hydrogen which is produced through water electrolysis with electricity generated from a low-emission source (renewables, i.e. solar, wind turbines or nuclear). Hydrogen produced from biomass or from fossil fuels with carbon capture, utilisation and storage (CCUS) technology is also counted as low-emission hydrogen.

Production from fossil fuels with CCUS is included only if upstream emissions are sufficiently low, if capture – at high rates – is applied to all CO_2 streams associated with the production route, and if all CO_2 is permanently stored to prevent its release into the atmosphere. The same principle applies to low-emission feedstocks and hydrogen-based fuels made using low-emission hydrogen and a sustainable carbon source (of biogenic origin or directly captured from the atmosphere).

The IEA does not use colours to refer to the different hydrogen production routes. However, when referring to specific policy announcements, programmes, regulations and projects where an authority uses colours (e.g. “green” hydrogen), or terms such as “clean” or “low-carbon” to define a hydrogen production route, we have retained these categories for the purpose of reporting developments in this review.

Terminology for carbon capture, utilisation and storage

In this report, CCUS includes CO_2 captured for use (CCU) as well as for storage (CCS), including CO_2 that is both used and stored, e.g. for enhanced oil recovery or building materials, if some or all of the CO_2 is permanently stored. When use of the CO_2 ultimately leads to it being re-emitted to the atmosphere, e.g. in urea production, CCU is specified.

Scenarios used in this Global Hydrogen Review

This *Global Hydrogen Review* relies on two scenarios to track progress on hydrogen production and use:

- The Stated Policies Scenario (STEPS) explores how the energy system would evolve if current policy settings are retained. These include the latest policy measures adopted by governments around the world, such as the Inflation Reduction Act in the United States, but do not assume that aspirational or economy-wide targets will be met unless they are backed up with detail on how they are to be achieved.
- The Net Zero Emissions by 2050 Scenario (NZE Scenario) is a normative scenario that sets out a pathway to stabilise global average temperatures at 1.5°C above pre-industrial levels. The NZE Scenario achieves global net zero energy sector CO_2 emissions by 2050 without relying on emissions reductions from outside the energy sector.

Currency conversions

This report provides the stated values of programmes and projects in the currency stated in their announcement. These values, in many instances, are converted to US dollars for ease of comparison. The currency exchange rates used correspond to an average value for the year of the announcement based on OECD exchange rates.

Abbreviations and acronyms

ABS	American Bureau of Shipping
ADB	Asian Development Bank
AEM	anion exchange membrane
ALK	alkaline
ASU	air separation unit
ATR	autothermal reformer
AUD	Australian dollars
BECCS	bioenergy with carbon capture and storage
BEV	battery electric vehicle
BF	blast furnace
BOP	balance of plant
CAD	Canadian dollar
CAPEX	capital expenditure
CCfD	carbon contract for difference
CCGT	combined-cycle gas turbine
CCS	carbon capture and storage
CCU	carbon capture and use
CCUS	carbon capture, utilisation and storage
CF	capacity factor
CfD	contract for difference
CH_4	methane
CHP	combined heat and power
CO_2	carbon dioxide
COP	Conference of the Parties
DAC	direct air capture
DKK	Danish kroner
DME	dimethyl ether
DOE	Department of Energy (United States)
DRI	direct reduced iron
EBRD	European Bank for Reconstruction and Development
EHSP	European Hydrogen Safety Panel
EIB	European Investment Bank
EMDE	Emerging markets and developing economies
EOR	enhanced oil recovery
EPA	Environmental Protection Agency (United States)
EPC	engineering, procurement and construction
EPO	European Patent Office
ETF	exchange-traded fund
ETS	Emissions Trading Systems
EUR	Euro
FC	fuel cell
FCEV	fuel cell electric vehicles
FEED	front-end engineering and design
FID	final investment decision

FT	Fischer-Tropsch
FY	fiscal year
G7	Group of Seven
G20	Group of Twenty
GBP	British pound
GHG	greenhouse gases
GHR	gas-heater reformer
GWP	global warming potential
H_2	Hydrogen
H2I	the Hydrogen Initiative
HC	hydrocarbon
HD	heavy-duty
HRS	hydrogen refuelling stations
HT	high throughput
HVAC	high voltage alternating current
HVDC	high voltage direct current
HYDROM	Hydrogen Oman
ICE	Internal Combustion Engine
IDB	Inter-American Development Bank
INR	Indian rupees
IPCC	Intergovernmental Panel on Climate Change
IPCEI	Important Projects of Common European Interest
IPF	international patent family
IPHE	International Partnership for Hydrogen and Fuel Cells in the Economy
IRA	Inflation Reduction Act (United States)
IRENA	International Renewable Energy Agency
ISO	International Organization for Standardization
JPY	Japanese yen
KRW	Korean won
LCOA	levelised cost of ammonia
LCOH	levelised cost of hydrogen
LD	light-duty
LH_2	liquefied hydrogen
LNG	liquefied natural gas
LOHC	liquid organic hydrogen carrier
LPG	liquefied petroleum gas
MeOH	methanol
MoU	memorandum of understanding
N_2O	nitrous oxide
NASDAQ	National Association of Securities Dealers Automated Quotations
NG	natural gas
NH_3	ammonia
NO_x	nitrogen oxides
NZD	New Zealand dollars
NZE	Net Zero Emissions by 2050 Scenario

OPEX	operating expenditure
O&M	operational expenditures and maintenance costs
PEM	proton exchange membrane
PO_X	partial oxidation
PPA	power purchase agreement
PV	photovoltaic
RD&D	research, development and demonstration
RFNBO	renewable fuels of non-biological origin
SAF	sustainable aviation fuel
SHASTA	Subsurface Hydrogen Assessment, Storage, and Technology Acceleration
SMR	steam methane reformer
SOEC	solid oxide electrolyser
SOFC	solid oxide fuel cell
STEPS	Stated Policies Scenario
SUV	sports utility vehicle
TCP	Technology Collaboration Programme
TEN-E	Trans-European Networks for Energy
TRL	technology readiness level
TTF	Title Transfer Facility
USD	United States dollars
VC	venture capital
VRE	variable renewable electricity
WACC	weighted average cost of capital
ZETI	Zero-Emission Technology Inventory
ZEV	zero emission vehicle

Units

° C	degree Celsius
bar	metric unit of pressure
bbl	barrel
bcm	billion cubic metres
CO_2-eq	carbon dioxide equivalent
g	gramme
gallon	gallon (United States)
GJ	gigajoule
GJ_{coal}	gigajoule of coal
GJ_{NG}	gigajoule of produced natural gas
GW	gigawatt
GWh	gigawatt-hour
GW/yr	gigawatts per year
inch	inch
kg	kilogramme
kg CO_2-eq	kilogramme of carbon dioxide equivalent
km	kilometres
kt	kilotonnes

ktpa	kilotonnes per year
kW	kilowatt
kWe	kilowatt electric
L	litre
MBtu	million British thermal units
MPa	megapascal
Mt	million tonnes
Mt CO_2	million tonnes of carbon dioxide
Mt H_2-eq	million tonnes of hydrogen equivalent
MW	megawatt
MWh	megawatt-hour
Nm^3	normal cubic metre
Nm^3/h	normal cubic metres per hour
ppb	parts per billion
t	tonne
t CO_2	tonne of carbon dioxide
TWh	terawatt-hour

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Typeset in France by IEA - September 2023
Cover design: IEA
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Revised version, September 2023
Information notice found at: www.iea.org/corrections