HYDROGEN ECONOMY AND THE ROLE OF COAL

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PREFACE

This report has been produced by the International Centre for Sustainable Carbon (ICSC) for the International Energy Agency's (IEA) Coal Industry Advisory Board (CIAB). It is based on a survey and analysis of published literature, and on information gathered in discussions with interested organisations and individuals. Their assistance is gratefully acknowledged. It should be understood that the views expressed in this report are our own and are not necessarily shared by those who supplied the information, nor by our member organisations.

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The International Centre for Sustainable Carbon was established in 1975 and has contracting parties and sponsors from Australia, China, Italy, Japan, and South Africa.

The overall objective of the International Centre for Sustainable Carbon is to continue to provide our members, the IEA Working Party on Fossil Fuels and other interested parties with independent information and analysis on all coal-related trends compatible with the UN Sustainable Development Goals. We consider all aspects of coal production, transport, processing and utilisation, within the rationale for balancing security of supply, affordability and environmental issues. These include efficiency improvements, lowering greenhouse and non-greenhouse gas emissions, reducing water stress, financial resourcing, market issues, technology development and deployment, ensuring poverty alleviation through universal access to electricity, sustainability, and social licence to operate. Our operating framework is designed to identify and publicise the best practice in every aspect of the coal production and utilisation chain, so helping to significantly reduce any unwanted impacts on health, the environment and climate, to ensure the well-being of societies worldwide.

ABSTRACT

Hydrogen has a critical role to play in a clean energy transition to achieve net zero emissions (NZE). Global demand for hydrogen is set to increase rapidly and substantially from about 94 Mt/y in 2021 to more than 500 Mt/y by 2050. Meeting this demand, in particular, for low-emission hydrogen will require the rapid scaling up of its production capacity in a short period of time from less than 1 Mt/y clean hydrogen in 2022 to 32 MtH_2/y in 2030 in the IEA's Stated Policies Scenario.

Clean hydrogen can come from renewable-powered water electrolysis, coal gasification with carbon capture, utilisation and storage (CCUS) and natural gas steam methane reforming (SMR) with CCUS. Although coal gasification-based hydrogen production is the most carbon-intensive, the addition of CCUS could reduce CO_2 emissions substantially to a level comparable to that of natural gas SMR with CCUS. When the best available technologies are adopted, hydrogen production from coal gasification with CCUS can have life cycle environmental impacts similar to, or slightly larger than, the production of renewable hydrogen.

Developing and adopting renewable hydrogen faces several challenges. The high cost is the main barrier to hydrogen utilisation. There is also a requirement to invest in enough renewable energy to make the hydrogen, and in the infrastructure to store and transport the hydrogen produced. The global demand for clean hydrogen cannot be met by renewable hydrogen production, at least in the near to medium term. Therefore, low-emission hydrogen production from coal and gas with CCUS is essential to bridge the gap. Hydrogen production from coal gasification with CCUS costs significantly less than renewable electrolytic hydrogen. This report examines the regional variations in hydrogen demand and supply and the role of coal in helping to meet the demand for clean hydrogen. Producing low-emission hydrogen from coal with CCUS will be a low-cost option in regions with abundant coal, access to CO_2 storage and limited renewable energy availability. Particularly for emerging and developing economies that depend on coal and lack gas and oil resources, coal is indispensable in providing a secure, reliable energy supply and an affordable source for clean hydrogen production.

ACRONYMS AND ABBREVIATIONS

AEM	anion exchange membrane
APS	Announced Pledges Scenario, IEA
ATR	autothermal methane reforming
BEIS	Department for Business, Energy & Industrial Strategy, UK
Capex	capital expenditure
CCUS	carbon capture, utilisation and storage
DOE	Department of Energy, USA
DRI	direct reduction of iron
EC	European Commission
EHB	European Hydrogen Backbone
EOR	enhanced oil recovery
ETS	emissions trading scheme
EU	European Union
FCEV	fuel cell electric vehicle
FCHEA	Fuel Cell & Hydrogen Energy Association, USA
FCH JU	Fuel Cell & Hydrogen 2 Joint Undertaking
FFI	Fortescue Future Industries
FYP	Five-Year Plan
GHG	greenhouse gas
HESC	Hydrogen Energy Supply Chain Project
ICSC	International Centre for Sustainable Carbon
IEA	International Energy Agency
IRENA	International Renewable Energy Agency
LCA	life cycle analysis
LOHC	liquid organic hydrogen carrier
METI	Ministry of Economy, Trade and Industry, Japan
NETL	National Energy Technology Laboratory, USA
NHM	National Hydrogen Mission, India
NREL	National Renewable Energy Laboratory, USA
NZE	net zero emissions
Opex	operating costs
PEM	proton exchange membrane
PSA	pressure swing adsorption
PV	photovoltaic
R&D	research and development
RD&D	research, development, and demonstration
SMR	steam methane reforming
SOEC	solid oxide electrolysis cell
STEPS	Stated Policies Scenario, IEA
WEC	World Energy Council
WGS	water-gas shift

UNITS

Gtce	gigatonnes of coal equivalent (equivalent energy)
GW	gigawatts (electric power generation capacity)
kcal/kg	kilocalories per kilogram of coal
kJ/kg	kilojoules per kilogramme of coal
$ktCO_2/y$	thousand tonnes of CO_2 captured per year
kWh	kilowatt-hours (electric energy generation)
Mt	million tonnes
Mt/y	million tonnes per year
$MtCO_2/y$	million tonnes of CO_2 per year
MW	megawatts (electric power generation capacity)
MWh	megawatt-hours (electric energy generation)
TWh	terawatt-hour
tCO_2/y	tonnes of CO_2 per year
wt%	weight per cent

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EXECUTIVE SUMMARY

Hydrogen has a critical role to play in a clean energy transition to achieve net zero emissions (NZE). Over thirty governments have introduced hydrogen strategies and more have released roadmaps for developing a hydrogen economy. Many other countries have these activities underway. The development of a hydrogen economy is gathering momentum worldwide and many companies are alert to the potential business opportunities. Global demand for hydrogen is set to increase rapidly and substantially from about 94 Mt/y (2021) to more than 500 Mt/y by 2050. Meeting this demand, in particular that for low-emission hydrogen, will require the scaling up of production capacity in a short period of time from less than 1 Mt/y low-emission hydrogen in 2022 to 32 MtH_2/y in 2030 in the IEA's Stated Policies Scenario.

HYDROGEN FROM COAL CAN BE AS CLEAN AS RENEWABLE HYDROGEN

There are three established technical routes for hydrogen production: natural gas steam methane reforming (SMR), coal gasification, and water electrolysis. In 2021, SMR accounted for 62% and coal gasification for 19% of global hydrogen production, both without carbon capture utilisation and storage (CCUS). Only 0.7% was low-emission hydrogen from fossil fuels with CCUS and 0.04% was produced from water electrolysis. Hydrogen by-products from industrial processes made up most of the rest (18%).

Although coal gasification is the most carbon-intensive method of hydrogen production, the addition of CCUS with a capture rate of over 98% (technically feasible) would reduce the CO_2 emissions substantially from around 20 $kgCO_2/kgH_2$ to below 0.4–0.6 $kgCO_2/kgH_2$, less than natural gas SMR with CCUS. The carbon emissions intensity can be reduced further to achieve zero or negative emissions by cogasification of coal with biomass plus CCUS. While hydrogen production from electrolysis powered by renewables emits no CO_2, electrolysis is the most energy-intensive method requiring large amounts of electricity. Renewable energy required to power the electrolytic hydrogen production needs large areas of land to host the wind and/or solar PV generation capacity. The construction of solar and wind power plants relies on vast quantities of materials such as concrete, glass and steel. Production of steel and cement is difficult to decarbonise and contributes around 15% of global CO_2 emissions (2020). Some electrolysers also use critical materials and/or rare earth elements for catalysts. Production of these materials is energy and carbon-intensive, contributing to significant emissions of greenhouse gases (GHG). These issues will affect the life cycle carbon footprint of renewable hydrogen.

WITH BEST AVAILABLE TECHNOLOGIES, LOW-EMISSION HYDROGEN FROM COAL CAN HAVE LIFE CYCLE ENVIRONMENTAL IMPACTS SIMILAR TO RENEWABLE HYDROGEN, GIVING IT A ROLE IN THE CLEAN ENERGY TRANSITION.

Hydrogen has long been used in industry. It is currently delivered commercially by road as compressed or liquid hydrogen using tankers, trucks or by pipeline. Like natural gas, hydrogen can be transported by ship or barge either in liquid or gaseous form and demonstrations are underway. Hydrogen can also be converted to a hydrogen carrier such as ammonia which is more energy dense by volume than compressed or liquefied hydrogen and thus, is easier and cheaper to transport and to store. At its destination, the ammonia can be cracked to release the hydrogen or used directly as a fuel.

HYDROGEN PRODUCTION AND TRANSPORT TO SCALE UP DRAMATICALLY

For a viable hydrogen industry, hydrogen must be delivered to end users competitively and at scale. Today, production volumes are relatively small and hydrogen trade is mostly local, so delivery costs are relatively low. The projected growth in hydrogen demand means that hydrogen will need to become an internationally traded commodity and be transported long distances from production facilities to end users, raising the costs. Significant investment in infrastructure will be needed, as will new technologies, such as ships and barges to carry high-density hydrogen.

The challenges to establishing a global hydrogen supply chain include reducing costs, improving energy efficiency and building hydrogen delivery infrastructure while maintaining hydrogen purity and minimising hydrogen leakage.

DIVERSE SOURCES OF HYDROGEN ARE NEEDED

The projected renewable hydrogen capacity of many countries falls short of their targets, and the gap between existing hydrogen demand and projected production capacity of renewable hydrogen is even greater. Thus, diverse sources of hydrogen are required, to reflect the local resources available.

- For China and India, hydrogen production from coal gasification with CCUS will be vital to meet their increasing domestic demands.
- Japan, South Korea and some European countries will be major demand centres for low-emission hydrogen. But their limited domestic capability to produce hydrogen means they will need to import it.
- Some other countries can potentially produce low-emission hydrogen at a competitive cost but will have limited domestic demand, including Australia, Canada, Chile, Indonesia, Malaysia, the Middle East, Russia and South Africa. They may become major players in a global low-emission hydrogen trade.

International trade of low-emission hydrogen may evolve over time. Active collaboration is taking place between the potential importers and exporters to establish an international hydrogen supply chain and market. International trade in hydrogen is emerging and will increase, especially hydrogen in the form of ammonia for use as a clean fuel.

GLOBAL DEMAND FOR LOW-EMISSION HYDROGEN CANNOT BE MET BY RENEWABLE HYDROGEN

Meeting the short- to long-term demand targets for hydrogen is a huge challenge requiring rapid scaling up of hydrogen production capacity. The key challenges to address include:

- the large gap between the installed production capacity for renewable hydrogen and that required to meet governments targets;
- the insufficient renewable power generation capacity to support large-scale renewable hydrogen production whilst meeting the direct need for electricity;
- the limitations of the electrolyser production capacity; and
- supply issues of some key materials for electrolyser manufacture.

These factors mean that the global demand for low-emission hydrogen cannot be met by renewable hydrogen production, at least in the short to medium term. Therefore, hydrogen production from coal and gas with CCUS is essential to bridge the gap in meeting the demand.

A ROLE FOR COAL

Hydrogen production and use is an emerging industry. The cost of low-emission hydrogen (including production, transport and storage) is very high, which is the main barrier to its widespread application. Hydrogen produced from coal gasification with CCUS costs significantly less than renewable electrolytic hydrogen, and it can outcompete gas-based low-emission hydrogen, depending on where it is produced. This economic advantage will continue to 2030 or beyond.

HYDROGEN FROM COAL CAN IMPROVE THE ECONOMIC VIABILITY OF LOW-EMISSION HYDROGEN USE, ENABLE ITS EARLY AND WIDER DEPLOYMENT, AND BRIDGE THE TRANSITION TOWARDS RENEWABLE HYDROGEN USE IN THE LONGER TERM.

Table 1 compares the costs and environmental impacts of the three hydrogen production methods.

TABLE 1 COMPARISON OF HYDROGEN PRODUCTION METHODS

	Coal gasification with CCUS	SMR with CCUS	Water electrolysis
Energy intensity, kWh/kgH_2 (Zapantis, 2021; Patonia and Poudineh, 2020)	3.48	1.91	52.5–70.1
Life cycle GHG emissions, g$CO_{2\text{-eq}}$/MJ (HHV) (IEA, 2021b)	24*	23*	5–1
Water consumption, kgH_2O/kgH_2 (Coertzen and others, 2021)	70	18-44	60–90
Land use†, km^2 (Zapantis, 2021)	17	14	5750
Production cost, \$/kgH_2 (USDOE, 2020)	1.6	1.5–2.3	6–9.3

* with 95% CO_2 capture rate; † land requirement (excludes mining area) of a hydrogen plant with a capacity of 1.76 MtH_2/y

Although many new hydrogen projects will be located in industrial hubs with local end-users, international trade of low-emission hydrogen will develop to meet the global demand. Delivery infrastructure requirements will vary by region and market. The relative economics of hydrogen will depend largely on the resources available for its production, and delivery costs:

- For coal-dependent, large hydrogen-producing and consuming countries such as China and India, coal is the cheapest, indispensable source for hydrogen production.
- For importing countries such as Japan and South Korea low-emission hydrogen from coal offers a cost-competitive choice.
- For exporters such as Australia and Indonesia which have access to substantial CCUS sites, producing low-emission hydrogen and ammonia from coal can generate an income, providing importers with low-emission hydrogen at low and stable prices.

RENEWABLE HYDROGEN PRODUCTION IS RESOURCE INTENSIVE

The production of low-emission hydrogen using electrolysers, or coal or gas with CCS requires substantial resources such as land, water, electricity, coal, gas and CO_2 storage sites as well as raw materials, critical metals and rare earth elements.

Hydrogen production via electrolysis or coal plus CCUS both have substantial water requirements (*see* Table 1). However, electrolysers need higher quality water (high purity deionised water) than coal gasification. Although air cooling can reduce water consumption significantly, it does not work efficiently in hot weather where solar PV farms are often located. While some low-quality raw water and/or recycled wastewater can be used in a coal gasification plant after proper treatment, they may not be suitable for electrolysis. As renewable solar energy is often available in arid places, water shortages are more likely to be an issue for developing renewable hydrogen projects. On the other hand, many industries and settlements are established around coal mines, where coal-based hydrogen plants can benefit from the existing infrastructure, are a short distance from the coal and water supply and are near the end-users so logistics costs are minimised.

Water electrolysis is also energy intensive. Due to the low energy density of wind and solar power, a vast land area is needed to host the wind and/or solar PV generation capacity required for renewable hydrogen production (*see* Table 1). This may limit the development of renewable hydrogen. Fossil fuel hydrogen with CCS requires coal or gas, land for CO_2 pipelines and injection infrastructure, and suitable geological sites for the storage of CO_2. Where low-cost land or excellent renewable resources are not available, but coal and carbon storage sites are, low-emission hydrogen from coal with CCS will be the best option.

Hydrogen is an industry in its infancy, and its evolution may be complex and potentially disruptive. Currently, low-emission hydrogen (in particular renewable hydrogen) cannot compete with incumbent technologies and is still in the early stages of reaching the market. National policy frameworks for developing a hydrogen economy and related technologies should include a regional dimension and consider the availability of energy and feedstock resources, suitable land and water resources, proximity to the market and transport requirements, as well as social and environmental impacts. Supportive policies should promote hydrogen production that takes advantage of local resources and is economically viable. Different region-specific approaches are required to reach the ultimate goal of renewable hydrogen use and net zero emission. International cooperation is vital to establish a global value chain with reliable supplies of low-emission, cost-effective hydrogen. Hydrogen from coal gasification with CCUS can be as clean as hydrogen from natural gas reforming with CCUS and renewable electrolytic hydrogen, and it is cost competitive.

IN CERTAIN REGIONS AND MARKETS, COAL HAS A ROLE TO PLAY IN SUPPORTING THE DEVELOPMENT OF A HYDROGEN ECONOMY AND A CLEAN ENERGY TRANSITION TOWARD NZE.

Low-emission hydrogen from coal can offer a cost-competitive choice, supplementing other options in meeting the expected demand, not only the domestic demand in major hydrogen-consuming countries such as China and India but also in the global trade to provide importing countries with economically viable low-emission hydrogen.

1 INTRODUCTION

Climate change is already having visible effects globally and poses many risks to human beings and all other forms of life on Earth. It is widely recognised that the main driver of climate change is human activity, primarily from burning fossil fuels (coal, oil and gas) which releases carbon dioxide (CO_2), a greenhouse gas (GHG). To combat climate change, around 140 countries have announced, or are considering net zero targets, covering close to 90% of global emissions (CAT, 2022). Achieving net zero emissions (NZE) by mid-century will require deep decarbonisation of all sectors across the economy. The key technological solutions for decarbonisation include energy efficiency improvements, electrification with the electricity supplied by carbon-neutral sources, renewable energy, energy storage, hydrogen and hydrogen-based fuels, and carbon capture, utilisation and storage (CCUS).

Technologies such as renewable power, energy storage and CCUS can be applied to decarbonise various sectors and processes (such as power generation and industrial plants). Other sectors such as passenger vehicles, light aircraft and space heating can be decarbonised through electrification. However, sectors such as aviation and marine shipping cannot be electrified nor directly run on renewable power. In addition, heavy industrial sectors such as iron and steelmaking and some metallurgical and chemical processes are difficult to decarbonise because they need fossil fuels for both energy and processing. For these processes and various industrial applications that need high-intensity heat, hydrogen can substitute for coal, oil and natural gas for use as a fuel and/or a feedstock, reducing the total GHG emissions.

Hydrogen is both a chemical energy store and a fuel:

- it has an energy content of 120 MJ/kg, almost three times more than that of diesel or gasoline, and hence, can be used as an energy storage medium, enabling greater use of renewable energy by storing the energy where it is abundant and in excess supply, ready for use where and when it is needed;
- as a fuel, hydrogen is carbon-free and can replace fossil fuels for heat and power generation, transport, and in industrial processes. In particular, hydrogen or hydrogen-based fuels such as ammonia (NH_3) and methanol (CH_3OH) offer ways to promote the decarbonisation of a range of sectors such as aviation, maritime, long-haul transport, and heavy industries.

Therefore, hydrogen has a vital role to play in the clean energy transition and in achieving NZE. In addition, the use of low-emission hydrogen can help improve air quality and strengthen a nation's energy security. Key technological advances are needed to realise this potential. They should reduce the cost of production, storage, transport and use of hydrogen. The pay-off in making these advances should be considerable.

HYDROGEN HAS A VITAL ROLE TO PLAY IN THE CLEAN ENERGY TRANSITION AND IN ACHIEVING NZE. KEY TECHNOLOGICAL ADVANCES ARE NEEDED TO REALISE THIS POTENTIAL.

Hydrogen is the most abundant element in the universe. On Earth, hydrogen is present in vast quantities as a component of water in oceans, ice packs, rivers, lakes, and the atmosphere. As part of hydrocarbon compounds, hydrogen is also present in all animal and vegetable tissue as well as in fossil fuels. However, hydrogen is found almost exclusively in compounds and does not exist naturally as hydrogen (H_2) molecules in large quantities. Thus, hydrogen molecules have to be synthesised.

There are three main routes established for the manufacture of hydrogen at an industrial scale. These production processes can be powered by all types of energy source – coal, oil, natural gas, biomass, renewables and nuclear. The feedstock for hydrogen production can be coal, natural gas, biomass, or water (*see* Figure 1). The technology and energy source used, influence the cost and environmental impacts of each production route. The potential of hydrogen utilisation to reduce CO_2 emissions depends largely on how it is produced.

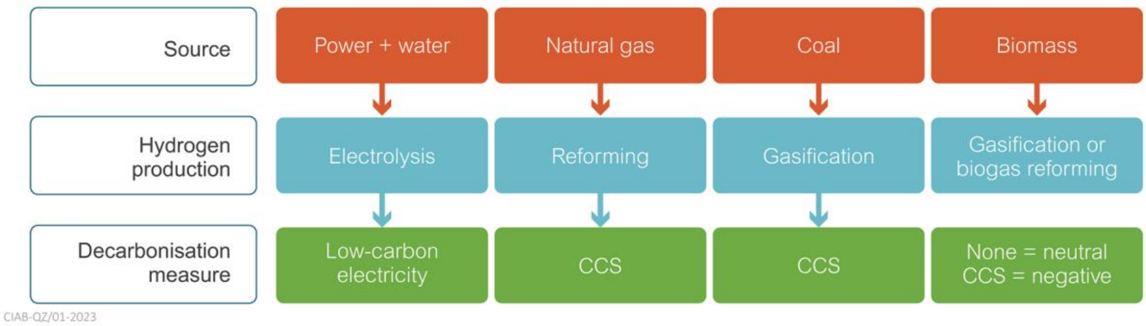


Figure 1 Hydrogen production methods (Kelsall, 2021)

Various names have been given to hydrogen to differentiate the source of its production, but there is no international agreement on the use of these terms. This study draws on the IEA's use of terminology (IEA, 2022a):

- renewable hydrogen is used to describe hydrogen produced from electrolysis of water powered by electricity generated from renewable sources.
- low-emission hydrogen includes hydrogen produced via electrolysis powered by electricity generated from a low-emission source (renewables or nuclear), biomass or fossil fuels with CCUS.
- unabated hydrogen is hydrogen from fossil fuel-based production without CCUS.

Global annual production of hydrogen is currently around 94 Mt, almost all (82%) based on natural gas or coal (especially in China) and mainly used in oil refining and fertiliser manufacture (*see* Figure 2). Low-emission hydrogen accounted for less than 1% of global hydrogen production in 2021 but has been boosted by the output from a new facility commissioned in January 2022 in China with a capacity to capture 0.7 $MtCO_2$/y.

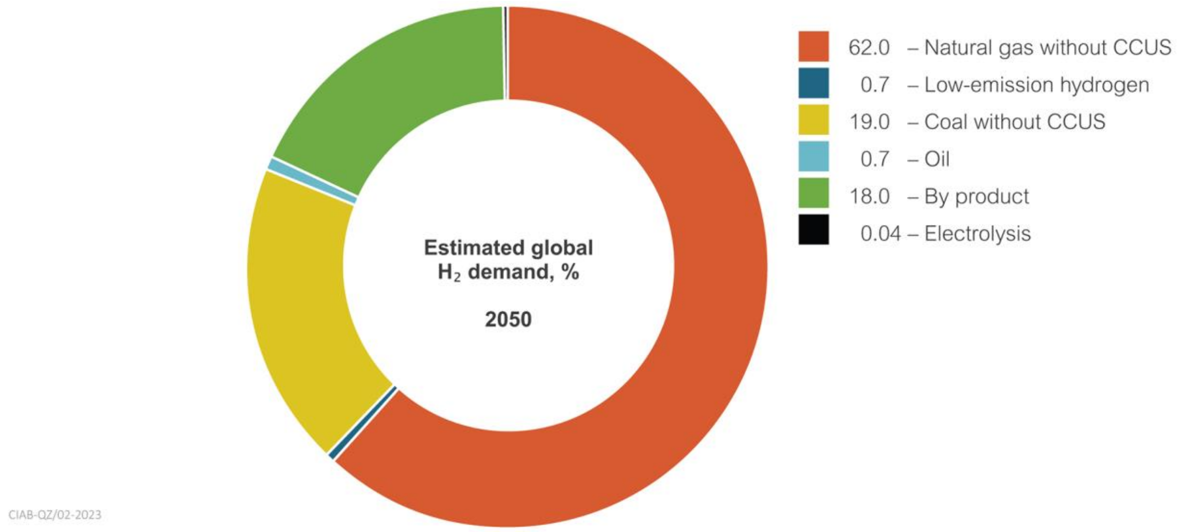


Figure 2 Sources for hydrogen production, 2021 (IEA, 2022a)

The pathway to NZE by 2050 requires greater use of hydrogen in existing applications and a significant uptake of hydrogen and hydrogen-based fuels for various new uses. Interest in hydrogen is gathering unprecedented momentum around the world. Global demand for low-emission hydrogen is set to increase rapidly and substantially. Meeting that demand is a challenge and requires rapid scaling up of production capacity.

This report considers how the demand can be met, including the role of coal. It begins with an overview of the status of national hydrogen development strategies and targets in Chapter 2. Chapter 3 provides brief descriptions of the existing and potential new uses of hydrogen and the projected demand for it. Chapter 4 reviews the main commercial pathways for hydrogen production, and compares the energy and carbon intensity, water consumption, and land and materials requirements of each production route. In Chapter 5, hydrogen supply issues including storage, transport and distribution, infrastructure, and safety concerns are discussed. Regional variations such as demand and supply, available resources, and the overall approach to hydrogen are examined, and the prospects for international hydrogen trade are assessed. Chapter 6 examines the challenges in meeting the future demand for low-emission hydrogen in terms of the gap between the electrolysis capacity in the project pipeline and the required capacity of installed electrolysers, the cost of hydrogen, and the implications of limitations to low-emission hydrogen production such as electrolyser production capacity, development in renewable power generation, critical materials supply, water stress and available land in some regions. The essential role of coal in helping to meet low-emission hydrogen demand to achieve NZE is identified.

2 HYDROGEN POLICIES

2.1 KEY MESSAGES

Hydrogen production is an established but infant industry. In order to achieve NZE mid-century all production and distribution technologies need to be available on their merits to assure energy system security and affordability as well as delivery of future emission reduction targets at least cost.

The goal of low-emission hydrogen is a common feature in all national hydrogen strategies, but they present diverse visions on how hydrogen might be produced. Some prioritise renewable hydrogen production such as the EU, Germany, Portugal and Spain, while others such as Australia, Japan, the UK and the USA explore both renewable and fossil fuel-based low-emission hydrogen (that is, they adopt a more technology neutral approach).

Almost all governments adopt a phased approach to integrate hydrogen into their energy systems. This generally comprises three stages:

- scaling-up and laying the market foundations (early 2020s);
- widespread adoption and market maturity (late 2020s to early 2030s); and
- full implementation of hydrogen as a clean energy vector (post-2030).

Not all the strategies set out long-term deployment targets or specific targets as expected progress within these phases. Where such targets exist, they are proposed as a vision or an aspiration, such as in Canada and Japan.

Virtually none of the targets are legally binding. In addition, most government targets and policies have focused on hydrogen production capacities and lack targets and policies for demand creation. This could result in a hydrogen value chain imbalance as an increase in supply may outpace growth in demand.

This is a dynamic policy area with frequent announcements of new policies and new targets. These factors create uncertainties in forecasts of future hydrogen demand.

2.2 NATIONAL HYDROGEN STRATEGIES AND TARGETS

Since the first Hydrogen Energy Ministerial meeting in Japan in 2018, hydrogen has become more important in many countries. Over thirty governments have introduced, or are formulating, hydrogen strategies, and more than 40 countries have released, or are about to release, hydrogen roadmaps for developing a hydrogen economy and related technologies (IEA, 2021a; WEC, 2021a; Tillier and Hieminga, 2021). Table 1 provides an overview of the status of national hydrogen strategies.

TABLE 1 THE DEVELOPMENT STATUS OF NATIONAL HYDROGEN STRATEGIES (MODIFIED FROM WEC, 2021A)			
	Policy discussions, official statements, initial demonstration projects	**Strategy in preparation**	**Strategy available**
Africa	Burkina Faso, Cape Verde, Mali, Nigeria, South Africa, Tunisia	Egypt, Morocco	
Asia-Pacific	Bangladesh, Hong Kong (China)	New Zealand, Singapore, Uzbekistan	Japan (2017), Australia (2019), South Korea (2019), China (2022), India (2023)
Europe	Bulgaria, Croatia, Denmark, Estonia, Finland, Georgia, Greece, Iceland, Latvia, Lithuania, Luxembourg, Malta, Romania, Serbia, Slovenia, Switzerland, Ukraine	Austria, Belgium, Poland, Sweden, Slovakia	EU (2020), France (2020), Germany (2020), Italy (2020), Netherlands (2020), Norway (2020), Portugal (2020), Spain (2020), Russia (2020), Czech (2021), Hungary (2021), UK (2021), Turkey (2023)
Central and South America & the Caribbean	Argentina, Bolivia, Costa Rica, Mexico, Panama, Paraguay, Peru, Trinidad and Tobago	Brazil, Uruguay	Chile (2020) Colombia (2021)
Middle East	Israel, UAE	Oman, Saudi Arabia	
North America		USA	Canada (2020)

In some countries, particularly some EU member states and Japan, the national strategies set ambitious targets which are supported by significant levels of government funding for research, development, and demonstration (RD&D), as well as financial aid for infrastructure development and access to end-use technologies. As a result, many companies are seeking to take advantage of hydrogen business opportunities. More detailed reviews of national hydrogen strategies, roadmaps and policies have been conducted recently by Kelsall (2021), IEA (2021a), and Tillier and Hieminga (2021).

2.2.1 Europe

In July 2020, the European Commission (EC) published the 'Hydrogen Strategy for a Climate-Neutral Europe', which includes a three-phase roadmap. The objective of Phase one, from 2020 to 2024, is to install at least 6 GW of renewable-powered electrolysers for 1 MtH_2/y production in the EU. In Phase two, from 2025 to 2030, the aim is to scale-up hydrogen production, distribution and use with the installation of at least 40 GW of electrolysers producing up to 10 MtH_2/y. Phase three, from 2030 onwards, has the objective to mature and use renewable hydrogen technologies in all sectors that are difficult to decarbonise. The EU aims for the share of hydrogen in the energy mix to be 13–14% by 2050, while the most optimistic scenario forecasts hydrogen's share to be up to 24% by 2050 (Tillier and Hieminga, 2021). As a consequence of the Russia-Ukraine conflict, the EU raised the target for hydrogen in the bloc's energy mix to 20 MtH_2/y by 2030, 50% of which is to be met by imports (EC, 2022).

Individual EU countries have their own approaches and hydrogen targets. For example, Germany, France and Italy have announced specific budgets to achieve 5, 6.5 and 5 GW electrolyser capacity by 2030, respectively. The development of hydrogen capacity in the Netherlands (3–4 GW by 2030) and Spain (4 GW by 2030) will be financed by investment from the private sector with a modest government budget and EU funds.

While the EU and its member states plan to rely mainly on renewable hydrogen, other countries are exploring the use of low-emission hydrogen to achieve policy goals. A key focus of the *UK Ten-point Plan for a Green Industrial Revolution* is to drive the growth of low-emission hydrogen for use across the economy with the aim of reaching 5 GW hydrogen production capacity by 2030 (HM Government, 2021). Scotland has gone further with targets of 5 GW of low-emission hydrogen by 2030, and at least 25 GW by 2045 (Scottish Government, 2020). As part of new plans to gain energy independence in response to the Russia-Ukraine conflict, the UK Government has raised its ambition for domestic low-emission hydrogen production from 5 GW to 10 GW by 2030 with half of it to be renewable hydrogen (Heynes, 2022).

2.2.2 Asia-Pacific

Japan was the first country to adopt a national hydrogen framework and has been a leading player in developing hydrogen technologies. The Sixth Strategic Energy Plan (SEP) published in October 2021 set targets of 1% of hydrogen and ammonia in both the primary energy mix and the electricity supply mix in 2030, consistent with the country's 2030 goal of reducing GHG emissions by 46% from 2013 levels (METI, 2021). Japan also plans to have 200,000 fuel cell electric vehicles (FCEVs) on the road by 2025 and 800,000 by 2030, together with 320 hydrogen refuelling stations by 2025 and 900 by 2030 (Tillier and Hieminga, 2021). Japan's hydrogen roadmap promotes the use of hydrogen and ammonia in Japan in thermal power plants and as a transport fuel. It aims to reduce hydrogen costs to ≤3 \$/kgH_2 by 2030 and to ≤2 \$/kgH_2 by 2050 to promote the competitiveness of the economy. Japan's plan has considerable government support in developing hydrogen technologies and infrastructure. The Japanese Ministry of Economy, Trade and Industry (METI) invested over one billion US dollars in the financial year 2022-23 to accelerate the use of hydrogen and ammonia, including RD&D of ammonia-coal cofiring at an existing coal-fired power plant, and fuel cell and water electrolysis technology at ports and factories.

South Korea seeks to become a global leader in producing and deploying FCEVs and large-scale stationary fuel cells for power generation. It plans to use renewable hydrogen and ammonia as a key power generation fuel to reduce demand for coal and natural gas for electricity production (Lee, 2021), and to use hydrogen to power 10% of the country's cities, counties and towns by 2030 and 30% by 2040 (IRENA, 2022a). The government expects hydrogen to become the country's largest single energy carrier in 2050, accounting for one-third of total energy consumption. It also aims to have 200,000 FCEVs by 2025 as part of its Green New Deal. In particular, South Korea aims to be a global leader of hydrogen-powered vehicles and is focused on potential export markets. Both Japan and South Korea are actively exploring hydrogen imports with various supplier countries such as Australia and the Gulf States.

As a major energy exporter, the Australian strategy places more emphasis on hydrogen production and export while also considering its domestic use in transport, particularly heavy-duty and long-distance, and the large-scale production of clean ammonia. Australia has identified Singapore, Japan, China and South Korea as export markets, and recognises that it needs to be able to produce hydrogen at less than 2 $/kg to be competitive in the Asia-Pacific market (Tillier and Hieminga, 2021).

China issued its first hydrogen roadmap in 2016, which led to it having the world's third-largest FCEV fleet and becoming a pioneer in developing fuel cell trucks and buses. Hydrogen has been recognised as one of the six industries of the future in China's 14th Five-Year Plan (2021-2025). In March 2022, the Chinese government released its Medium- and Long-Term Plan for the Development of the Hydrogen Energy Industry (2021-2035). The Plan sets out a national strategy with a phased approach to developing a domestic hydrogen industry and mastering technologies and manufacturing capabilities (NDRC, 2022). It focuses on lowering costs and building capabilities to achieve renewable hydrogen production of 100,000–200,000 tH_2/y by 2025 and enable a reduction of CO_2 of 1–2 Mt/y. China prioritises self-sufficiency by building out a domestic supply chain, from manufacturing electrolysers to generating end-user demand, with less importance placed on hydrogen imports.

India launched a National Hydrogen Mission (NHM) in August 2021, to articulate the government's vision, intent and direction for hydrogen and to outline a strategy (IEA, 2021a). The NHM will also explore policy actions to support the use of hydrogen as an energy vector and develop India into '*a global hub for green hydrogen production and export*'. The first policy actions are underway, as the government announced the adoption of auctions in 2021 for renewable hydrogen production and mandatory quotas for using renewable hydrogen in user industries. According to the proposal, it will be mandatory from 2023/24 for refineries to meet 10% of their hydrogen demand with renewable hydrogen, increasing to 25% in the following five years. Fertiliser producers will need to meet 5% of their demand with renewable hydrogen in 2023/24, increasing to 20%. This proposal is expected to be extended to the steel industry in the near future.

2.2.3 Americas

The USA started an Energy Hydrogen Programme in the mid-2000s, which has included research and development (R&D) on hydrogen production, infrastructure, storage, fuel cells, and other applications across many sectors. Several government-funded programmes are available to support the uptake and scale-up of hydrogen technologies including an $8 billion Hydrogen Hub Plan, $1 billion for R&D, and the $500 million Hydrogen Supply-Chain Initiative (DNV, 2022). The focus of both Canada and the

USA is on advancing production hubs for fossil fuel-based hydrogen with CCUS and electrolysis based on renewables or nuclear power. End-use plans include low-emission hydrogen use in industrial processes, road transport, and grid balancing.

Canada aims for global leadership in supply of low-emission hydrogen and to produce 25 MtH_2/y by 2050 with a 30% share of hydrogen in end-use energy with more than 50% hydrogen in natural gas and dedicated hydrogen pipelines (Government of Canada, 2020). Canada's target is to reduce the cost of low-emission hydrogen to 1.5–3.5 $/$kgH_2$.

Both Chile and Columbia aim to develop local supply and demand while seeking to become global hydrogen export hubs (WEC, 2021a; DNV, 2022). Chile's target is to have 5 GW of electrolyser capacity under development by 2025, and 25 GW by 2030 with committed funding. In the longer term, Chile expects that renewable hydrogen will become attractive to overseas markets. Colombia plans for 40% of industrial hydrogen consumption to be fossil fuel-based low-emission hydrogen by 2030. However, the principal focus is on exporting hydrogen.

3 DEMAND FOR HYDROGEN

3.1 KEY MESSAGES

Hydrogen has traditionally been used as feedstock and reagent in oil refining, chemicals production and steelmaking. It can also be used as an energy source, replacing fossil fuels in transport, the power sector, space heating and many industrial processes.

The pathway to NZE requires increased use of hydrogen in existing applications and a significant uptake of hydrogen for new applications, especially for energy purposes.

Creating demand for low-emission hydrogen is critical to its widespread production and use.

Scenario analysis suggests demand for hydrogen will begin to pick up from 2030; it will then accelerate rapidly reaching up to ten times the current level by 2050.

- This increase in demand will become significantly higher with increasing climate change mitigation ambitions, as will the uncertainty in the actual demand for hydrogen due to unknowns about the pace and shape of the energy transition.
- There are also regional variations in future total and sectoral demand for hydrogen driven by different government policy approaches and local factors.

Despite these uncertainties, there will be a substantial rise in future hydrogen demand globally. Europe and Japan both have ambitious targets and are expected to be major demand centres for low-emission hydrogen.

While hydrogen is a versatile energy carrier and fuel the major barrier to its widespread deployment and use is cost. Addressing this will require substantial public and private investment in infrastructure and technology development.

3.2 APPLICATIONS FOR HYDROGEN

Hydrogen is a versatile energy carrier and can be used in many applications as categorised below:

- industrial processes such as oil refinery, ammonia and methanol synthesis, and DRI;
- transport including road, rail, shipping and aviation;
- power sector for flexible power generation, off-grid power supply, and large-scale and seasonal energy storage;
- power-to-fuel for production of fuels or chemicals using renewable energy; and
- industrial, residential and commercial heating.

Currently, hydrogen is mainly used in refining and industry as a feedstock or reagents. Approximately 44% of hydrogen produced each year is used for the removal of sulphur from refined oil products and heavy oil upgrading in refineries (IEA, 2021a). Around 50% of hydrogen is used as feedstock for the production of chemicals; roughly three-quarters of this is for ammonia production and one-quarter for methanol. The remaining hydrogen is used in the direct reduction of iron (DRI) for steelmaking, as well as in glass, electronics, food, and other chemical and petrochemical industries.

Hydrogen can replace fossil fuel as feedstock or as fuel in other industrial processes that require high intensity heat such as smelting and cement production and it can facilitate different types of chemical reactions such as the production of liquid fuels and chemicals by hydrogenation of captured CO_2 which is potentially a huge market. Several pilot projects are ongoing to demonstrate hydrogenation-based carbon utilisation technologies (Zhu, 2018; Li, 2022).

In the transport sector, hydrogen has started to be used in the deployment of FCEVs in the last decade. In the power sector, there are pilot projects underway where hydrogen is injected into gas grids for home heating and where it is cofired with fossil fuels for electricity generation.

Hydrogen or hydrogen-based fuel, such as ammonia and methanol, can also be used as an energy storage medium for grid balancing and energy storage. However, the adoption of hydrogen for new applications has been slow due to various technical and infrastructure challenges. Hydrogen use in transport, for example, is less than 20 kt/y, or 0.02% of total hydrogen consumption (IEA, 2021a). A review of the use of ammonia as a fuel in the clean energy transition has recently been published by the International Centre for Sustainable Carbon (ICSC) (Zhu, 2022).

3.3 DEMAND FOR HYDROGEN

3.3.1 Global demand

Global hydrogen demand was around 94 Mt in 2021, a 5% increase on the previous year (IEA, 2022a). The pathway to net zero emissions requires the increased use of hydrogen in existing applications and a significant uptake of hydrogen in new ones, especially in the energy sector either directly, or in the form of hydrogen-based fuels. This would increase hydrogen demand substantially. The scale of future uptake of hydrogen will be largely influenced by many factors including policies, decarbonisation goals, costs, development of hydrogen technologies, and competition from rival technologies. Several forecasts have been made of potential future global demand for hydrogen under various scenarios. These forecasts vary significantly between the scenarios due to differing underlying assumptions (*see* Table 2). The hydrogen demand projections from some major studies are given in Table 2 and are compared in Figure 3.

TABLE 2 FORECAST OF HYDROGEN DEMAND BY 2050, Mt/y

	Scenario		H_2 in final energy demand in 2050, %
IEA (2021a)	APS*	NZE†	
	250	530	13 (in NZE scenario)
Hydrogen Council (Hydrogen Council and McKinsey, 2021)	660		22
IRENA (2022b)	614		12
BloombergNEF (BNEF, 2021)	§Grey scenario	**Green scenario	
	190	1318	22 (in Green Scenario)
DNV (2022)	320		na‡

* Announced Pledges Scenario based on the government targets set out in national hydrogen strategies and roadmaps
† NZE by 2050 Scenario
‡ not available
§ Grey scenario: achieving NZE via renewable and low-emission electricity and hydrogen
** Green scenario: a net-zero pathway via renewable electricity and hydrogen use

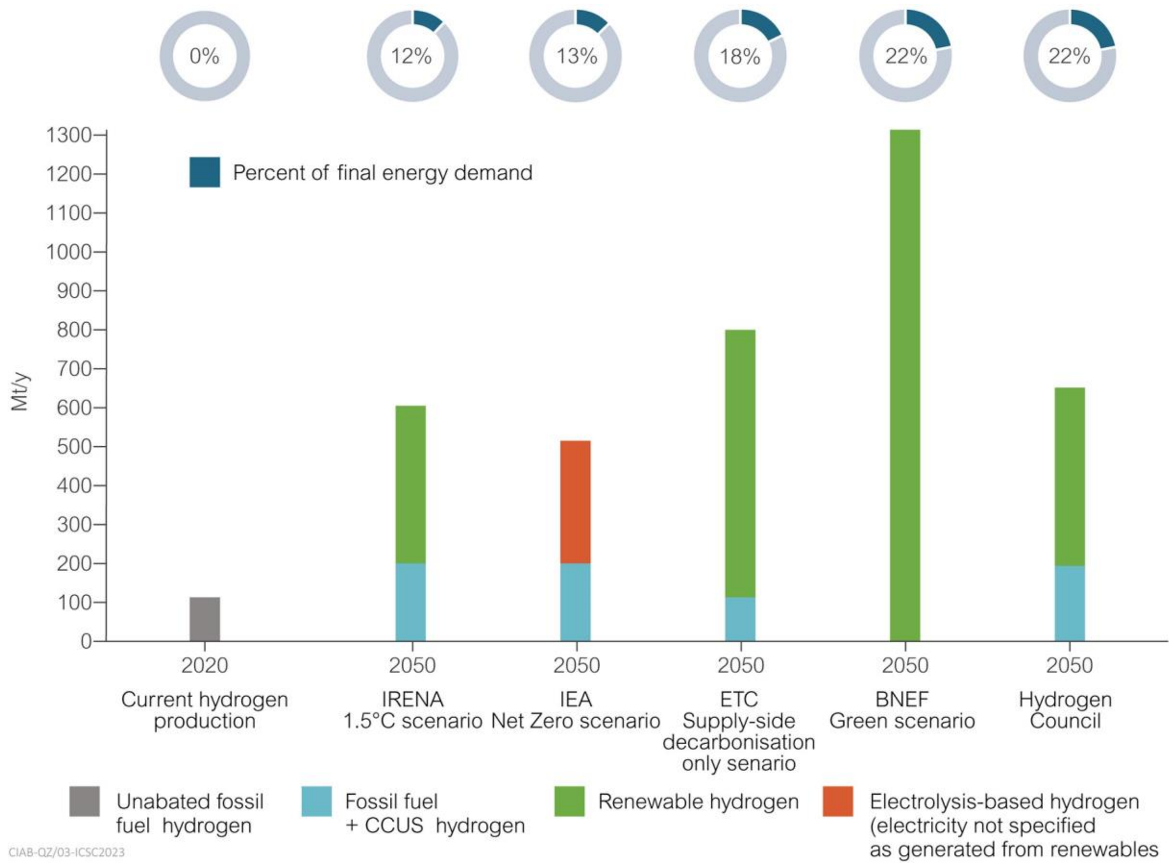


Figure 3 Estimates for global hydrogen demand in 2050 in various scenarios (modified from IRENA, 2022b)

The World Energy Council (WEC, 2021b) analysed global hydrogen demand projections from eight different sources, with a total of thirteen scenarios to show overall patterns of demand development.

Depending on ambitions to mitigate climate change, the scenarios are divided into the following three groups:

- low ambition trajectory with a >2.3°C global warming;
- medium ambition trajectory with 1.8–2.3°C global warming; and
- high ambition trajectory with <1.8°C global warming.

As the specifics of each scenario vary, the standard deviation for each trajectory was calculated to show the upper and lower spread from the scenario average and the results are shown in Figure 4. Although there is a wide range for each demand trajectory, some general trends can be observed. First, the uptake of hydrogen will start to grow from 2030 and will accelerate rapidly in the following decades. Second, there will be a substantial rise in hydrogen demand in all scenarios. Finally, the increase in future demand will be significantly higher with increasing climate change mitigation ambitions, as will the uncertainties in the actual demand for hydrogen.

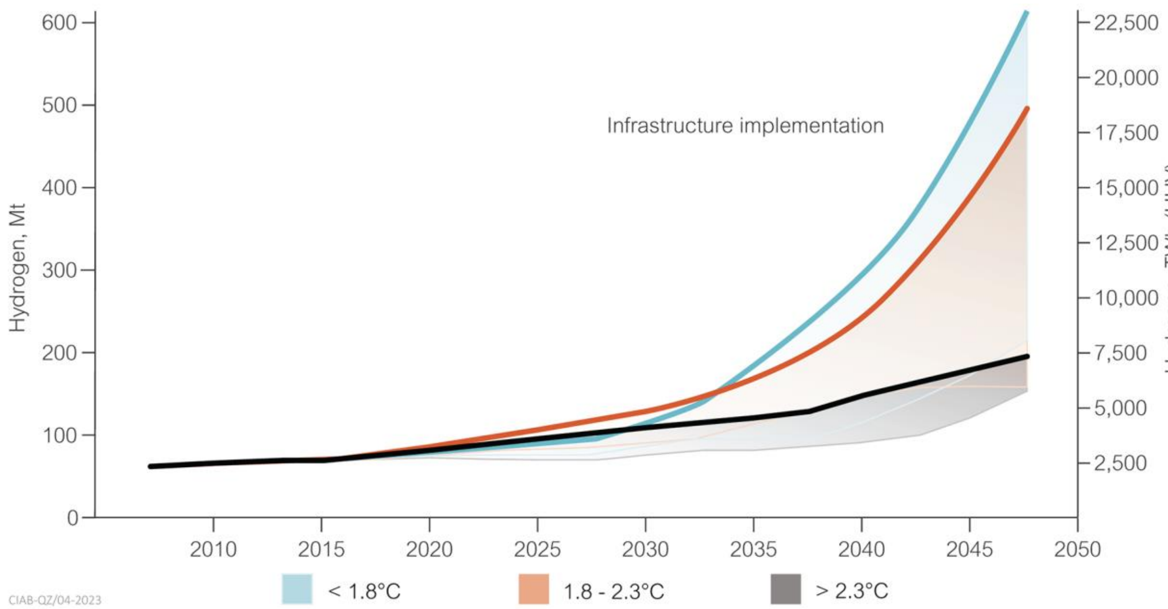


Figure 4 Range of forecasts of hydrogen demand to 2050 (WEC, 2021b)

3.3.2 Regional demand

Figure 5 illustrates hydrogen demand by region in 2020. Due to the different approaches taken by individual countries and local factors, there are wide variations in future total and sectoral demand for hydrogen. A recent analysis of hydrogen demand by Kelsall (2021) is available from the International Centre for Sustainable Carbon (ICSC).

Figure 5 Regional demand for hydrogen in 2020 (Mt/y) (IRENA, 2022b)

China is the world's largest hydrogen user and produced 33.42 Mt hydrogen in 2020 (Sheng, 2022). Most of the hydrogen is used in the refining and chemical sectors. In China, almost all developments of new uses for hydrogen have focused on transport. China has now the world's third-largest FCEV fleet and leads in the deployment of fuel cell trucks and buses. According to the statistics of the China Automobile Association, China produced 1777 FCEV in 2021 and sold 1586, which was an annual increase of 48.2% and 34.7% respectively (NEEC, 2022).

China is the largest producer of methanol, ammonia, and steel, three sectors in which low-emission hydrogen could play a significant role. China is developing technologies for decarbonising chemical and steelmaking processes using hydrogen in demonstration projects that are planned or under development (IEA, 2021a). There is also interest in China in using ammonia as fuel. Recent tests of ammonia-coal cofiring for power generation have been successful, which could provide China with an alternative approach to decarbonising its coal power generation sector. According to a study by China Hydrogen Alliance Research Institute, to achieve carbon neutrality by 2060, hydrogen will play a pivotal role in China's heavy industry, medium and heavy transport, building heating and other sectors that are difficult to decarbonise. Demand for hydrogen in China could reach 130 Mt/y by 2060, accounting for 20% of its final energy consumption (Sheng, 2022).

Owing to its large refining and chemical sectors, the **USA** is already one of the largest producers and consumers of hydrogen, using over 11 MtH_2/y, accounting for 13% of global demand (IEA, 2021a). Two-thirds of the hydrogen is used in refining, and most of the rest is used for ammonia production. The USA has been a strong supporter of hydrogen as an energy vector and an advocate for the adoption of hydrogen technologies. The Fuel Cell & Hydrogen Energy Association (FCHEA) of UDA analysed hydrogen as a solution to the energy challenges facing the USA to 2030 and beyond. It found that in the ambitious scenario, hydrogen could support 14% of US final energy demand by 2050, equivalent to over 2468 TWh/y, with a further potential for 11 MtH_2/y in additional uses such as synthetic aviation fuels and ammonia fuels for shipping. Hydrogen in transport applications would be the largest sector, followed by existing industrial feedstock applications. By 2030, the hydrogen economy in the USA could generate revenue of 140 billion $/y, potentially growing to 750 billion $/y by 2050. Figure 6 shows the hydrogen demand in the USA forecast by the FCHEA.

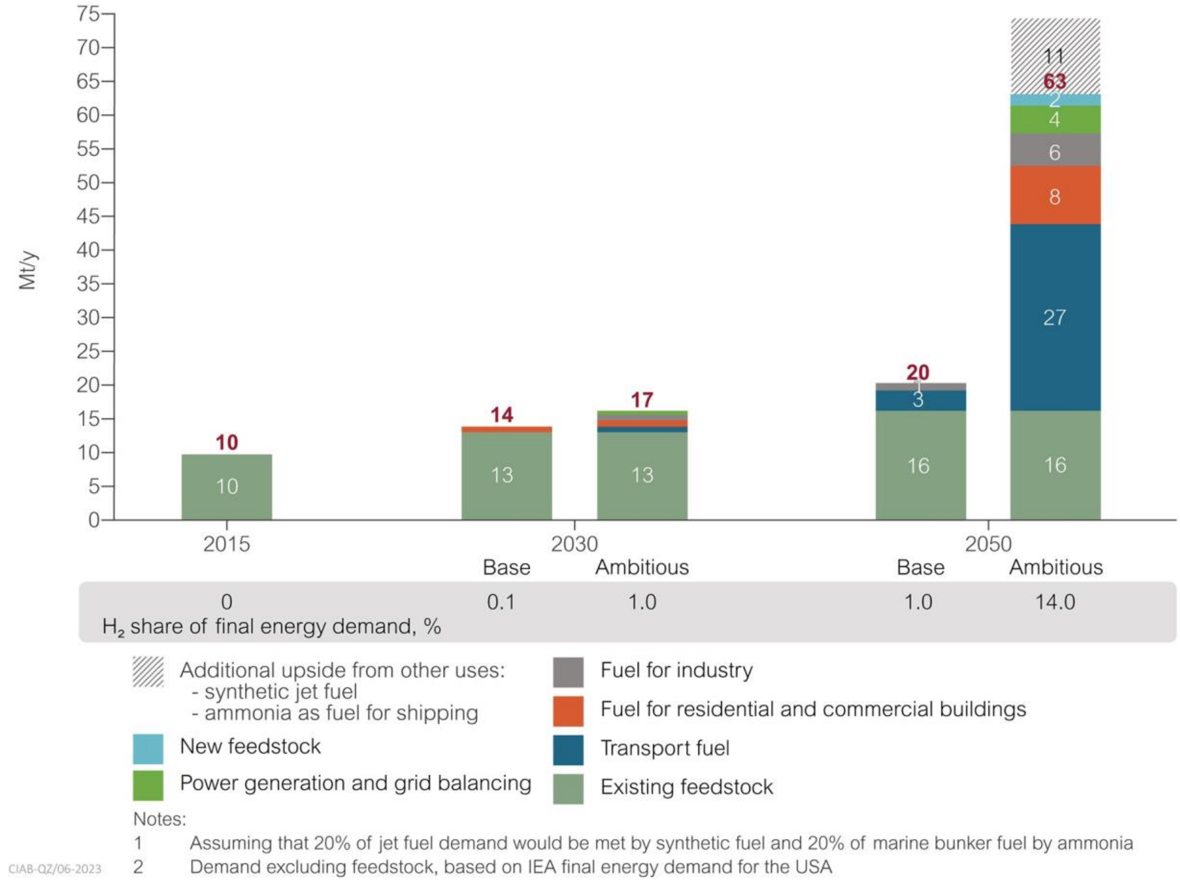


Figure 6 Forecast estimated total and sectoral hydrogen demand in the USA (FCHEA, 2020)

The **Middle East** was the third largest consumer of hydrogen in 2020 at around 11 Mt (IEA, 2021a). Hydrogen is used in oil refining, DRI production, chemicals and other industries. Looking out to 2030, Oman, Saudi Arabia and the United Arab Emirates (UAE) in particular, have ambitious plans to produce low-emission hydrogen from gas with CCUS and/or from electrolysis for export to Europe and the Asia-Pacific, and for domestic use. High solar yields and abundant land provide opportunities for production of renewable hydrogen. Natural gas reserves, existing petroleum industry infrastructure and suitable geo-storage offer opportunities for hydrogen produced from natural gas with carbon capture.

India consumed over 7 Mt of hydrogen in 2020, with 45% used for refining, 35% for chemicals and almost 20% for iron and steel (IEA, 2021a). India is the world's largest producer of steel using the DRI route, consuming one-quarter of global hydrogen demand for this end use. Also, India is the world's largest importer of ammonia for fertiliser production. With a growing population and greater prosperity, increased amounts of ammonia are required for fertiliser production to produce more food and more steel is needed in the construction of more infrastructure. Consequently, hydrogen use in India is expected to rise substantially in the next decade. In the IEA's APS, hydrogen demand in India grows to nearly 11 Mt/y by 2030, with DRI-based steelmaking accounting for around 30% of this increase.

The **EU** produced and used nearly 7 MtH_2 in 2020; the refining (3.7 Mt) and chemical sectors (3.0 Mt) were the main consumers (IEA, 2021a). The Fuel Cells and Hydrogen 2 Joint Undertaking (FCH JU, 2019) analysed the role that hydrogen could play in Europe and the results are shown in Table 3. It concluded that hydrogen would be an essential element in the energy transition and could account for 24% of final energy demand in the EU by 2050. Transport, and heating and power for buildings will be the major consumers of hydrogen. As discussed in Section 2.2.1, in response to the Russia-Ukraine conflict, the EU's ambition was increased in 2022 which will lead to increased demand for low-emission hydrogen in the short to medium term.

TABLE 3 FORECAST OF TOTAL AND SECTORAL HYDROGEN DEMAND IN THE EU (FCH JU, 2019)

<table>
<tr><th rowspan="2">Sector</th><th>2015</th><th colspan="2">2030</th><th colspan="2">2050</th></tr>
<tr><th>Base, TWh</th><th>Business as usual scenario, TWh</th><th>Ambitious Scenario, TWh</th><th>Business as usual scenario, TWh</th><th>Ambitious Scenario, TWh</th></tr>
<tr><td>Existing industry feedstock</td><td>325
(10 MtH_2/y)</td><td>427</td><td>427</td><td>391</td><td>391</td></tr>
<tr><td>New industry feedstock</td><td>0</td><td>0</td><td>62</td><td>1</td><td>257</td></tr>
<tr><td>Industrial energy</td><td>0</td><td rowspan="4">54</td><td>8</td><td>53</td><td>237</td></tr>
<tr><td>Heating and power for buildings</td><td>0</td><td>33</td><td>207</td><td>579</td></tr>
<tr><td>Transport</td><td>0</td><td>70</td><td>85</td><td>675</td></tr>
<tr><td>Power generation buffering</td><td>0</td><td>65</td><td>43</td><td>112</td></tr>
<tr><td>Total hydrogen demand</td><td>325</td><td>481</td><td>665</td><td>780
(25 MtH_2/y)</td><td>2251
(~68 MtH_2/y)</td></tr>
<tr><td>Share of hydrogen in final energy demand, %</td><td>2.3</td><td>4.2</td><td>5.8</td><td>8.4</td><td>24.2</td></tr>
</table>

Canada produced and used around 3 Mt H_2 in 2020 (IEA, 2021a). Canada may not see a significant rise in domestic demand for hydrogen, but it has an ambitious goal to become a major exporter of low-emission hydrogen and hydrogen-based fuels. Therefore, hydrogen production in Canada is expected to increase.

In **Japan**, hydrogen demand was nearly 2 Mt in 2020, 90% of which was for refining and ammonia production made up the rest (IEA, 2021a). Japan's Green Growth Strategy, announced in June 2021, has a target to expand hydrogen use to 3 Mt in 2030 and 20 Mt (almost a seven-fold increase) in 2050 (METI, 2022). In addition, the Road Map for Fuel Ammonia published by METI in 2021 promotes the use of ammonia as fuel in Japan in shipping and for cofiring in coal power plants to reduce their carbon intensity, as they are critical to Japan's security of electricity supply. Currently, a 20% ammonia-coal cofiring demonstration project is under development at a commercial coal power plant in Japan. Using higher proportions of ammonia in power generation is also gaining traction in Japan where gas turbines that run on ammonia and ammonia burners for coal boilers are being developed. Some electricity generators in Japan plan to start cofiring ammonia at existing power plants in 2030. Japan expects to import 3 Mt/y of clean ammonia by 2030.

Over 1.8 Mt of hydrogen was produced and used in **South Korea** in 2020, practically all for refining and petrochemical processes (IEA, 2021a). South Korea led FCEV deployment in 2020 with over 10,000 cars and 50 buses on the road; the aim is to increase this total to 200,000 FCEVs by 2025. According to its Hydrogen Roadmap, the South Korean government plans to expand its focus to include hydrogen ships, trains and drones once the road vehicle market has matured.

The South Korean government also plans to use hydrogen to power 10% of its cities and towns by 2030 increasing to 30% by 2040. It expects hydrogen to account for one-third of the country's total energy consumption in 2050 (IRENA, 2022a). In addition, the government has targeted the use of ammonia as a fuel to reduce the demand for coal and natural gas for electricity production (Lee, 2021). It plans to start commercialising ammonia cofiring technologies from 2030, raising the portion of ammonia fuel in power generation to 3.6%, or 22.1 TWh. As a result, hydrogen demand in South Korea will increase significantly, especially the demand for hydrogen as a clean fuel. In the IEA's (2021a) APS, South Korea will consume 1.9 MtH_2/y by 2040 to generate 33 TWh of power.

4 HYDROGEN PRODUCTION AND REQUIREMENTS

4.1 KEY MESSAGES

There are three main technological routes for hydrogen production: natural gas reforming, coal gasification and water electrolysis:

- in 2021, natural gas steam methane reforming (SMR) accounted for 62% and coal gasification for 19% of global production, both without CCUS;
- only 0.7% was produced from fossil fuels with CCUS and 0.04% from water electrolysis; and
- hydrogen by-products from industrial processes make up most of the rest (18%).

Coal gasification-based hydrogen production is the most carbon intensive production pathway, emitting around twice as much CO_2 as that of natural gas SMR, so the only possible NZE pathway is to add CCUS.

Adding CCUS to fossil fuel-based hydrogen production would reduce CO_2 emissions from both coal gasification and natural gas SMR to comparable levels.

Electrolysis is the most energy-intensive method of hydrogen production. Although it has a high water consumption similar to the coal gasification-based method, the process requires significantly higher water purity.

Although hydrogen production from renewable powered electrolysers emits no CO_2, electrolysers driven by grid electricity using a large proportion of fossil-fuelled generation would result in higher carbon intensities than directly using natural gas or coal for hydrogen production. The necessary solution is to add low emission electricity (from renewables or nuclear).

Solar and wind power plants needed to run renewable hydrogen production require large areas of land and vast quantities of materials such as concrete, glass and steel. Some electrolysers also need critical materials and/or rare earth elements for the catalysts. Production of these materials needs to grow significantly but they are energy and carbon intensive, contributing to significant emissions of greenhouse gases.

When best available technologies are adopted, low-carbon hydrogen from fossil fuel could have a similar carbon footprint to electrolysis with renewables.

Hydrogen can be produced via different technical routes with varying efficiencies and environmental impacts. This chapter provides an overview of the main commercial pathways for hydrogen production. The energy and carbon intensity, water consumption, and land and materials requirements of hydrogen produced from different technological routes are compared.

Hydrogen is present in vast quantities on Earth as part of water and hydrocarbon compounds such as those contained in fossil fuels and biomass. By applying energy to split the compounds, hydrogen can be released. Currently, there are three main routes available for hydrogen production depending on the feedstock (*see* Figure 1):

- reforming of natural gas, primarily through steam methane reforming (SMR);
- gasification (partial oxidation) of coal and other feedstocks such as petroleum coke, heavy fuel oil and biomass; and
- electrolysis of water.

Hydrogen is also produced as a by-product of refinery and chemical plant off-gases including chlorine and caustic soda production which accounts for approximately 20% of hydrogen production (Zapantis and Zhang, 2020; IEA, 2022a). These processes are not considered in this report.

4.2 STEAM METHANE REFORMING

Natural gas is currently the primary source accounting for over 58 MtH_2, or 62% of global hydrogen production in 2021 (IEA, 2022a). Steam methane reforming (SMR) is the leading technology for hydrogen production from natural gas at large scale. A typical hydrogen production process using SMR with carbon capture options is shown in Figure 7.

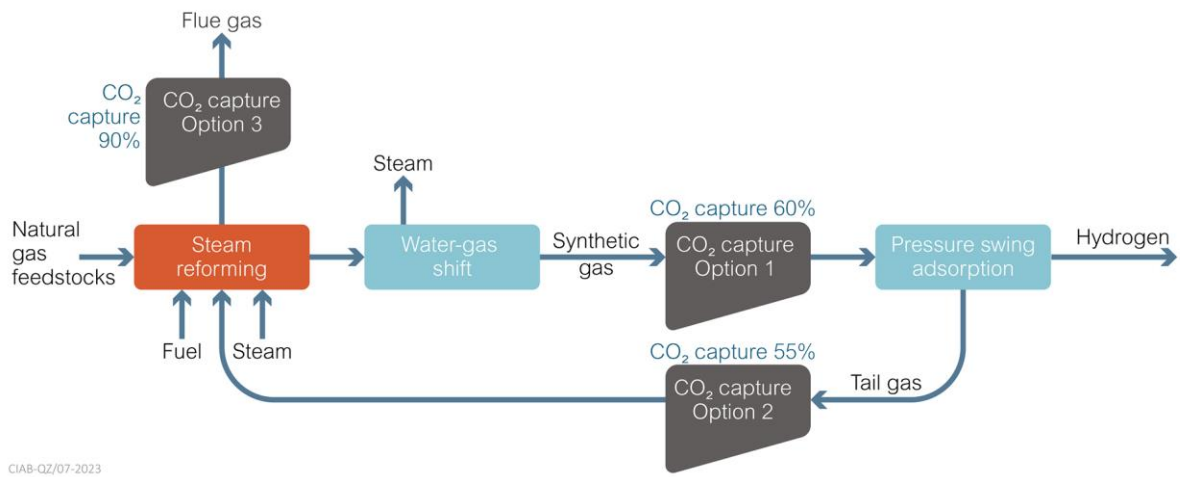


Figure 7 Process flow chart of hydrogen production using SMR with CCUS (IEA, 2019)

The basic process of converting natural gas into hydrogen in a SMR plant consists of four main steps: feedstock purification, steam reforming, shift reaction/syngas heat recovery, and raw hydrogen purification. Natural gas, after the removal of impurities which are detrimental to the catalysts downstream, is introduced with steam into the primary steam reformer. Here, it is converted to hydrogen and carbon monoxide (CO). The gas stream exiting the primary reformer is then sent through a water-gas shift (WGS) reactor to produce additional hydrogen and convert CO to CO_2. The hydrogen is separated from the syngas and purified subsequently to a purity of up to 99.999% (IEAGHG, 2017). The steam supplied to the reformer is generated by a furnace burning natural gas. The tail gas from the pressure swing adsorption (PSA) unit contains residual hydrogen and methane and is used as fuel to heat the steam reformer. Additional fuel (natural gas) is used to provide the heat required by the SMR reaction as the overall SMR process is strongly endothermic as shown below:

SMR:	$CH_4 + H_2O \leftrightarrow CO + 3H_2 \ (\Delta H^o_{298} = 206\ kJ/mol)$	Eq 1
WGS:	$CO + H_2O \leftrightarrow CO_2 + H_2 \ (\Delta H^o_{298} = -41\ kJ/mol)$	Eq 2
Overall reaction:	$CH_4 + 2H_2O \leftrightarrow CO_2 + 4H_2 \ (\Delta H^o_{298} = 165\ kJ/mol)$	Eq 3

The energy consumption of SMR is even higher if the evaporation of water (ΔH^o_{vap} = 44 kJ/mol_{H2O}) is included. Thus, SMR-based hydrogen production process is energy demanding. In modern SMR plants, the energy efficiency of the process is optimised by waste heat recovery to produce steam. Overall, a SMR-based hydrogen plant produces steam in excess of the requirement of the steam reforming reactions. The excess steam produced is usually exported (IEAGHG, 2017).

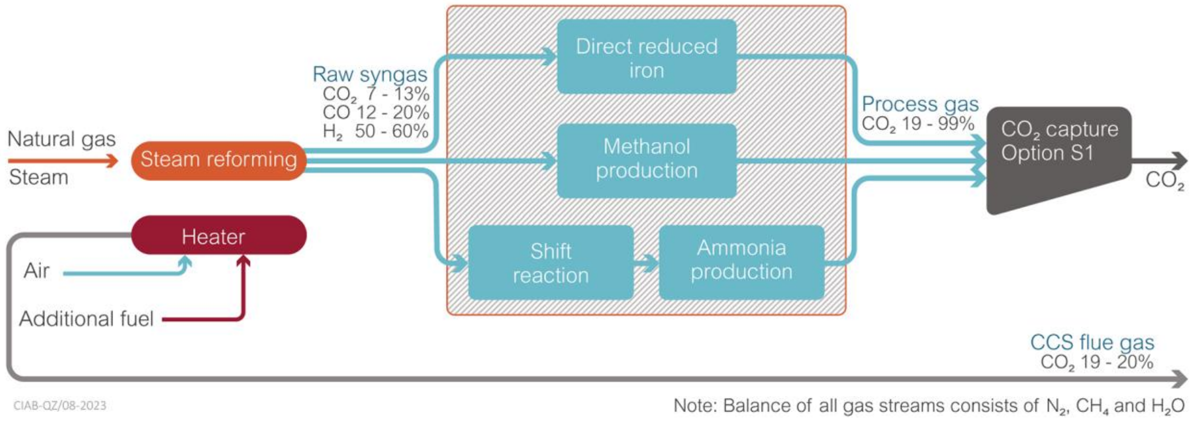


Figure 8 Typical SMR plants for supplying hydrogen to local industrial processes with CCUS options (modified from Zapantis and Zhang, 2020)

For SMR plants that produce hydrogen for local industrial applications such as DRI and chemicals, where high purity hydrogen is not required, the PSA and even the WGS step can be avoided as shown in Figure 8. In this study, all analyses are based on the pure hydrogen production process shown in Figure 7.

In SMR plants, natural gas is both a fuel and a feedstock. Typically, 30-40% of it is combusted to fuel the process, generating 'utility' CO_2 – a stream of furnace flue gas with diluted CO_2 (IEA, 2019). The rest of the natural gas is used as feedstock (with water) for hydrogen production during which more concentrated 'process' CO_2 is produced. Combining CCUS with SMR plants can reduce CO_2 emissions significantly if applied to both 'process' and 'utility' emission streams. There are several options to capture CO_2 at an SMR plant with various overall capture rates and plant efficiencies. For process CO_2, it can be separated and captured from the high-pressure shifted syngas stream (Option 1 in Figure 6) reducing emissions by up to 60%, or from the PSA tail gas (Option 2) cutting emissions by 55%. CO_2 can also be captured from the more dilute furnace flue gas (Option 3), increasing the overall reduction in emissions to 90% or more.

4.3 COAL GASIFICATION

Coal gasification for hydrogen or general chemical production via syngas is the second main source, at 18 MtH_2, or 19% of global hydrogen production in 2021 (IEA 2022a). It is a well-established technology that has been used for decades by the chemical and fertiliser industries and more recently by power producers. Most (80%) of the coal gasification plants in operation today are in China, with the rest located in countries such as Japan and the USA.

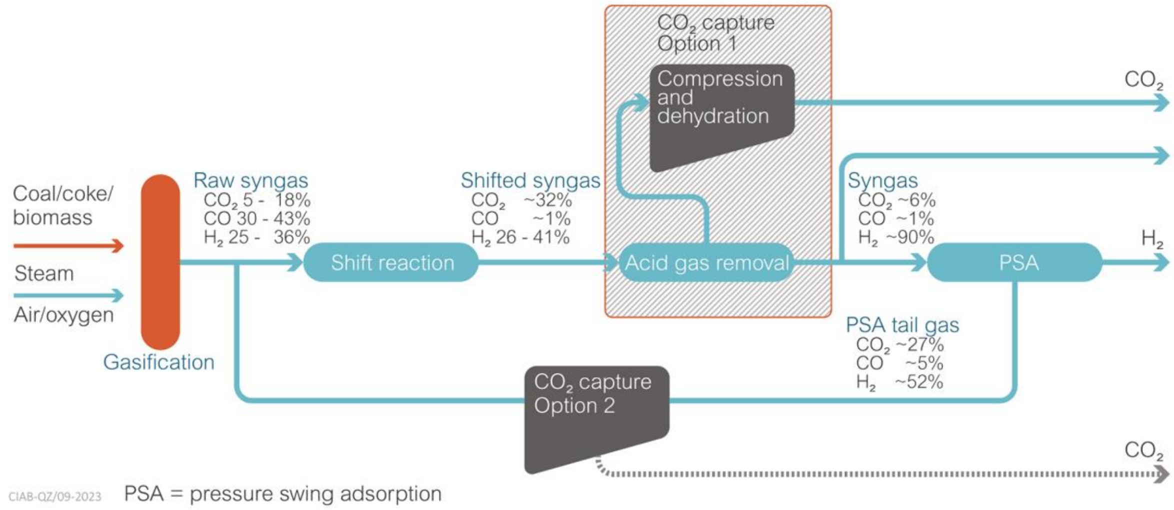


Figure 9 Hydrogen production process using coal gasification with CCUS (Zapantis and Zhang, 2020)

Figure 9 shows a process flow chart of hydrogen production using coal gasification with CCUS. In a coal gasification-based hydrogen plant, coal is prepared and then enters a gasifier in which it is partially oxidised in the presence of H_2O to generate a syngas of mainly CO and hydrogen. After the removal of particulates, sulphur and other impurities, the syngas is upgraded by converting the CO to CO_2 and more hydrogen using the WGS reaction. The hydrogen is then separated from the syngas and treated in a PSA unit to achieve high purity (>99.5%) (IEAGHG, 2017).

Coal has a low H/C ratio of an average of 0.1:1 compared to 4:1 for methane. Thus, hydrogen production using coal produces twice as much CO_2 emissions as natural gas (IEA, 2019). The high CO_2 emissions intensity of coal-based hydrogen means that carbon capture technology will be required for hydrogen from coal to have a future in a low-emission energy system. As CO_2 removal from syngas after WGS via an acid gas removal system is an integral part of the coal gasification process, this CO_2 can be captured (Option 1 in Figure 9) by adding CO_2 compression and dehydration devices (Zapantis and Zhang, 2020). A large proportion of CO_2 is separated via acid gas removal; the remaining CO_2 can be captured from the PSA tail gas using a capture device (Option 2).

Descriptions of low-emission hydrogen production using combined coal gasification and CCUS technologies can be found in a recent ICSC study by Kelsall (2021). The carbon intensity of hydrogen from coal, gas and water electrolysis using different technologies are discussed and compared in Section 4.7.

4.4 WATER ELECTROLYSIS

Water electrolysis is a developing industry accounting for 0.035 MtH_2 or 0.04% of global production in 2021 (IEA, 2022a). It is an electrochemical process driven by electric power that splits water into hydrogen and oxygen based on the following overall chemical reaction:

$$2H_2O \rightarrow 2H_2 + O_2 \ (\Delta H^o_{298} = 286\ kJ/mol) \qquad \text{Eq 4}$$

Currently there are three main electrolyser technologies: alkaline, proton exchange membrane (PEM), and solid oxide electrolysis cell (SOEC). Alkaline electrolysis is a commercial technology that has been used for over a century, particularly for hydrogen production in the fertiliser and chlorine industries. Several alkaline electrolysers run on hydropower with a capacity of up to 165 MWe were built in countries such as Egypt and Norway, although almost all of them were decommissioned when natural gas SMR for hydrogen production expanded in the 1970s (IEA, 2019). Today, the world's largest alkaline electrolyser plant in operation is Baofeng Energy's 150 MW hydrogen plant which was commissioned in December 2021 in China, whilst a 260 MW alkaline electrolyser facility with an output of 0.02 Mt/y of renewable hydrogen began construction in 2022 by Chinese oil giant Sinopec (Collins, 2022a). The Baofeng Energy's electrolyser is 30 MW, making it the world's largest. Alkaline electrolysers can operate from 10% load to full design capacity and have relatively low capital costs compared to the other electrolyser technologies as they do not require the use of precious materials. Developments in alkaline technology continue with a focus on performance improvement, cost reduction and upscaling. Although the established alkaline technology operates mainly at atmospheric pressure, pressurised systems have entered the market. Pressurised alkaline systems reduce the energy required for hydrogen compression and are also better equipped to respond to changes in power input when combined with variable renewable energy (VRE) (DNV, 2022).

PEM electrolysis is also a mature, commercial technology first introduced in the 1960s to overcome some of the operational drawbacks of alkaline electrolysers. It uses pure water as an electrolyte solution, and so avoids the recovery and recycling of the corrosive potassium hydroxide electrolyte solution that is necessary with alkaline electrolysers (IEA, 2019; DNV, 2022). PEM electrolysers operate at higher pressure, so they have a smaller footprint than alkaline electrolysers, and can produce highly compressed hydrogen (up to 10–20 MPa in some systems compared to 0.1–3 MPa for alkaline electrolysers). PEM electrolysers offer flexible operation. They can ramp up and down rapidly, making it a suitable technology to follow changes in power input from VRE and to provide frequency reserve and other grid services. Also, PEM has a wide operation range from zero load to 160% of design capacity (meaning it is possible to overload the electrolyser for some time). However, PEM electrolysers need expensive rare materials platinum and iridium for their electrode catalysts and membrane materials, which could limit large-scale expansion of their use. Their lifetime is currently shorter than that of alkaline electrolysers. The stack size of commercial PEM electrolysers is small, and the largest PEM electrolyser in operation today has a capacity of 20 MW. Therefore, their overall costs are higher than those of alkaline electrolysers, and they are less widely deployed.

SOECs are an emerging technology that is commercially available but is still far behind alkaline and PEM electrolysers in terms of scale and maturity (DNV, 2022; IEA, 2019). SOECs operate at high temperatures of 600–1000°C, use steam instead of liquid water and can achieve a high degree of electrical efficiency. A unique advantage of SOECs is their capability to directly form syngas using co-electrolysis of steam and CO_2 for subsequent conversion to a synthetic fuel and to produce a mixture of hydrogen and nitrogen with co-electrolysis of steam and air. The latter is advantageous when combined with ammonia production, saving costs on air separation units to produce nitrogen. The overall efficiency of SOECs can be further improved when waste heat from synthetic fuel or the ammonia production process is recovered for steam production. Unlike alkaline and PEM electrolysers, it is possible to operate a SOEC electrolyser in reverse mode as a fuel cell, converting hydrogen back into electricity. This means it could provide balancing services to the grid in combination with hydrogen storage facilities. This would increase the overall utilisation rate of the equipment. The current focus for development is on commercialisation, upscaling, lifetime improvement and cost reduction of SOECs. The latter two still need much progress before being competitive with alkaline and PEM electrolysers. One key challenge is to address the degradation of materials that results from the high operating temperatures.

Anion exchange membrane (AEM) is another electrolysis technology that is progressing in development, but it is not yet commercially available at scale. It shares many similarities with PEM in terms of design but uses cheaper materials. The key challenge is to extend its operational life. Development is also focused on cost reduction and further improvements (DNV, 2022).

The characteristics of the main electrolysers are compared in Table 4. It is probable that all the technologies will be used in future, although for different applications (DNV, 2022). Atmospheric alkaline electrolysers might be the preferred option for large scale and more baseload hydrogen production as this technology is the most developed and has the lowest costs. Pressurised alkaline and PEM electrolysers are suitable for use in combination with renewable energy and will probably be used in this application, both onshore and offshore. SOECs require heat input and therefore, will likely be applied at locations where a heat source is available, for example, combining SOECs with an ammonia plant, synthesis fuel plant or nuclear plant where waste heat can be used. It should be noted that the production scale of commercial electrolyser plants is considerably smaller than SMR or coal gasification plant.

TABLE 4 CHARACTERISTICS OF DIFFERENT ELECTROLYSER TECHNOLOGIES (MODIFIED FROM IEA, 2019; DNV, 2022)

	Alkaline			PEM			SOEC		
	Today	2030	Long term	Today	2030	Long term	Today	2030	Long term
Efficiency, %	63-70	65-71	70-80	56-60	63-68	67-74	74-81	77-84	77-90
Operating pressure, MPa	0.1-3	<7†		3-8					
Operating temperature, °C	60-80			50-80			650-1000		
Stack lifetime, h	60,000-90,000	90,000-100,000	100,000-150,000	30,000-90,000	60,000-90,000	100,000-150,000	10,000-30,000	40,000-60,000	75,000-100,000
Load range, % (relative to nominal load)	10-110			0-160			20-100		
Flexibility*, s	Minutes (atmospheric alkaline) <10 (pressurised alkaline)			<1			<1‡		
Plant footprint, (m^2/kWe)	0.095			0.048		l			
Commercial status	Available			Available			Available by 2022-24		

* time to reach nominal capacity
† predictions by DNV based on manufacturer indications, literature or FCH JU targets
‡ hot system in laboratory, unknown for commercial systems – cold systems require start-up times of hours if not more

4.5 OTHER METHODS

Autothermal methane reforming (ATR) is a less commercially advanced technological alternative to SMR for producing hydrogen from natural gas (DNV, 2022; IEA, 2019). ATR combines two processes of partial oxidisation of natural gas and SMR. A simplified ATR process with CCUS is shown in Figure 10. ATR plants use pure oxygen instead of air. The primary reformer in ATR differs from the SMR in that the heat is produced in the reformer itself as combustion of some of the methane takes place in the reaction vessel. This eliminates the need for a furnace and also results in more concentrated CO_2 in the process gas which can be conveniently captured as a part of hydrogen purification. In other ways, the process is similar to SMR. For ATR, carbon capture typically takes place after the WGS reactor. An ATR reactor operates at high temperatures of around 950–1100°C and high pressures of up to 10 MPa, leading to high methane conversion and high syngas pressure at the outlet. The high-pressure syngas stream makes it possible to use mature physical absorbent technologies such as Selexol and Rectisol for CO_2 capture (Zapantis and Zhang, 2020). Studies have shown that the costs of ATR with capture rates exceeding 90% are lower than that of a comparable SMR system (H21, 2018).

Some ammonia and methanol production today already combines SMR with ATR technology, and the HyNet and H21 projects under development in the UK plan to use ATR with CCUS for low-emission hydrogen production (HyNet, 2021; IEA, 2019).

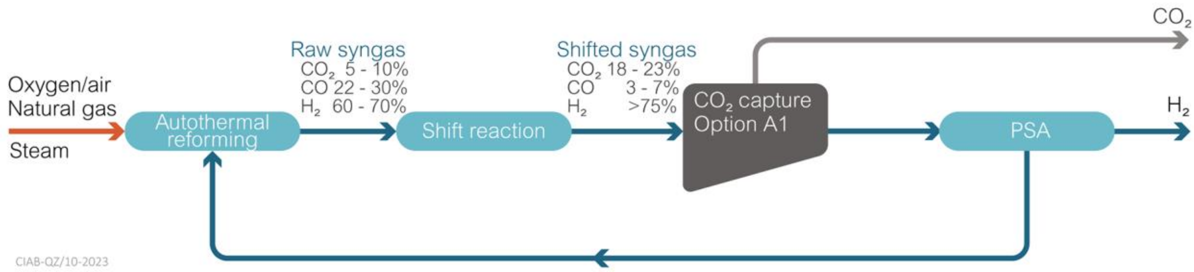


Figure 10 Process flow chart of ATR process with CCUS (Zapantis and Zhang, 2020)

Other options for using natural gas to produce hydrogen exist but are still under development at either demonstration or laboratory scale.

The following sections compare the methods of hydrogen production in terms of energy intensity, carbon intensity, water consumption, and land and materials requirements.

4.6 ENERGY INTENSITY

The energy efficiency of a hydrogen plant is influenced by several factors including the technology chosen, its size, feedstock and plant configuration. There are various steam reforming and gasification technologies, process configurations and designs for hydrogen production from natural gas and coal with varying energy efficiencies. Researchers at the US National Energy Technology Laboratory (NETL, 2022) evaluated the cost and performance of commercial state-of-the-art fossil fuel-based hydrogen production technologies. Six study cases of hydrogen production plants using natural gas SMR and ATR, coal gasification, and coal/biomass cogasification were analysed using a systematic techno-economic approach. The configurations of the six hydrogen plants analysed are summarised in Table 5. Detailed descriptions of the plant technologies and assumptions used are available from NETL (2022). The net thermal efficiency values of the hydrogen plants using different technologies from the NETL study are compared in Table 6.

TABLE 5 SUMMARY OF CASE STUDY PLANTS CONFIGURATION (NETL, 2022)

Case*	Plant type	Feedstock	Technology	Capacity, kgH_2/d	CO_2 capture, %	H_2 purification
1	Reforming	Natural gas	SMR	483,000	0	Pressure swing absorber (PSA)
2			SMR+CCUS		96.2	
3			ATR+CCUS		94.5	
4	Gasification	Illinois No 6 coal	Shell† gasifier	660,000	0	
5			Shell gasifier+CCUS		92.5	
6		Illinois No 6 coal/torrefied woody biomass	Shell gasifier+CCUS	133,000	92.6	

* all plants are assumed to be located at a generic plant site in the midwestern USA
† as of May 2018, Air Products has acquired the coal gasification technology licensing business from Shell

TABLE 6 EFFICIENCY COMPARISON OF HYDROGEN PRODUCTION METHODS (NETL, 2022)

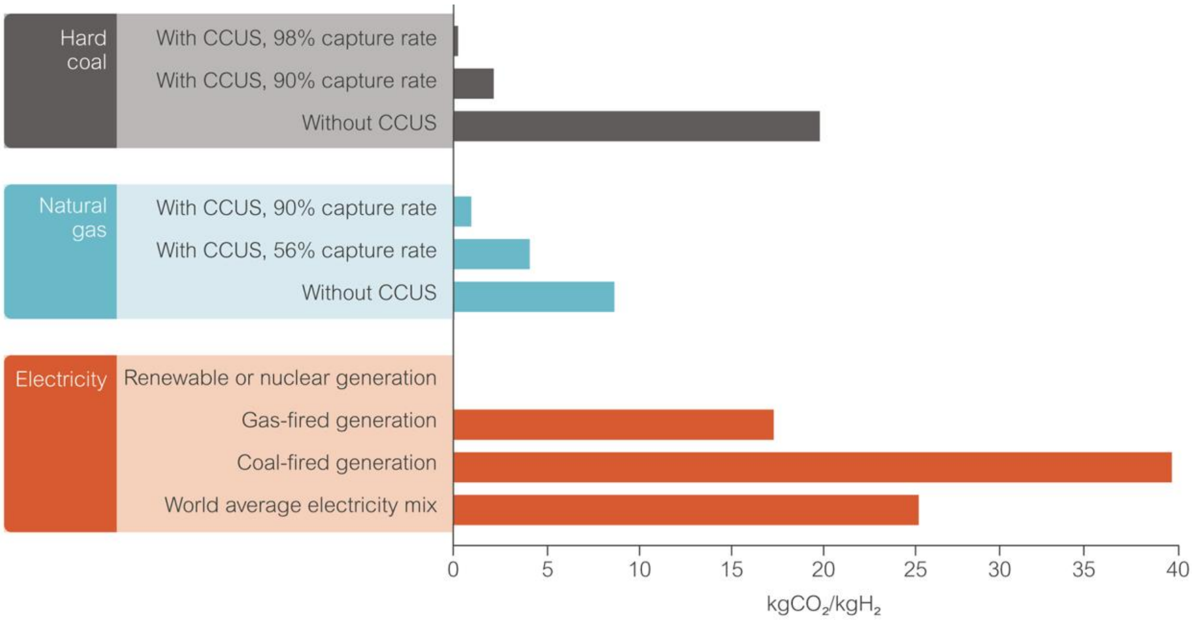
	SMR	SMR+CCUS	ATR+CCUS	Coal gasification	Coal gasification with CCUS	Coal/biomass cogasification with CCUS
Efficiency, %	75.4	68.4	67.9	65	64.1	57.9

According to NETL (2022), coal gasification-based hydrogen production has a lower energy efficiency than hydrogen production using natural gas reforming, while hydrogen from coal/biomass cogasification has the lowest efficiency. Adding CO_2 capture to the SMR plant decreases the efficiency by about seven percentage points due to additional natural gas being combusted to satisfy the thermal demands of the CO_2 removal processes (NETL, 2022). Adding carbon capture to the coal gasification plant, however, decreases the efficiency by less than one percentage point since additional feedstock is not required to support CO_2 removal, narrowing the energy consumption gap between the two methods. The energy intensity of hydrogen from coal gasification with CCUS is around 3.48 kWh/kgH_2, compared to 1.91 kWh/kgH_2 for gas SMR with CCUS (including the electricity required to produce the coal or gas) (Zapantis, 2021).

A comparison of equation 3 in Section 4.3 and equation 4 in Section 4.5 shows that the theoretical energy requirement of making hydrogen using water electrolysis is much higher than that of natural gas reforming ($\Delta H^o{}_{298}$ = 286 kJ/mol compared to $\Delta H^o{}_{298}$ = 165 kJ/mol). The average energy consumption for electrolysis is between 52.5–70.1 kWh/kgH_2 (Patonia and Poudineh, 2020). For regions where freshwater is scarce and desalination of sea water is needed to supply water to the electrolysers, an additional 3–4 kWh/kgH_2 will be consumed making electrolysis the most energy-demanding technology of the three main hydrogen production methods (IEA, 2019).

4.7 CARBON INTENSITY

Almost all fossil fuel-based hydrogen production is unabated, leading to nearly 900 Mt of direct CO_2 emissions in 2020, or 2.5% of global CO_2 emissions in energy and industry (IEA, 2021a). The CO_2 emissions from the hydrogen production pathways differ widely. Hydrogen production using unabated natural gas SMR has a CO_2 emission intensity of 8.9–9.4 $kgCO_2/kgH_2$, which can be reduced to 0.5–2 $kgCO_2/kgH_2$ by combining CCUS with the SMR process (DNV, 2022). Hydrogen production from unabated coal gasification generates around 20 $kgCO_2/kgH_2$, but the emissions can be reduced to less than 1.5 $kgCO_2/kgH_2$ by applying CCUS (Argus, 2022a). Coal gasification with a 98% rate of capture has an even lower carbon intensity, below 0.4–0.6 $kgCO_2/kgH_2$. Figure 11 compares the estimated CO_2 emission intensity of different hydrogen production pathways. It should be noted that carbon intensities shown in Figure 11 represent total CO_2 emissions from a hydrogen production process and do not include CO_2 emissions linked to the transmission and distribution of hydrogen to the end users. The capture rate of 56% for natural gas with CCUS refers to capturing only process CO_2, whereas for the 90% capture rate, CCUS is applied to both process and utility CO_2 emissions. CO_2 intensities of electricity consider only direct CO_2 emissions at the power plant. Figure 11 shows that hydrogen production from unabated coal has a much higher carbon intensity, roughly double that of unabated natural gas. The CO_2 intensity of electrolysis depends on the CO_2 intensity of the electricity input. While electrolysers powered by 100% renewable or nuclear energy emit no CO_2, electrolysers driven by grid electricity that has a large proportion of fossil-fuelled generation would result in higher carbon intensities than directly using natural gas or coal for hydrogen production. Implementing CCUS could substantially lower the CO_2 emissions of both natural gas- and coal-based hydrogen production, reducing their carbon intensity by over 90%. With a 98% capture rate, the carbon emissions from coal gasification hydrogen plant can be brought down to a level similar to, or even lower than, that of natural gas SMR plant.



1. Capture rate of 56% for natural gas with CCUS refers to capturing the feedstock-related CO_2, whereas for 90% capture rate CCUS is also applied to the fuel-related CO_2 emissions. Note that capture rates approaching 100% have been shown to be technically feasible (Feron and others, 2019)
2. CO_2 intensities of electricity taking into account only direct CO_2 emissions at the electricity generation plant: world average 2017 = 491 gCO_2/kWh; gas-fired power generation = 336 gCO_2/kWh; coal fired power generation = 760 gCO_2/kWh.
3. The CO_2 intensities for hydrogen also do not include CO_2 emissions linked to the transmission and distribution of hydrogen to the end users

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Figure 11 CO_2 emission intensity of hydrogen production (Kelsall and Baruya, 2022)

The life cycle GHG emissions of hydrogen production includes emissions from raw material extraction, processing and transport, energy supply and use, fugitive gas emissions, and Capex-related emissions. Thus, life cycle emissions represent the true carbon footprint of hydrogen from different production pathways. In the study by NETL (2022) described in Section 4.6, life cycle GHG emissions (as CO_2 equivalent $CO_{2\text{-eq}}$) of the six study cases were analysed and compared. The coal gasification-based hydrogen plant without CCUS (Case 4) had the largest carbon footprint of 20 $kgCO_{2\text{-eq}}/kgH_2$, while the coal/biomass cogasification plant with CCUS (Case 6) had the lowest carbon footprint of -1.0 $kgCO_{2\text{-eq}}/kgH_2$, (*see* Table 5). The average life cycle GHG emission of the SMR and ATR plant with CCUS (Case 2 and 3) were 4.6 and 5.7 $kgCO_{2\text{-eq}}/kgH_2$, respectively, which is approximately 10–40% higher than the 4.1 $kgCO_{2\text{-eq}}/kgH_2$ of the coal gasification plant with CO_2 capture (Case 5). NETL attributed the higher carbon footprint of hydrogen from natural gas reforming with CO_2 capture to the life cycle GHG emissions of the grid electricity and natural gas feedstock procurement, which make up about 90% of the life cycle emissions of the reforming cases with capture.

TABLE 7 AVERAGE LIFE CYCLE GHG EMISSIONS OF HYDROGEN FROM DIFFERENT PRODUCTION PATHWAYS (NETL, 2022)

	SMR	SMR+ CCUS	ATR+ CCUS	Coal gasification	Coal gasification with CCUS	Coal/biomass cogasification with CCUS
Life cycle GHG emissions, $kgCO_{2\text{-eq}}/kgH_2$	10	4.6	5.7	20	4.1	-1.0

Similar trends have been reported by the IEA (2021b) (*see* Figure 12). Hydrogen produced from electrolysis driven by Indian grid electricity that has a large share of coal power generation has a much larger carbon footprint than the direct use of natural gas or coal. Hydrogen produced from biomass has a low carbon intensity, and when combined with CCUS it has a negative carbon footprint. When considering life cycle emissions, renewable hydrogen from electrolysis powered by 100% renewable energy is not carbon-free due to emissions from the supply of materials for making electrolysers, solar panels and wind turbines. However, life cycle emissions of renewable hydrogen are lower than fossil fuel-based hydrogen production with CCUS. Life cycle GHG emissions of hydrogen from unabated coal are double that of hydrogen from unabated natural gas, while the carbon footprints of hydrogen from coal plus CCUS and natural gas with CCUS are comparable, but they are still higher than those of renewable hydrogen from wind or solar energy.

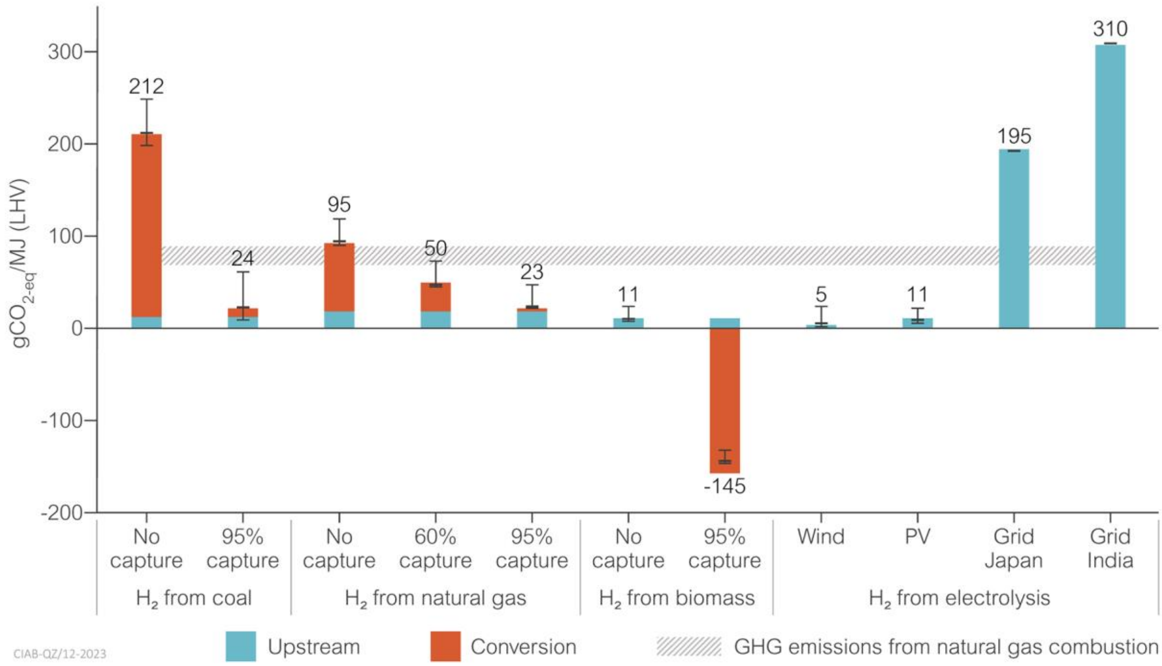

Figure 12 Indicative life cycle GHG emissions of hydrogen produced from different routes (IEA, 2021b)

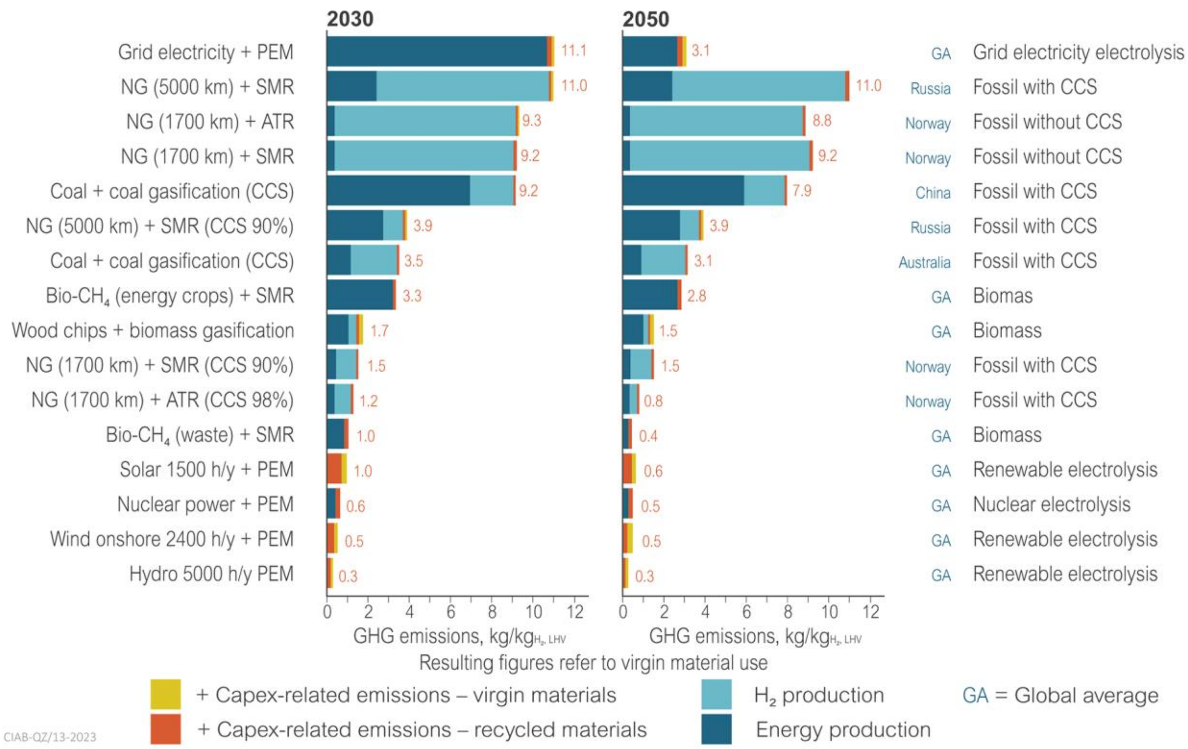

Figure 13 Life cycle GHG emissions by hydrogen production pathways in 2030 and 2050 (Hydrogen Council, 2021)

Researchers at the Hydrogen Council (2021) used a life cycle analysis (LCA) approach to evaluate the emissions intensity of hydrogen produced from various pathways. They included geographical variations, production technologies, midstream transmission and distribution vectors, and end-use applications. The results are summarised in Figure 13 and are consistent with those of NETL and the IEA. They concluded that low-emission hydrogen derived from fossil fuels can have low life cycle emissions and support the clean energy transition if the best available technologies and operational practices are used along with the highest CO_2 capture rates (98% assumed in the study).

4.8 WATER CONSUMPTION

Water is consumed in hydrogen production processes as a feedstock (process water) for the reaction and for cooling. The process water must have a low concentration of dissolved solids, which generally requires pre-treatment that consumes additional water. For electrolysis, based on the reaction stoichiometry (*see* equation 4 in Section 4.4), 9 kg of water is required for every kg of hydrogen produced. The actual water requirements will be higher due to inefficiencies and losses in the system. Electrolysis needs very pure deionised water. Considering the process of water treatment, the ratio can range between 18–24 kgH_2O/kgH_2 (Blanco, 2021). Examining the water demand for cooling systems, Lampert and others (2015) estimated that the average water consumption rate of electrolysers would be 30.4 kgH_2O/kgH_2. A recent study into water demands for hydrogen production found that cooling of electrolysers using an evaporative cooling system can require an additional 30–40 kgH_2O/kgH_2 (Coertzen and others, 2021). The cooling load increases significantly over time as the efficiency of the electrolyser stack decreases with increasing operating time. The cooling demand for an electrolyser stack can typically increase by 40–70% over the life of the stack. In addition, the water demand will be higher if other cooling requirements are taken into account such as the multi-stage compressors with intercooling to compress the hydrogen produced to a suitable pressure for storage or use. Therefore, the total water demand of electrolysis could be as high as 60–90 kgH_2O/kgH_2. Water demands for hydrogen production from different pathways are compared in Table 8.

For hydrogen production using SMR, the stoichiometric water consumption is 4.5 kgH_2O/kgH_2. However, this water needs to be demineralised to achieve boiler feed water quality, so rejects from this process need to be taken into account. In addition, steam losses and losses from evaporative cooling add to the water consumption, and the CO_2 capture process will further increase water demand of the SMR process by 10–20% (Lampert and others, 2015). For ATR, the overall water demand will be similar, and possibly slightly higher than for SMR (Coertzen and others, 2021).

Water consumption for hydrogen production from coal gasification is high and comparable to that of electrolysis, which does not increase by adding carbon capture (Lampert and others, 2015).

TABLE 8 WATER DEMAND FOR HYDROGEN PRODUCTION (COERTZEN AND OTHERS, 2021; LAMPERT AND OTHERS, 2015)

<table>
<tr><th rowspan="2">Production pathway</th><th rowspan="2">Stoichiometric demand, kgH_2O/kgH_2</th><th colspan="2">Total demand, kgH_2O/kgH_2 (assuming good quality raw water import and evaporative cooling)</th></tr>
<tr><th>Coertzen and others, 2021</th><th>Lampert and others, 2015</th></tr>
<tr><td>SMR</td><td>4.5</td><td>15*–40</td><td>11.8</td></tr>
<tr><td>SMR with CCUS</td><td>4.5</td><td>18*–44</td><td>13.7</td></tr>
<tr><td>Coal gasification</td><td>Dependent on C:H ratio in coal and coal moisture content</td><td>70</td><td>31.3–31.8</td></tr>
<tr><td>Biomass gasification</td><td>Dependent on C:H ratio in biomass and biomass moisture content</td><td>60</td><td>16.5</td></tr>
<tr><td>Water electrolysis</td><td>9</td><td>60–90</td><td>30.4</td></tr>
<tr><td colspan="4">* includes some air cooling</td></tr>
</table>

The total water consumption for hydrogen production is affected by several factors such as cooling technology, raw water quality, and the recovery and use of wastewater. Air cooling can reduce water demand significantly. Poor quality raw water with high salinity and other contaminants results in greater consumption of water. As an example, for electrolytic hydrogen production with demineralised water, manufacturers typically quote 10.5 kgH_2O/kgH_2 for water feed to electrolysers, but this rises to 18 to 22 kgH_2O/kgH_2 if tap water is used (Walker and others, 2018). For brine or grey water feedstock, the water requirement would increase significantly along with increasing costs of water purification.

It should be noted that in addition to hydrogen production, hydrogen is typically converted to a carrier of choice such as ammonia, liquefied hydrogen or liquid organic hydrogen carrier (LOHC) for long-distance transport. Each of these carriers requires a conversion step with associated steam, boiler feed water and/or cooling water demand.

4.9 LAND REQUIREMENT

Due to the vastly different energy densities of fossil fuels and renewables, there are substantial variations in the average power or capacity density between fossil-fuelled generation and renewables as illustrated in Figure 14. As a result, renewables such as solar and wind require a much larger land area to generate a unit of electricity. Studies found that even when the land use impacts of mining or extracting fuels are included, land use intensities of renewable generation are greater than those of fossil fuel and nuclear generation (Saunders, 2020). According to a US solar system design and installation company YSG Solar (2021), a solar facility requires 20,000 m^2 (5 acres) of land per 1 MW capacity. Wind power has a higher land use intensity of generation than solar power due to its lower capacity density. The land use intensity of generation based on MWh requirement is even higher because solar and wind power plants have a low-capacity factor.

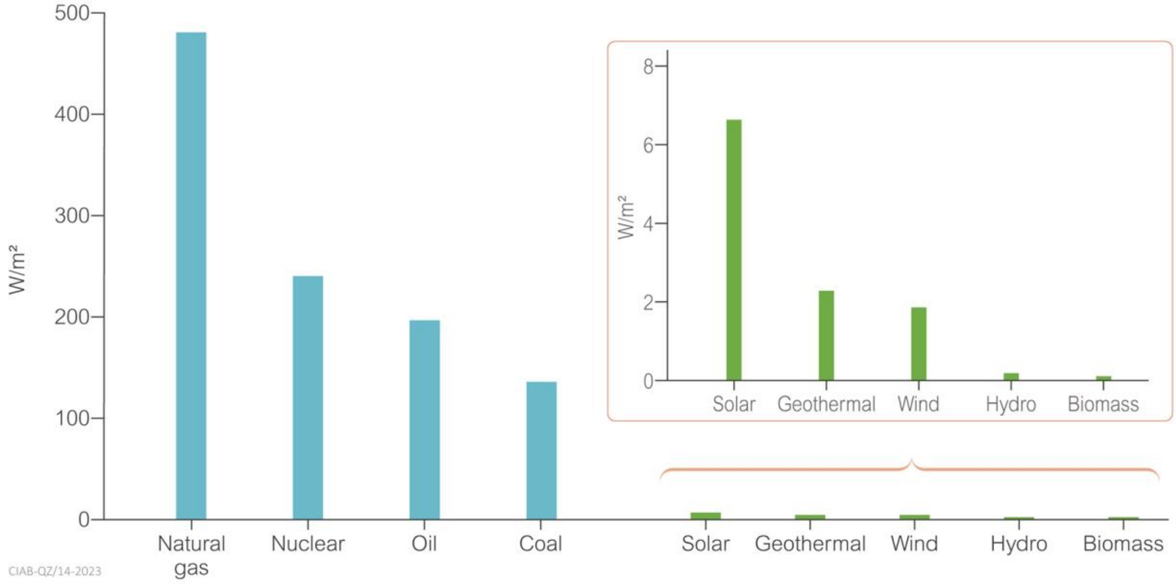

Figure 14 Median capacity densities of fossil fuel and nuclear generation and renewable generation (Saunders, 2020)

TABLE 9 FOOTPRINT OF HYDROGEN PLANTS (WALKER AND OTHERS, 2018)

	Electrolyser (including the balance of plant)		Natural gas reformer with CCUS		Coal gasification with CCUS	Biomass gasification
	Alkaline	PEM	SMR	ATR		
Plant footprint, m^2/MWh H_2 (HHV)	136	73.7	107–160	55	2520	800

Renewable hydrogen requires a sufficient land area to host the wind and/or solar generation capacity whilst fossil fuel-based low-emission hydrogen requires suitable geological sites for the storage of CO_2. A dataset has been created for the UK Department for Business, Energy & Industrial Strategy (BEIS) to support analytical and modelling work around hydrogen's potential role in heat decarbonisation (Walker and others, 2018). The dataset covers the cost and performance of the individual components of all aspects of a potential hydrogen value chain from production through to end use. The footprints of the hydrogen plants from the dataset are listed in Table 9. An electrolysis hydrogen plant has a footprint comparable to that of a natural gas reforming hydrogen plant with CCUS and is substantially smaller than the footprint of a coal gasification-based hydrogen plant with CCUS. However, when including the land requirement of a renewable power plant needed to drive the electrolysers to produce renewable hydrogen, the picture changes dramatically. Figure 15 shows the results by Zapantis (2021) who compared the land area required for the production of 1.76 MtH_2/y from coal or gas with CCS and electrolysis powered by renewable electricity. The land requirement for coal gasification and gas SMR with CCUS assumes a 500 km CO_2 pipeline in a 20 m wide corridor, 2 km^2 for the plant and ten injection wells over 5 km^2 for coal with CCUS, and four injection wells over 2 km^2 for SMR with CCUS. CO_2 captured requiring geological storage is 21.5 kg/kgH_2 for coal with CCUS and 7.2 kg/kgH_2 for SMR plus CCUS. Thus, substantial changes in land and sea use would occur if large volumes of renewable hydrogen were produced from the electrolysis of water powered by solar and/or wind energy.

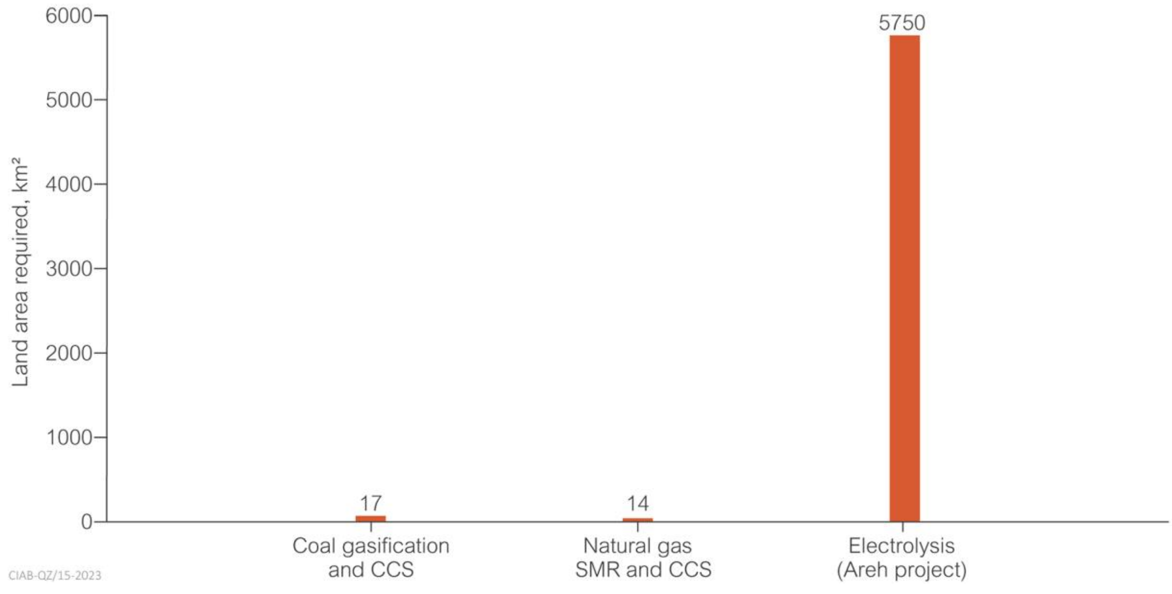

Figure 15 Comparison of land requirement of a hydrogen plant with a capacity of 1.76 MtH_2/y using different technologies (Zapantis, 2021)

4.10 MATERIAL REQUIREMENTS

The design of catalysts or electrocatalysts depends on the operating conditions of the water electrolysis cell. PEM electrolysers operate under highly acidic environments and require significant quantities of expensive catalysts such as platinum and iridium as well as titanium components.

Platinum and iridium are two of the scarcest, most energy and emission-intensive metals used in electrolysers (IRENA, 2020). Platinum production has an energy intensity of 67.5 MWh/kgPt and emits about 12.5 $tCO_{2\text{-eq}}$/kgPt which translates into about 0.01 $kgCO_{2\text{-eq}}/kgH_2$. Depending on the catalysts used, SOECs will use more types of critical materials and/or rare earth elements such as cobalt, lanthanum, strontium, gadolinium, yttrium, zirconium or cerium (Nechache and Hody, 2021). Alkaline processes have a different electrochemical environment that enables the use of non-precious catalysts such as nickel and iron, which significantly reduces their capital cost compared to PEM. Alkaline electrolysers generally use nickel to resist the highly caustic environment. Although some designs may use platinum and cobalt, commercial alkaline electrolysers that do not use these materials are available today for renewable hydrogen production (IRENA, 2020). Figure 16 lists some of the critical materials used for electrolysers and their energy intensity and life cycle GHG emissions.

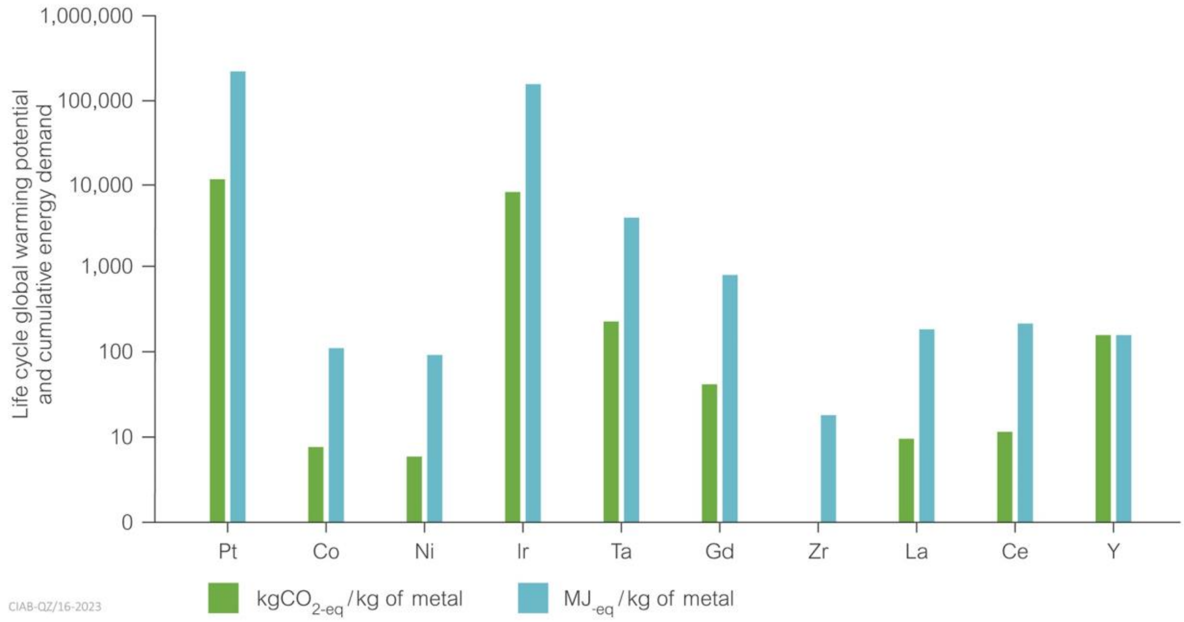

Figure 16 Energy intensity and life cycle GHG emissions of critical materials used for electrolysers (IRENA, 2020)

In addition to the critical materials and rare earth elements used for electrolysers, the construction of solar and wind power plants that drive the production of renewable hydrogen requires large amounts of materials. Table 10 shows materials required for coal and natural gas combined cycle power generators, and for solar PV and wind turbine generators (including materials for upstream energy collection). Solar and wind power plants use large quantities of cement, concrete, glass and steel, the production of which is energy- and emissions-intensive. In 2020, the production of steel generated over 3 $GtCO_2$, corresponding to 8% of global CO_2 emissions, while cement production accounted for around 7% of global CO_2 emissions (Peplow, 2021; GCCA, 2021). This will affect the life cycle carbon footprint of renewable hydrogen.

TABLE 10 MATERIAL REQUIREMENTS OF FOSSIL-FUELLED AND RENEWABLE POWER GENERATION (SAUNDERS, 2020)

Materials, t/TWh	Natural gas*	Coal*	Wind†	Solar PV†
Aluminum	1	3	35	680
Cement	0	0	0	3700
Concrete	400	870	8000	350
Copper	0	1	23	850
Glass	0	0	92	2700
Iron	1	1	120	0
Plastic	0	0	190	210
Silicon	0	0	0	57
Steel	170	310	1800	7900

* generator only
† generator and upstream energy collection materials

5 HYDROGEN DISTRIBUTION AND THE GLOBAL SUPPLY CHAIN

5.1 KEY MESSAGES

Hydrogen has long been used in industry. It is currently delivered commercially by road (in cryogenic liquid tankers or compressed into long cylinders that are stacked on a trailer to be hauled by trucks) or by pipeline (where the quantities and stability of demand justify this method).

Like natural gas, hydrogen can be transported by ship or barge either as liquefied or compressed; demonstrations are underway. Hydrogen can also be converted to ammonia for such transport because it is more energy dense by volume than compressed or liquefied hydrogen and is easier to store. Upon reaching its destination, the ammonia can be cracked to release the hydrogen for end use or used directly as a fuel.

A viable hydrogen industry requires that it can be delivered to end users competitively but this involves a trade-off. As production volumes are currently relatively small, most hydrogen is produced in distributed production facilities on-site or adjacent to users. Accordingly, delivery costs are relatively low but the cost of production is likely to be higher than from a large, centrally located facility. On the other hand, such a large facility is likely to be distant from the points of end-use thus raising the cost of delivery.

The projected growth in hydrogen demand to reach NZE will require expansion of existing transport infrastructure and investment in new infrastructure. It will also require new technologies, such as ships and barges to carry hydrogen at high-density.

Key challenges to hydrogen delivery include reducing costs, improving energy efficiency and building hydrogen delivery infrastructure while maintaining hydrogen purity and minimising hydrogen leakage.

Today, hydrogen is transported from the point of production to the point of use by road and pipeline. The delivery technology includes tankers, liquefaction plants, storage facilities, compressors and dispensers. Growth in hydrogen demand will require considerable expansion of such infrastructure and research to allow extension to bulk shipping and barging of hydrogen. The transport and storage of hydrogen is challenging due to its low energy density, embrittlement, and safety concerns. These unique properties present special cost and safety obstacles at every distribution step from manufacturing to end-use. As a result, hydrogen is essentially a local business today as about 85% of it is produced and consumed on-site within a facility rather than being traded widely (IEA, 2019). Where hydrogen is sold, it is usually not transported far because of the logistical difficulties and costs. A viable hydrogen industry requires that hydrogen can be delivered to end users competitively. Activities are ongoing to develop technologies for long-distance transport of hydrogen at high-density such as ships and barges and to reduce the costs, and progress has been made.

In this chapter, hydrogen supply issues including hydrogen storage, transport and distribution, infrastructure, and safety issues are discussed.

5.2 DISTRIBUTION OF HYDROGEN

5.2.1 Storage

The development of a widespread hydrogen economy and large-scale applications of hydrogen in power, transport and industry will require the establishment of intercontinental hydrogen value chains, including a mix of hydrogen storage technologies which will vary in size and duration. For example, hours of hydrogen storage are needed at vehicle refuelling stations, while days to weeks of storage may be required at end-user sites to guarantee the ability to match hydrogen supply and demand. Larger storage capacity would be required for longer periods if hydrogen is used to bridge major seasonal changes in electricity and/or heat supply or to provide system resilience.

Hydrogen can be stored physically in tanks either in a gaseous form which typically requires high pressures of 35–70 MPa or in a liquid form at a cryogenic temperature of −252.8°C. Geological storage options such as salt caverns, depleted natural gas or oil reservoirs and aquifers are all possible for the large-scale and long-term storage of hydrogen. They are currently used for natural gas storage and provide significant economies of scale, high efficiency (ratio of the quantity of hydrogen injected to the quantity extracted), low operational costs and low land costs (IEA, 2019). In general, geological storage is the best option for large-scale, long-term storage, while tanks are more suitable for short-term, small-scale storage.

At present, hydrogen is usually stored and delivered in compressed gas or liquid form. Geological storage is proven as a technology, but there is limited practical experience of large-scale hydrogen storage and its availability is determined by geography. Currently, hydrogen storage in salt caverns is restricted to only four operational sites in the USA and the UK (Hamilton and others, 2022). For large-scale and long-term storage, hydrogen can also be converted to a hydrogen carrier such as ammonia and methanol. This option is discussed in more detail in Section 5.2.2. Alternatively, hydrogen can be stored using solid or liquid materials that can absorb, adsorb or react with hydrogen to bind it. Materials-based storage is at an early stage of development with ongoing R&D to create materials such as metal and chemical hydrides that could potentially enable greater densities of hydrogen to be stored at atmospheric pressure and/or allow a lightweight, inexpensive pressure container to be used for hydrogen storage.

5.2.2 Transmission and distribution

Hydrogen can be moved by ship, barge, truck, rail, or pipeline, in gaseous or liquid form, or via a hydrogen carrier. Hydrogen carriers are molecules with a significant hydrogen content which are liquid at conditions close to ambient temperatures and pressures, making them easier to transport or store above ground without needing specialist containment. Hydrogen carriers include ammonia (NH_3) and methanol (CH_3OH). The potential of liquid organic hydrogen carriers (LOHC) such as toluene and di-benzyl toluene are being explored. Ammonia is a well-established hydrogen carrier with a volumetric energy density nearly double that of liquefied hydrogen, making it easier and cheaper to store and transport (Zhu, 2022). Ammonia can also be combusted directly as a fuel in some applications without needing cracking to release hydrogen, reducing the related energy loss and costs. However, there is an energy penalty in the conversion of hydrogen into a hydrogen carrier and in the subsequent regeneration of hydrogen at the point of use. This means less hydrogen is available to the end-user if the hydrogen were to be used to provide the energy required by the reconversion processes. There will be added costs as discussed in Section 5.2.3. If the energy used in the conversion processes is not renewable, then there will also be a carbon penalty.

Transporting hydrogen by truck in gaseous or liquid form or via a carrier such as ammonia or LOHC is a mature option. However, transport of compressed hydrogen gas by truck is economically viable only for small quantities and for short distances such as to supply refuelling stations. Transporting liquefied hydrogen by truck is more common for longer distances of up to 4000 km (*see* Figure 17).

Transporting hydrogen through pipelines is also a mature technology. It is an inexpensive and robust method for certain distances depending on several factors including the volume of hydrogen transported. There are over 2500 km of hydrogen pipelines in place in the USA, while within Europe, the longest pipelines are in Belgium (600 km) and Germany (400 km) (DNV, 2022). Some of the disused gas grids could also be used for hydrogen transmission.

Hydrogen can also be transported as a blend in natural gas, which may be a partial solution during a transition from natural gas to hydrogen. Blending hydrogen into the existing natural gas infrastructure could support the initial deployment of low-emission hydrogen by avoiding the significant capital costs of developing new hydrogen transmission and distribution infrastructure and providing learnings for a pure hydrogen grid. Various pilot projects have been launched in recent years to examine hydrogen blending in the gas grid.

Hydrogen can also be moved via a liquid hydrogen carrier in a pipeline. Transporting ammonia via pipelines is cheaper than moving hydrogen gas, especially for longer distances. There are also dedicated pipelines for transporting ammonia which are proven to be safe and low cost (Zhu, 2022). However, the cost of converting hydrogen to ammonia and the possible need to reconvert ammonia back to hydrogen needs to be considered.

Hydrogen transport by ship is technically possible for larger distances where pipelines are not an option. Its low volumetric energy density means that hydrogen is best liquified or converted into a more energy-dense liquid such as ammonia or LOHC before being loaded onto a ship. Ammonia is the most promising hydrogen carrier as it is already an internationally traded commodity; over 120 ports have ammonia storage facilities (IRENA, 2022c). For shipping liquid hydrogen, the hydrogen must be cooled to -253°C at port terminals before being loaded onto highly insulated tanker ships. While liquefaction is a proven and commercialised technology, liquid hydrogen shipping and large-scale storage require management of the boil-off losses, which remains a significant challenge. In addition, the liquefaction process is energy intensive and would consume 25–35% of the initial quantity of hydrogen if the hydrogen itself were to be used to provide this energy (IEA, 2019). IRENA (2022c) suggests that if hydrogen is converted to and from ammonia as a carrying agent, then the shipping cost is small relative to the conversion for long-distance transport. Trials for the transport of hydrogen by barge or ship is a new development for this nascent industry. In a world first, the Suiso Frontier, built in late 2019 by Japan's Kawasaki Heavy Industries, transported liquid hydrogen with a capacity of 1250 m^3 from Australia to Japan in February 2022 (Pekic, 2022).

5.2.3 Transmission costs

Today, hydrogen trade is local. It will need to become an internationally traded commodity to achieve NZE and to meet the expected demand for hydrogen. The low energy density of hydrogen means that it is expensive to transport over long distances. The cost-effectiveness of hydrogen transport is determined mainly by distance and volume as illustrated in Figure 17. For example, if transporting a small volume of 0.3 MtH_2/y, pipelines could be cheaper than ships for distances below 1500 km, while for large volumes of 1.5 MtH_2/y, newly built hydrogen pipelines would be the most cost-effective option for distances up to 4000 km (IRENA, 2022a). Where repurposed natural gas pipelines are an option, the cost-effective range could extend to 8000 km. Analysis for the European Hydrogen Backbone (EHB) found that hydrogen pipelines based on repurposed gas infrastructure are the most cost-efficient option for long-distance, high-volume transport of hydrogen within the EU and UK (Wang and others, 2021). The levelised cost of transporting hydrogen via EHB is estimated to be 0.11–0.21 €/kgH_2/1000 km on average, which outcompetes transport by ship for all reasonable distances within Europe and between Europe and potential neighbouring export regions. If hydrogen is transported exclusively via subsea pipelines, the cost would be 0.17–0.32 €/kgH_2/1000 km.

Figure 18 shows the estimated costs of hydrogen transport via different modes including storage costs but excluding costs of distribution and reconversion. As the transmission distance increases, the cost of transporting hydrogen by pipeline escalates faster than the cost for ammonia as a greater number of compressor stations are required. While it is cheaper to move ammonia by pipeline than hydrogen, conversion costs raise the total cost of transmitting ammonia. In addition, converting ammonia or LOHC back to hydrogen adds about 1 $/$kgH_2$ and 0.4 $/$kgH_2$, respectively (DNV, 2022). For a transmission distance of 2500 km, the cost of transporting ammonia by pipeline, including the conversion cost, becomes broadly similar to the cost of transporting hydrogen as a gas at around 2 $/$kgH_2$ (IEA, 2019).

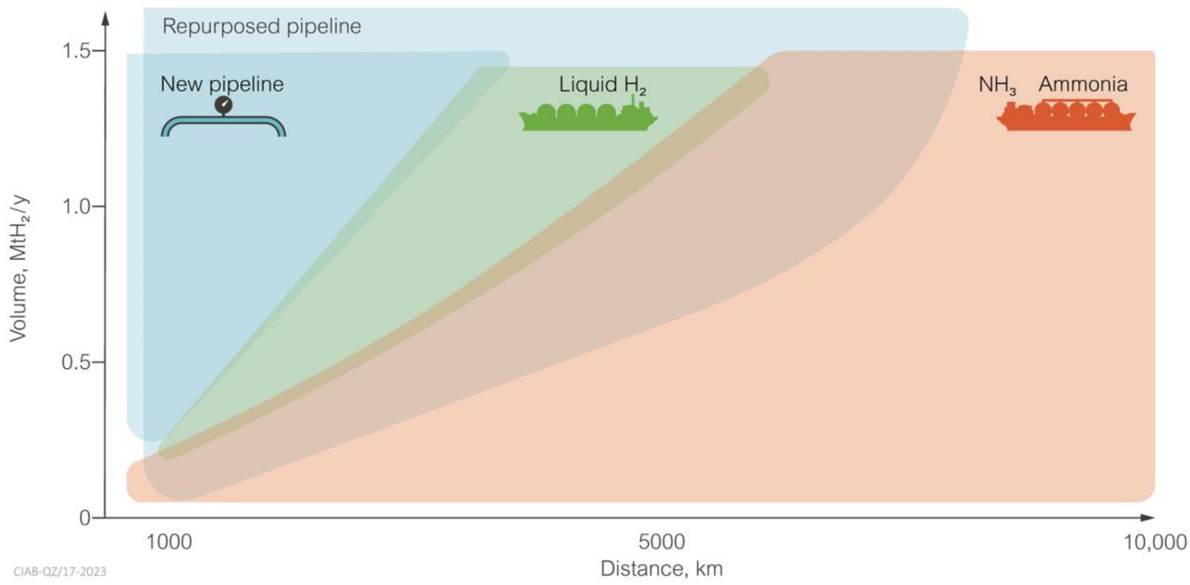

Figure 17 **Cost efficiency of transport options when considering volume and distance (IRENA, 2022a)**

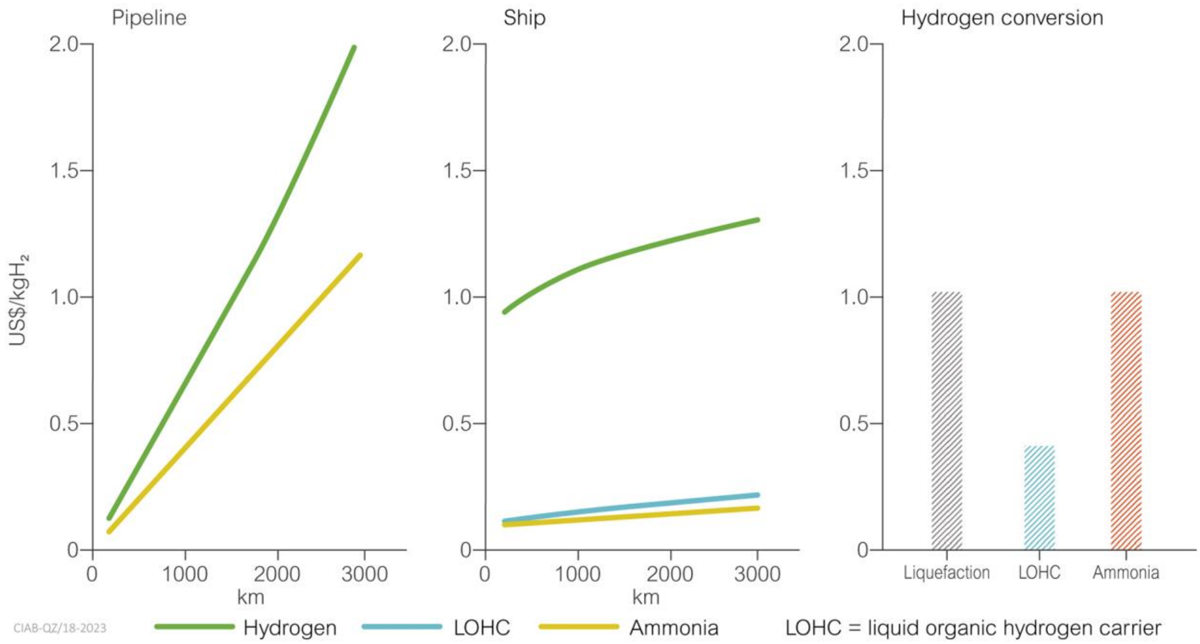

Figure 18 **Cost of hydrogen storage and transmission by pipeline and ship, and cost of hydrogen conversion (IEA, 2019)**

For transport by ship, hydrogen gas must be liquefied or converted prior to transport, which incurs costs. Storing liquid hydrogen at import and export terminals is also expensive. The cost of conversion and transporting hydrogen 1500 km by ship as a LOHC is 0.6 $/kgH_2$, as ammonia is 1.2 $/kgH_2$ and as liquid hydrogen is 2 $/kgH_2$ (IEA, 2019). The shipping cost rises with increasing distance but is small relative to the conversion cost. Thus, long distances have little impact on total costs, making shipping more attractive for long distances.

Blending hydrogen into the natural gas network will also incur an additional cost due to the need for injection stations as well as a higher operating cost.

It should be noted that the estimated costs quoted above relate solely to hydrogen transmission, and a full cost comparison of the different modes needs to consider the costs of local distribution and reconversion to hydrogen.

For local distribution, the two main modes for transporting hydrogen are trucks and pipelines. The best option will depend on volume, distance and end-user needs (IEA, 2019). While trucks carrying hydrogen gas distribute most hydrogen today, this is a relatively expensive option. As the distribution distance increases, pipelines become increasingly cost-competitive with trucks.

5.2.4 Infrastructure

Developing a new hydrogen value chain depends on successfully building and connecting production, transmission, distribution, storage and end-use infrastructure. This would require coordinated investment by many different market participants, which could be challenging to implement. Investment in infrastructure is generally recognised as one of the necessary and vital solutions to the development of a hydrogen 'ecosystem'.

The need to develop infrastructure is a challenge faced by all countries aiming to develop a hydrogen economy, as it will influence the pace and scale of hydrogen deployment. Since large-scale infrastructure such as pipelines and port terminals take several years at least to plan and implement, immediate action is needed to develop the infrastructure.

In the interim, the existing infrastructure for natural gas could be a good starting point. There are about 4600 km of dedicated hydrogen transmission pipelines operating in north-west Europe, Russia and the USA (IRENA, 2022a), whereas there are almost 3 million km of natural gas transmission pipelines globally, around 400 billion m^3 of underground storage capacity and an established infrastructure for international liquefied natural gas (LNG) shipping (IEA, 2019). If some of this infrastructure could be used for hydrogen transport and distribution, it could provide a major boost to the development of hydrogen. There may be technical constraints such as material compatibility of the existing network with hydrogen.

The extent to which hydrogen can make use of an existing natural gas infrastructure has been investigated. A project by Carbon Limits and DNV (2021), called Re-Stream, concluded that most European offshore pipelines can be reused for pure hydrogen based on the current state of knowledge and standards. For onshore pipelines, about 70% of the total pipeline length could be reused, based on pipelines in Europe. The remaining 30% could conceivably be reused, although more testing and/or updated standards are required. Figure 19 illustrates the pipelines that can be reused in Europe according to the Re-Stream project. Another EHB analysis has found that, by repurposing existing natural gas infrastructure, a pan-European hydrogen infrastructure network with a length of almost 53,000 km could be established by 2040 (van Rossumand and others, 2022). In various countries across Europe and North America, projects have been set up to explore the use of gas grids for hydrogen distribution (DNV, 2022).

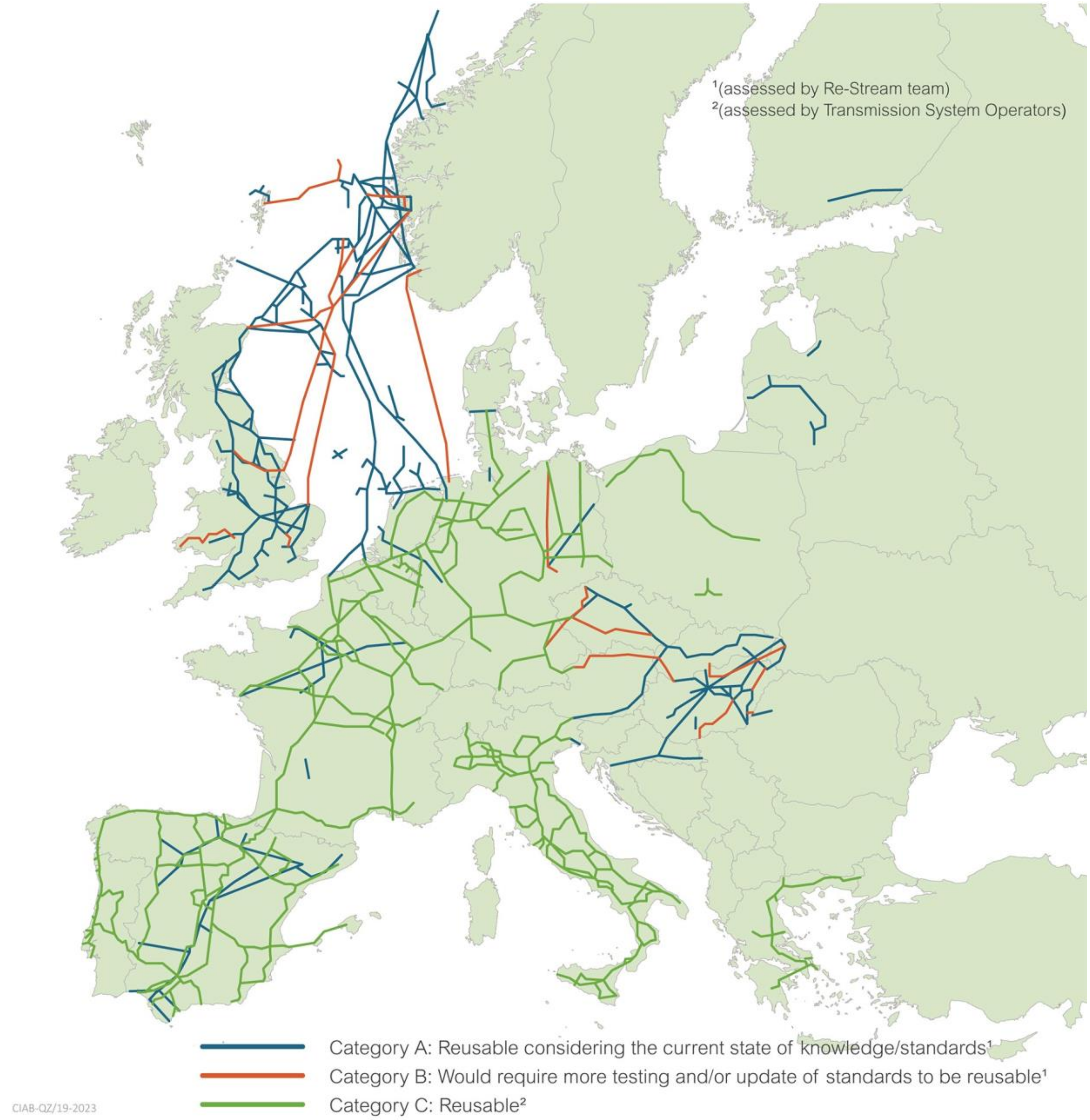

Figure 19 Assessment of the reuse of the current pipeline network in Europe for hydrogen (Carbon Limited and DNV, 2021)

In addition, the LNG facilities at ports can be used for hydrogen import/export. Several such facilities recently built, or under construction, in Europe for LNG import can be converted for hydrogen use. In Australia, the Future Energy Exports Cooperative Research Centre is established and aims to build on Australia's knowledge base, capability, infrastructure and existing LNG supply industry to enable Australia to become a leading global hydrogen exporter.

5.2.5 Safety issues

Risk perception will be an important factor in the acceptance of hydrogen use. As it is such a small molecule, hydrogen leaks easily, especially from high-pressure environments. The leaks are difficult to detect as hydrogen is a non-toxic, odourless and colourless gas in ambient conditions. It dissipates rapidly when released, allowing for the relatively rapid dispersal of the fuel if it leaks in an open space. Hydrogen has the widest range of flammability, fastest flame propagation speed, and lowest ignition energy, making it difficult to use safely. Ignition of accidental releases of hydrogen can result in fires and explosions when air is mixed with a hydrogen volume fraction of only 4%. Therefore, ensuring safety is the highest priority for hydrogen utilisation. Table 11 compares the properties and hazards of hydrogen with those of natural gas (methane).

TABLE 11 COMPARISON OF PROPERTIES AND HAZARDS OF HYDROGEN AND NATURAL GAS (MODIFIED FROM DNV, 2022)

Gaseous (compressed) hydrogen		
Density	Release rate	Hydrogen is 1/8 of the density of methane, so in equivalent conditions, the volumetric flow rate of hydrogen is 2.8 times that of methane; conversely, the mass flow of methane is 2.8 times that of hydrogen. Isolated hydrogen pressure systems will depressurise faster than for methane, but larger flammable clouds may result. The energy flow of hydrogen and methane (like for like) is similar.
	Dispersion and gas build-up	Hydrogen is more buoyant than methane and has a strong tendency to move upwards, an aspect that can be used to minimise the potential for hazardous concentrations to develop.
Ignitability	Ignition energy	The minimum spark energy required to ignite a hydrogen-air mixture is less than 1/10 f that required for methane or natural gas. However, this does not necessarily increase the chance of ignition significantly. Equipment approved for use in hydrogen systems is readily available.
Combustion	Flammability	Concentrations of hydrogen in the air between 4–75% are flammable, a much wider range than for natural gas (5–15%). This increases the likelihood of ignition.
	Fire	Released compressed hydrogen gas will burn as a jet fire, but the jet fire hazards are similar for hydrogen and natural gas.
	Explosion	The explosion potential for hydrogen is much greater than methane as at higher concentrations in air (>20%) the speed of the flame is much higher. In addition, hydrogen-air mixtures can undergo a transition to detonate in realistic conditions, which would not occur with methane.
Liquid hydrogen (additional to compressed gas hazards)		
Temperature	Liquefaction	In many ways, liquid hydrogen is a cryogenic liquid like liquefied natural gas (LNG). But due to the lower temperature, spillages can liquefy and solidify air from the atmosphere. The resulting mix of liquid hydrogen and liquid/solid air has exploded in small-scale field experiments. This does not occur with LNG.
Density	Buoyancy and dispersion	As liquid hydrogen vapourises and mixes with air, it cools the air, increasing its density. Consequently, a hydrogen air cloud produced from a liquid hydrogen release will not be as strongly buoyant as in a gaseous hydrogen case. This also occurs with LNG but the LNG-air mixture will be denser than air.

The small molecular volume means hydrogen can easily diffuse into steel and other metals, resulting in reduced material strength and embrittlement. Hydrogen can also easily enter pipe gaps to form local stresses and cause leakage. The challenge is to identify appropriate materials and add safety features in the design of safe hydrogen systems.

A key element of managing hydrogen safety is to control gas dispersion and build-up to prevent the concentration of hydrogen in air from exceeding 15% (DNV, 2022). Consequently, adequate ventilation and leak detection are important elements in the design of safe hydrogen systems. As hydrogen burns with an almost invisible flame, special flame detectors are required. Based on current technical understanding and experience from previous designs and operation of hydrogen systems, it is reasonable to expect that hydrogen facilities can be engineered that are as least as safe as widely accepted natural gas facilities.

6 INTERNATIONAL HYDROGEN TRADE

6.1 KEY MESSAGES

Currently, the projected renewable hydrogen capacity of many countries falls short of their targets, and the gap between existing hydrogen demand and projected renewable hydrogen production capacity is even greater. Thus, diverse sources for hydrogen production are required that will be linked to the resources available in a region.

- For countries such as China and India, hydrogen production from coal gasification with CCUS will be vital to meet increasing domestic demand.
- Over time, opportunities for international trade will evolve as some countries will have restricted domestic capability to produce hydrogen due to limitations on their available resources, options for low cost/low carbon hydrogen production, and/or options for cost-competitive CCUS. Importing countries are likely to include Japan, South Korea and Europe.
- Other countries will not face such barriers and can potentially produce hydrogen at low cost but have low domestic demand. These may include Australia, Chile, Indonesia, Malaysia, the Middle East, Russia and South Africa.

Delivery infrastructure requirements and resources will vary by region and type of market – for example, urban, interstate or cross-border, including seaborne. Infrastructure options and the associated transport economics will also evolve with growth in the demand for hydrogen and as delivery technologies develop and improve.

International trade in hydrogen is emerging and will increase. In particular, hydrogen trade in the form of ammonia for use as a clean fuel will see a significant increase in the near term.

6.2 REGIONAL VARIATIONS

The strong commitment of governments worldwide to decarbonise has stimulated an increasing momentum in the hydrogen industry. The development of a variety of national hydrogen development strategies and targets means that there are many approaches to the challenge. The following sections examine the regional variations in terms of demand and supply, available resources, infrastructure, and overall approach to hydrogen and activities.

6.2.1 Europe

Europe is taking a lead in developing a hydrogen economy, with a huge investment plan and commitment to using low-emission hydrogen. As discussed in Section 2.2, the EU target is to have 20 MtH_2/y by 2030 and 13–14% of hydrogen in the energy mix by 2050. Ambitious targets have also been set by individual governments including Germany, Italy and the UK. The Western European region as a whole favours renewable hydrogen, while several countries such as Norway and the UK would also exploit fossil fuel-based low-emission hydrogen. Most European countries lack fossil fuel resources, in particular natural gas, and many countries are currently diversifying from a dependency on natural gas. Some European countries are rich in renewable resources such as Greece, Iceland (geothermal), Italy, Norway, Spain and Turkey, and could potentially become suppliers of renewable hydrogen to the region. Depending on offshore wind technology developments, other countries such as the UK could produce renewable hydrogen to supply part of their own requirements. The domestic renewable hydrogen supply potential in the EU and UK from dedicated renewables is estimated to be 450 TWh in 2030, and 4000 TWh in 2050 (Wang and others, 2021). This potential already takes into account the growing need for renewable electricity for direct consumption, land availability, environmental considerations and installation rates. Realising this potential would require a rapid, vast expansion of wind and solar capacity, beyond what is needed for direct electricity demand and corresponding to cumulative installed capacities of 1900 GW in 2030, and 4500 GW in 2050.

Producing such quantities of renewable hydrogen within the EU and UK requires an accelerated expansion of renewable installed capacity beyond that currently planned. The 2030 installed capacity figure represents a more than doubling of current cumulative National Energy and Climate Plan targets. However, the overall capacity of renewable energy in the continent is likely to be insufficient to produce hydrogen at the scale required to meet the region's growing demand. Further, there is a large shortfall between the EU's 2030 target of 65–100 GW of installed electrolyser capacity and the 22 GW of announced proposals (Weichenhain and others, 2022; Burgess, 2021a). Consequently, Europe will rely on imports to meet its demand. In addition, the high cost of natural gas, electricity and labour means the production cost of hydrogen in Europe will generally be higher than in most other regions. Hydrogen imports from neighbouring regions such as North Africa by pipelines, and potentially from the Middle East could be more cost-efficient to complement domestic hydrogen production and to support the security of European supply (Wang and others, 2021).

6.2.2 Asia-Pacific

The use of low-emission hydrogen for transport, power generation, heating and blending in the gas network is being explored in much of the Asia-Pacific region, including Australia, China, Japan, New Zealand, Singapore and South Korea. The FCEV market is advancing the most rapidly, with South Korea, China and Japan being in the top four largest FCEV markets. However, there are large differences within the region regarding available energy resources, the overall approach to hydrogen, and potential future demand and supply. For many countries in the region, developing a hydrogen economy is not a priority.

Japan

Japan was the first country to adopt a national hydrogen strategy and it aims to become the world's first 'hydrogen society' through the widespread use of hydrogen across all sectors of the economy. The plan is backed by considerable government investment in hydrogen technologies and infrastructure. The aim is to expand hydrogen use to 3 Mt/y in 2030 and 20 Mt/y by 2050 (METI, 2022). Japan has also targeted the use of ammonia as a fuel for power generation and shipping. As an island country with limited fossil energy resources, Japan relies on imports for almost all its oil, natural gas and coal. Japan also has an ambitious target for renewable energy, approved by Japan's cabinet in

October 2021, whereby renewables should account for 36–38% of power supplies in 2030, double the level of 2019 and well above its previous 2030 target of 22–24% (Reuters, 2021). Japan also has a goal of 2050 to achieve carbon neutrality. However, the country's high population density and mountainous geography constrain the land available for developing renewable energy projects. According to Kikukawa (Reuters, 2021), an adviser to the government on energy policy, Japan is likely to miss its 2030 target for renewable power generation due to a lack of suitable sites. This means it is likely that Japan will need to import clean energy such as hydrogen and ammonia to meet its growing demand. Japan plans to import 0.3 MtH_2/y and 3 Mt/y of ammonia by 2030.

China

With a production capacity of 41 MtH_2/y and an annual output of over 33.4 MtH_2/y, China is the world's largest user and producer of hydrogen (Sheng, 2022). China regards hydrogen as a strategic 'frontier technology' and aims to become a global leader in the field. China published its national strategy for hydrogen in March 2022, but some local policies and industry developments have already moved beyond the national strategy and its targets. Forty provinces and cities have set hydrogen development targets for 2025 for a hydrogen industry valued at RMB960 billion, a total number of FCEVs of 125,940, and 909 hydrogen refuelling stations (Sheng, 2022). Currently, China has the world's third-largest FCEV fleet (after South Korea and the USA) and leads the world in the deployment of FC trucks and buses. The major steelmaking companies are developing hydrogen-based DRI production for deployment at scale by 2035 (IEA, 2021a). In addition to several projects that are under development to demonstrate technologies for decarbonising chemical and steelmaking processes using hydrogen, China has successfully tested small-scale ammonia-coal cofiring for power generation. Consequently, this is considered to be able to contribute to the decarbonisation of China's coal-fired fleet and can help China achieve its strategic goal of peak carbon emissions and longer-term carbon neutrality. China plans to increase its R&D work in developing ammonia cofiring technology with a higher ammonia ratio and at larger units, followed by the launch of demonstration projects in large coal-fired power plants. It is likely that the uptake of hydrogen will increase and accelerate rapidly in China. As hydrogen is envisaged to play a critical role in decarbonising China's heavy industry, medium and heavy transport, building heating and other sectors, the potential hydrogen market in China is huge with demand projected to reach 130 MtH_2 in 2060.

Compared to European strategies that aim to leverage low-emission hydrogen for rapid and deep decarbonisation, China's policy support for hydrogen remains focused on general industry development first and cleaning it second as part of its broader push for industrial upgrading, technological innovation, and a long-term transition towards clean energy. Also, the short-term target set in its national strategy for renewable hydrogen production capacity is conservative at 100,000–200,000 tH_2/y (6.7 TWh/y) by 2025, compared to Germany's plan for over 418,353 tH_2/y (or 14 TWh/y) by 2025 (Brown and Grünberg, 2022). However, local governments, research institutes, and industries are racing to develop hydrogen technology and more ambitious markets than the conservative national policy targets. As of June 2022, there have been more than 200 renewable hydrogen projects announced or under development; 18 of them with a total capacity of 30,000 tH_2/y have started operation and around 30 are under construction in China (Sheng, 2022). Figure 20 shows some of the major renewable hydrogen projects under development in China. Most of the projects being developed are in North and Northwest China. As the major consumers are located in eastern and southeast China infrastructure is needed to transport the hydrogen from producing regions to demand centres.

Figure 20 **Some of the major renewable hydrogen projects under development in China (Brown and Grünberg, 2022)**

Coal is the main fuel to drive economic development in China as there are vast coal reserves but limited oil and gas resources. Hydrogen production in China today is predominantly fossil fuel-based with coal accounting for 56.5% and gas for 22.3% (Sheng, 2022). Hydrogen by-products from industrial processes make up most of the rest. Currently, there are no fossil fuels with CCUS projects being developed in China for low-emission hydrogen production. China also has enormous renewable energy potential, especially solar and wind in North and Northwest China. China's 14th Five-Year Plan

(FYP, 2021-2025) published in early 2022 sets targets to produce 25% of its energy from non-fossil sources by 2030, and to meet more than 50% of the incremental electricity consumption with new renewable generation. These targets will require China to scale up renewable power by 150 TWh/y (Energy Mix, 2022). China is the world's largest solar and wind energy producer, which increased capacity by 100 TWh/y during the previous FYP and recorded a 255 TWh rise in 2021 reaching a total installed renewable generation capacity of 1063 GW (Energy Mix, 2022; Yin and Yep, 2022). China is likely to exceed the short-term targets for renewable power generation and renewable hydrogen production capacity. Given the large consumption of hydrogen and the potentially rapidly growing demand in China, and due to the huge gap between its overall demand and low-emission hydrogen production capacity, China will face big challenges to meet its demand for low-emission hydrogen, including that of logistics. China will continue to rely on coal-based hydrogen production in the coming years and the inclusion of CCUS in coal-based hydrogen production is vital for China to meet its climate change mitigation goals. It is unlikely that China will become a major exporter of low-emission hydrogen, nor is this planned in national policy which prioritises self-sufficiency by building out a domestic supply chain.

Australia

The Australian hydrogen strategy places more emphasis on low-emission hydrogen production and export while also promoting its domestic use in transport and clean ammonia production. Australia possesses enormous solar energy resources and abundant coal and natural gas resources, providing the country with tremendous potential to produce low-emission hydrogen for domestic use and for export. Current hydrogen demand in Australia is small, and the growth in domestic demand is generally seen as limited. However, the country's potential to produce low-emission hydrogen and ammonia affordably will enable it to become a major player globally in the production and supply of clean fuels. Recognising this opportunity, the Australian government has invested in seven hydrogen hubs that centralise users geographically, thereby minimising infrastructure costs (IEA. 2021a). Currently, nine renewable hydrogen production projects with a total capacity of more than 1 GW are under development or are in the early stages.

When combined with CCUS, coal could provide Australia with a cheap source for low-emission hydrogen production. The first demonstration plant for producing hydrogen from coal, as part of the HESC Pilot Project led by HySTRA, started operation in March 2021 and successfully produced 99.999% pure hydrogen gas through the gasification of Latrobe Valley lignite (HESC, 2022). The hydrogen produced was liquefied at Hastings, Australia's first hydrogen liquefaction plant. The liquid hydrogen was stored in a container which was loaded onto Suiso Frontier, a purpose-built ocean-going liquid hydrogen carrier ship. The Suiso Frontier left Hastings in late January 2022 carrying the world's first trans-ocean shipment of liquid hydrogen and arrived at the Port of Kobe, Japan four weeks later marking the successful completion of the pilot project. The facility has not been fitted with CCUS in its first phase, but carbon offsets have been purchased to mitigate emissions from the pilot project. It will be retrofitted with CCUS capability by 2030, subject to a successful demonstration of the economic viability of transporting liquid hydrogen from Australia to Japan.

In the Glencore Surat Hydrogen project, Glencore (2023) of Australia is investing in studies of commercial-scale hydrogen and ammonia production in Queensland for export to customers overseas. Glencore aims to achieve NZE by 2050 and sees hydrogen as one potential pathway to an NZE future. Glencore will invest AU$40 million to fund studies into the use of coal as feedstock to produce hydrogen and ammonia with CCUS. The project is currently at the pre-feasibility study level, and Glencore expects to reach a final investment decision in 2029.

Several SMR-combined CCUS projects for low-emission hydrogen production from natural gas are also under development in Australia. The HESC project is an example of the collaboration between the governments and industry partners of Japan, Australia and Victoria. The Australian government has also been developing international partnerships with Singapore, Germany, Japan, South Korea and the UK to explore opportunities to export low-emission hydrogen to them. In March 2022, Germany's largest energy group, E.ON signed a memorandum of understanding with Australian Fortescue Future Industries (FFI) to explore the shipping of renewable hydrogen to Europe to help reduce dependence on Russian gas (Steitz, 2022). The companies said in a statement that they will look at ways to ship up to 5 MtH_2/y to Europe by 2030, with the first shipments possibly taking place in 2024.

South Korea

South Korea also has strong ambitions to create a hydrogen economy. The country leads in the production and deployment of FCEVs and aims to increase the number of passenger FCEVs from 10,000 in 2020 to 200,000 by 2025 (IRENA, 2022a). It also plans to use hydrogen to power 10% of the regions by 2030 and 30% by 2040 and expects hydrogen to have a 33% share of total energy consumption by 2050. South Korea is a global leader in large-scale stationary FCs for power generation and has also set a target to cofire ammonia with coal to partly decarbonise its coal power generation by 2030. This means that South Korea, like Japan, will be a major demand centre for low-emission hydrogen and ammonia. South Korea's hydrogen plan targets nearly 2 Mt/y of low-emission hydrogen imports by 2030 (IEA, 2022a).

South Korea relies on imports to meet over 90% of its energy needs. The government has committed to increasing the share of renewable electricity to 20% by 2030 and 30–35% by 2040 (IEA, 2020). However, the country's mountainous topography, high population density and the absence of transborder interconnections create challenges for the acceleration of renewable energy deployment. Currently, the share of renewable energy in South Korea is low as non-hydro renewable energy accounted for only 5.9% of the country's electricity generation in 2020 (Statista, 2022a). The lack of natural resources and the challenge of achieving the targeted renewable electricity generation mean that South Korea will need to import low-emission hydrogen and ammonia to meet its demand. The country is exploring the import of hydrogen and ammonia from various supplier countries such as Australia and the Gulf States.

India

India launched its National Hydrogen Mission (NHM) in August 2021, with the ambition of becoming 'a global hub for green hydrogen production and export' and aims to have 5 Mt/y of renewable hydrogen capacity by 2030 (PIB, 2022a). India is the world's largest producer of steel using the DRI route, consuming 20% of the 7 MtH_2 used in India in 2020 (IEA, 2021a). The government is now considering making it mandatory for refineries and fertiliser plants to use a certain amount of renewable hydrogen. Hydrogen use in India is expected to rise substantially in the next decade as population growth and economic development create an increased demand for ammonia (for food production) and steel (for new infrastructure).

Almost all hydrogen demand in India is met through domestic production based on unabated fossil fuels, with natural gas accounting for 75% and coal for 15%; by-products from refineries make up the rest (IEA, 2021a). India has enormous renewable energy potential, which, if developed, would enable it to decarbonise industry using low-emission hydrogen while also reducing its dependency on imported natural gas and ammonia. India has ambitious targets for renewable power; the aim was to install 500 GW of renewable capacity (although this has been dropped) and to meet 50% of its electricity needs from renewable sources by 2030 (Singh, 2022). As of July 2022, India's installed renewable energy capacity (including hydropower) was 161.28 GW (compared to a 2022 target of 175 GW), representing almost 40% of the total installed power capacity (IBEF, 2022). Despite the considerable growth in renewable power in the past decade, a detailed analysis of the country's power market by GlobalData has found that although India is likely to achieve its 2022 target for installed renewable power capacity, it may miss out on the solar-specific target, and subsequently fall short of the 2030 target by more than 104 GW (GlobalData Energy, 2022).

India is also facing significant challenges to deploy electrolysers at scale and build the necessary infrastructure to connect hydrogen production regions to major demand centres and ports to help the latter become major import/export hubs. According to India Hydrogen Alliance, to produce 3 Mt/y of renewable hydrogen by 2030, India will require 15 GW of electrolyser capacity and 30 GW of renewable energy (Koundal, 2021). Five major renewable hydrogen projects have been announced in India to date. If all of them materialise, this would add a cumulative production capacity of 1.8 MtH_2/y by 2030 (Gupta, 2022). The competition for renewable power to meet the nation's renewable electricity generation target and to support hydrogen production, the lack of installed electrolysers capacity and the necessary infrastructure means that India is unlikely to meet its demand with renewable hydrogen in the short- to medium-term and will need to continue to produce hydrogen from fossil fuels and/or even rely on imports to meet the growing demand. Like China, India has abundant coal reserves but limited oil and gas resources. This factor, coupled with high gas prices, means that coal with CCUS can provide India with a source for cost-competitive low-emission hydrogen production.

6.2.3 Americas

In the Americas, the demand for low-emission hydrogen varies by country, but in general, significant hydrogen uptake is likely in the transport sector. Most countries in the Americas that are developing a hydrogen industry are considering the potential global market for low-emission hydrogen export.

USA

The USA is a large producer and consumer of hydrogen at 11 MtH_2/y (consumption). The US government is a strong supporter of hydrogen, with a focus on cost and performance targets that can enable the adoption of hydrogen technologies, rather than setting deployment targets. In 2016, the US Department of Energy (USDOE) introduced the H2@Scale initiative to enable affordable and low-emission hydrogen from diverse domestic resources including renewables, nuclear energy and fossil fuels across various end-use sectors including transport, metal refining, power generation, heating, ammonia and fertilisers (IEA, 2021a). The USDOE has invested heavily over the years in R&D on hydrogen-related technologies. For example, in June 2021, the DOE launched the Hydrogen Energy EarthShot initiative which aims to slash the cost of low-emission hydrogen by 80% to 1.00 $/kgH_2$ by 2030. At this low price, a fivefold increase in demand for low-emission hydrogen is expected. In 2022 the USA established the Bipartisan Infrastructure Law, which includes $8 billion for the creation of regional low-emission hydrogen hubs, aiming to create jobs and expand the use of low-emission hydrogen. A new tax credit has been released to support low-emission hydrogen. Hydrogen with lifecycle greenhouse gas emissions of less than 0.45 $kgCO_{2\text{-eq}}/kgH_2$ will be eligible for the full 3 $/kgH_2$ credit. Thus, the lower the carbon content of the hydrogen produced the higher will be the tax credit received by producers (WEC, 2022).

The demand for low-emission hydrogen in the USA is set to increase dramatically. Today, it is the second largest global market for FCEV, led by California. The California Fuel Cell Partnership has a target for one million FCEVs in the state by 2030. Elsewhere in the USA, low-emission hydrogen uptake opportunities are emerging in the petrochemical and chemical sector.

Currently, around 80% of US hydrogen production is based on natural gas SMR. Almost all the remainder comes from hydrogen as a by-product in refineries and the petrochemical industry (IEA, 2021a). As of June 2021, 17 MW of electrolysers for hydrogen production were operational in the USA, 34 with a total of 1.4 GW of capacity in the pipeline, with 300 MW under construction or with funding committed and another 120 MW were at earlier stages of development and could be online by 2030 (USDOE, 2021). Based on company proposals and projections, up to 13.5 GW of electrolysers could be deployed by 2030, which falls short of the 44 GW of electrolysis capacity by 2030 in the IEA's APS (IEA, 2021a) and is insufficient to meet the demand. However, the USA is leading the production of fossil fuel-based low-emission hydrogen, particularly for ammonia production. In 2021, US production from fossil fuels with CCUS was 0.23 MtH_2/y, around one-third of global production capacity. The largest project under construction in the world is the Wabash Valley Resources Project in Indiana which could have a production capacity of over 0.3 MtH_2/y. With the technologies and plentiful reserves, coal could prove to be a low-cost source for low-emission hydrogen production in the USA.

Canada

The Canadian hydrogen strategy addresses the role of hydrogen across a wide range of end-use sectors, including industry, refining, transport, power and buildings. Canada sees the range of available domestic energy resources such as oil and gas (coupled with CCUS), nuclear and renewable energy as a great opportunity to diversify the mix of technologies to produce hydrogen but will not use coal for hydrogen production, although it is a coal exporter. Based on these vast resources, Canada has an ambitious goal to become a major exporter of hydrogen and hydrogen-based fuels, and hydrogen technologies (IEA, 2021a). In August 2022, Canada and Germany signed a joint declaration of intent to establish a Canada-Germany Hydrogen Alliance, which will facilitate the trade of hydrogen and its derivatives between the two countries with a target for initial exports to begin in 2025 (NRCAN, 2022). In addition, Canada announced a Credit and Clean Hydrogen Investment Tax Credit as part of its 2022 budget. Details on the level of support for different production pathways are yet to be agreed (as of January 2023). Canada sees limited growth in domestic demand for hydrogen but could be a major player in international hydrogen supply.

Latin America

Latin American countries consumed 3.5 MtH_2 in 2020, 2.5 Mt H_2 of which was used in industry and the rest in refining. Around 90% of the production was from unabated natural gas and the rest was a by-product from refineries (IEA, 2021a). Low-emission hydrogen uptake in Latin America is likely to first take place in industry and transport, while agriculture may present one of the largest consumers of hydrogen for fertiliser production in the long term.

Latin America is rich in renewable resources, and some countries also have significant oil, gas and coal reserves. Although some have set targets to develop local supply and demand, many Latin American counties are seeking to export low-emission hydrogen, especially to the European market. Therefore, the focus has been on the production of hydrogen using renewable power or natural gas reforming with CCUS. However, overall, the total projects in the pipeline fall far short of the targeted capacities. It is unlikely that countries from this region can become major clean fuel exporters in the short or medium term.

6.2.4 Middle East

Around 11 Mt of hydrogen was consumed in the Middle East in 2020, mostly for refining, chemicals and steel production (IEA, 2021a). Natural gas accounts for close to 90% of production, and the remainder is a by-product from refineries. The Middle East has enormous oil and gas reserves, excellent renewable resources (particularly solar) and vast areas of desert that can enable low-emission hydrogen production at a significantly lower cost than in most parts of the world. Middle Eastern countries are exploring hydrogen production from both renewables and natural gas with CCUS. Governments in the region envision exporting their low-emission hydrogen and ammonia to potential international markets; various bilateral agreements with countries such as Germany, Japan and South Korea have been announced. Several mega projects are under development in the region to produce low-emission hydrogen, so the Middle East could become a major supplier of clean fuel.

Saudi Arabia's Nationally Determined Contribution (updated in October 2021) states the country's solar and wind resources can be used for hydrogen production via electrolysis (NDC Registry, 2021). In addition, due to the abundance of natural resources, underground carbon storage capacity and CCUS technology expertise the country has the potential to become a world-leading producer of hydrogen from natural gas. The captured CO_2 could be used by industry if there is sufficient demand for it or injected into oil reservoirs for enhanced oil recovery.

The UAE is investing in the development of low-emission hydrogen value chains to accelerate its leadership in emerging low-carbon fuel production and deliver the UAE's Hydrogen Leadership Roadmap to position the country as a competitive exporter of clean hydrogen. Its Nationally Determined Contribution (updated in September 2022) also reports that there are significant opportunities to use nuclear energy for hydrogen generation (NDC Registry, 2022).

Oman aims to become one of the largest renewable hydrogen producers and exporters globally, targeting production of over 1 Mt/y by 2030 rising to 3.75 Mt/y in 2040 and 8.5 Mt/y by 2050. In November 2022 up to six plots of land were offered at auction on which to build fully integrated renewable hydrogen projects. These include the renewable power supply, electrolyser capacity and any associated infrastructure required to process the hydrogen into another product, such as methanol or ammonia (Paldaviciute, 2022; Parkes, 2022).

6.2.5 Africa

African countries consume close to 3 MtH_2/y, 70% of which is used in the chemicals sector, mainly for fertiliser production (IEA, 2021a). Virtually all current hydrogen production in Africa is based on fossil fuels. Africa has vast renewable potential, and a great opportunity to develop a hydrogen sector with experience in ammonia production using electrolysis. Several countries such as South Africa and Mozambique have abundant coal reserves while others such as Algeria, Angola and Nigeria are rich in oil and/or gas. The development of local production capacity could reduce imports of fertilisers, provide power for isolated areas and improve energy access, power transport, and contribute to strengthening the energy and economic independence of African countries. Another economic advantage of developing hydrogen could come from exports. Africa has considerable potential to generate low-cost, low-emission hydrogen. Currently, North African countries are better positioned for exports, mainly to Europe. Several bilateral partnerships are emerging between African countries and potential importers in Europe and Asia (WEC, 2022). Morocco leads the way with its Green Hydrogen Cluster. With the dual objectives of collaborating in technology development and positioning Morocco as a potential exporting hub, the government has been building international partnerships with countries such as Germany and Portugal (IEA, 2021a).

However, Africa faces significant challenges in terms of access to energy, lack of infrastructure, and inadequate technological and skills capacities. With nearly 600 million people in Africa without access to electricity, significant power capacity building, both renewable and fossil fuelled, is required to lift people out of poverty, so they may not be ready to produce and use hydrogen at scale in the short term.

6.3 PROSPECTS FOR INTERNATIONAL HYDROGEN TRADE

As the momentum of developing and deploying hydrogen continues to grow, there will be increasing demand worldwide for low-emission hydrogen and hydrogen-based fuels. Due to differing market activities and opportunities, there are great regional differences as discussed above. Some countries aim to scale up the use of low-emission hydrogen significantly to achieve decarbonisation goals but lack the domestic capacity to cost-effectively produce the necessary volumes. Other countries have abundant energy resources to produce renewable or fossil fuel-based low-emission hydrogen but have low domestic hydrogen demand. Therefore, there is a need for a global supply chain to enable a hydrogen trade that can satisfy the increasing demand of importing countries and allow exporters to earn revenue. The world's first shipment of 40 tonnes of fossil fuel-based low-emission ammonia from Saudi Arabia to Japan in 2020, and the first shipment of liquefied hydrogen from Australia to Japan in February 2022 are key milestones in the development of an international market for hydrogen and hydrogen-derived fuels.

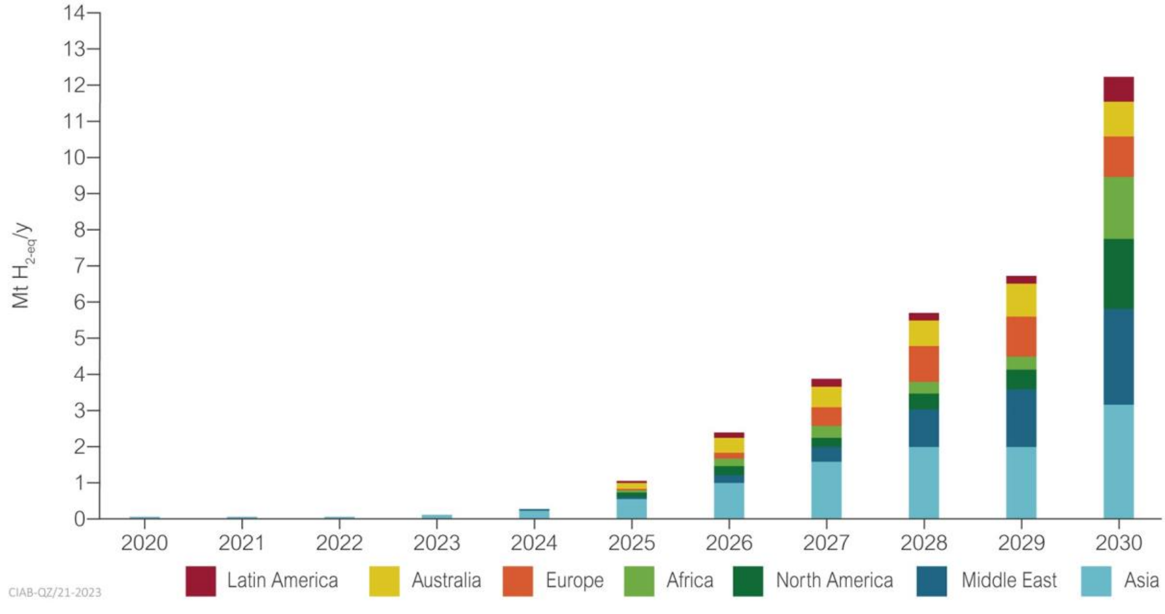

Figure 21 Export-oriented hydrogen project plans (IEA, 2022a)

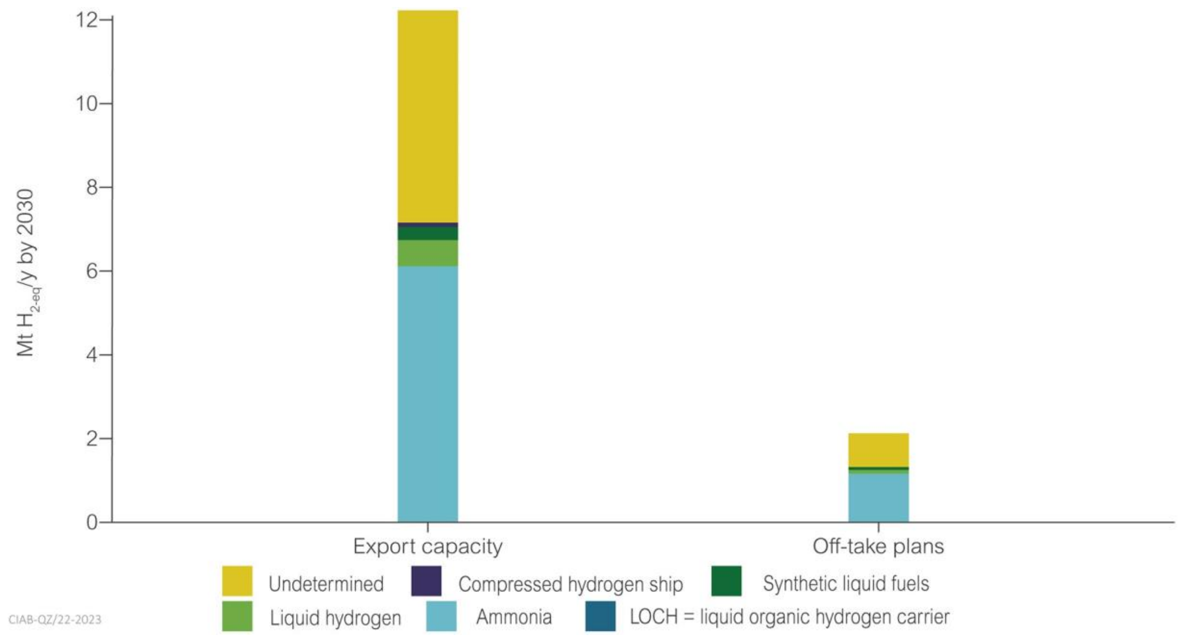

Figure 22 Planned hydrogen export by carriers by 2030 (IEA, 2022a)

According to the IEA's (2022) estimate shown in Figure 21, based on the export-oriented projects under development, low-emission hydrogen exports could reach 12 MtH_2/y by 2030, with 2.4 MtH_2/y planned to come online by 2026 (IEA, 2022a). However, to meet the government hydrogen import targets more than 15 MtH_2/y is required by 2030 (EU 10 Mt/y, Japan 3 Mt/y and South Korea 2 Mt/y). Most of the projects are at an early stage of development; projects representing only 0.2 MtH_2/y have reached a final investment decision or beyond. For the projects that have identified a hydrogen carrier, most choose ammonia as shown in Figure 22. Currently, more countries are exploring exporting markets than those seeking suppliers. Europe (particularly Germany and the Netherlands), Japan and South Korea are identified as major demand centres and importers of low-emission hydrogen by 2030 and beyond. Table 12 shows the regional breakdown of the planned projects with off-take agreements or with intended destinations and the government-targeted hydrogen import. Of the planned 2.4 MtH_2/y imports to Asia by 2030, none is marked for South Korea, and only 0.7 MtH_2/y is marked for Japan compared to its 2030 target of importing 3 MtH_2/y. In Europe (including non-EU countries), 0.9 MtH_2/y by 2030 is marked for import into Europe from outside the EU and the rest is to be hydrogen traded between two European countries. This volume is far less than the EU import target of 10 MtH_2/y by 2030 (IEA, 2022a). Potential European importers are seeking hydrogen supply from North Africa by pipeline to minimise the total costs, but they are also exploring the possibility of importing hydrogen from other regions such as the Middle East and North America. Importing countries in Asia, especially Japan, are looking globally for exporters in, for example, Australia, the Middle East and North America. Therefore, opportunities exist for the international trade of low-emission hydrogen to evolve over time.

TABLE 12 REGIONAL BREAKDOWN OF THE PLANNED PROJECTS WITH INTENDED DESTINATIONS AND THE GOVERNMENT TARGETS IN 2030 (IEA, 2021A)

	Europe	Asia	
		Japan	South Korea
Planned imports, MtH_2	10	3	2
Destinated export projects, MtH_2	1.9	0.7	n/a
Total export-oriented projects with destinations, MtH_2	1.9	2.4	
Total export-oriented projects, MtH_2	12		

n/a not applicable

International trade in hydrogen is emerging and will increase in the coming years. In particular, hydrogen trade in the form of ammonia will grow significantly. Establishing a global hydrogen market and supply chain is required but it faces several challenges including reducing production and transport costs, building hydrogen transport and storage infrastructure, maintaining hydrogen purity and minimising its leakage. Investment is required to significantly expand existing infrastructure and to build new, to increase energy efficiency and to develop new technologies. In particular:

- ships and barges for the safe transport of liquid hydrogen;
- repurposing existing gas grids and converting LNG infrastructure at port terminals for liquid hydrogen use; and
- overcoming technical concerns related to long-distance transmission by pipeline, such as embrittlement of steel and welds, hydrogen leaks and inadequate compression.

Infrastructure needs for transport and storage will vary by region and type of market – for example, urban, interstate or cross-border including seaborne. Infrastructure options and the associated transport economics will also evolve with growth in the demand for hydrogen, and with the advance and improvement of transport technologies.

Similarly, building national hydrogen delivery infrastructure will take time to develop and will likely include combinations of various technologies and delivery infrastructure.

The clean energy transition will include the development of a new hydrogen export industry, leveraging global collaborations on hydrogen infrastructure to inform investment and mutually beneficial trading opportunities. This approach is being actively explored by exporters in Australia, Canada and the Middle East and importers in Germany, Japan and South Korea.

7 MEETING THE DEMAND

7.1 KEY MESSAGES

Meeting the short- to long-term demand targets for hydrogen is a huge challenge requiring rapid scaling up of hydrogen production capacity. The global demand for low-emission hydrogen cannot be met by renewable hydrogen production, at least in the short to medium term, for various reasons:

- The large gap between the installed renewable hydrogen production capacity and the capacity required to meet governments targets.
- The insufficient renewable power generation capacity to support large-scale renewable hydrogen production whilst meeting the direct electricity need.
- The electrolyser production capacity limitations.
- Supply issues of some key materials for electrolyser manufacture.

In addition, the current cost of hydrogen is very high which is the main barrier to its widespread application. Low-emission hydrogen production from coal and gas with CCUS is essential to fill the supply gap. Hydrogen produced from coal gasification with CCUS costs significantly less than renewable electrolytic hydrogen. This economic advantage will continue to 2030 or beyond. Therefore, hydrogen from coal with CCUS can improve the economic viability of low-emission hydrogen use, enable its early and wider deployment, and bridge the transition towards renewable hydrogen use in the longer term.

Although many new hydrogen projects will be located in industrial hubs with local end-users to minimise the cost, international trade of low-emission hydrogen will also be established to meet the global demand. The relative economics will depend largely on the resources available for the production, and transport infrastructure options and thus, delivery economics.

- For coal-dependent, large hydrogen-producing and consuming countries such as China and India, coal is the cheapest, indispensable source for hydrogen production.
- For importing countries such as Japan and South Korea low-emission hydrogen from coal offers a cost competitive choice, supplementing other options in meeting their demand.
- For exporting countries such as Australia and Indonesia which have access to substantial CCUS sites, producing low-emission hydrogen and its derivatives such as ammonia from coal can offer an income and provide importers with low-emission hydrogen at low and stable prices.

Moreover, renewable hydrogen needs a vast land area to host the wind and/or solar photovoltaic generation capacity. Where low-cost land or excellent renewable resources are not available, but coal and carbon storage sites are, clean hydrogen from coal with CCS will clearly be the best option.

Supportive policies to promote hydrogen development should take into account the advantages of local available resources, and complemented with international cooperation to establish a global value chain of low-emission hydrogen that is cost effective and reliable. By following a technology neutral approach coal will have a role to play in supporting the development of a hydrogen economy and a clean energy transition toward NZE.

Global demand for hydrogen is set to increase rapidly and substantially. Meeting the demand will be a challenge requiring the rapid scaling up of production capacity for hydrogen from 94 MtH_2/y in 2021 to potentially 130 MtH_2/y by 2030 and more than 500 MtH_2/y by 2050 (IEA, 2022a, 2021a). To put this demand into context, greenhouse gas emissions associated with current global hydrogen production are estimated at 900 Mt/y. Replacing that unabated hydrogen production with electrolysis would require more than 1000 GWe of electrolyser capacity. This is greater than today's total EU electricity generation capacity. Producing clean hydrogen from fossil fuels with CCUS is therefore a necessary additional option to be considered.

This chapter examines the main challenges to achieving this dramatic increase in hydrogen production:

- the gap between the electrolysis capacity in the project pipeline and the required capacity of installed electrolysers;
- the cost of hydrogen; and
- the implications of limitations of critical materials, water stress and available land for renewable hydrogen production.

The role of coal in helping to meet the demand for low-emission hydrogen to achieve NZE is examined.

7.2 RENEWABLE HYDROGEN PRODUCTION

7.2.1 Installed electrolyser capacity

The IEA (2022a) projects that global hydrogen demand in 2030 could reach 115 Mt/y in the Stated Policies Scenario (STEPS), or 130 Mt/y in the APS. Around 25% of this hydrogen (34 Mt) would be low-emission hydrogen used in new and traditional applications. Almost all current hydrogen production is based on unabated fossil fuels. In 2021, the production of low-emission hydrogen was less than 1 Mt (0.7%), the vast majority of which was low-emission hydrogen from fossil fuels with CCUS and only 0.035 MtH_2 was from the electrolysis of water (IEA, 2022a).

The total installed capacity of electrolysers reached 510 MW at the end of 2021, an increase of 210 MW or 70% from 2020. (IEA, 2022a). According to the IEA's Hydrogen Projects Database, the pipeline of low-emission hydrogen production projects that are under development has a total capacity of over 24 MtH_2/y by 2030 (IEA, 2022a). Europe leads in electrolytic hydrogen projects with 32% of the announced electrolyser capacity projects expected to be online by 2030. Australia is second with 28%. According to data from S&P Global (Burgess, 2021a), the proposed electrolyser projects due online by 2024 in the EU amounted to 5.2 GW, less than the EU target of 6 GW capacity by 2024 (producing up to 1 MtH_2/y of renewable hydrogen). There is a larger shortfall between the EU's 2030 target of 65–100 GW of installed electrolyser capacity (producing up to 10 MtH_2/y) and the 22 GW of announced projects as of July 2021. The IEA data also indicate that with the projects at advanced and early planning stages, renewable hydrogen production in Europe could reach close to 5 MtH_2/y by 2030, only 50% of the EU's 10 MtH_2/y target (IEA, 2022a).

Australia has enormous solar and wind resources, which in 2021, provided 22% of the country's total electricity generation (solar 12% and wind 10%) while coal provided 51% (DCCEEW, 2022). The scale of the renewable resources means that Australia has become a hotspot for electrolysis projects, mostly export oriented. Based on the IEA data, renewable hydrogen production capacity in Australia could reach 3 MtH_2/y by 2030 (IEA, 2022a). In addition, projects under development in Latin America, the Middle East and Africa, often for exports of hydrogen or ammonia to Europe and Asia, could bring over 4 MtH_2/y electrolytic hydrogen capacity by 2030. Many of the electrolyser projects were announced in or around 2021, accounting for 37% (in terms of production level) of the pipeline projects that are at very early stages of development (IEA, 2022a). Developing these projects will require several years to plan, finance and construct, and some may never materialise. There are many uncertainties, even for planned near-term projects. Some projects originally planned to become operational in 2022 and 2023 have been delayed due to problems securing finance. Some projects have been cancelled for other reasons. Even if the planned projects of 24 MtH_2/y are all realised by 2030, there is still a substantial gap between the projected production of 34 MtH_2/y in the APS, particularly a shortfall of almost 8 MtH_2/y for electrolytic hydrogen production (IEA, 2021a). Although there is still time for the development of new projects. Figure 23 compares today's low-emission hydrogen production capacity, the total production capacity by 2030 in the pipeline and the required capacity in IEA APS.

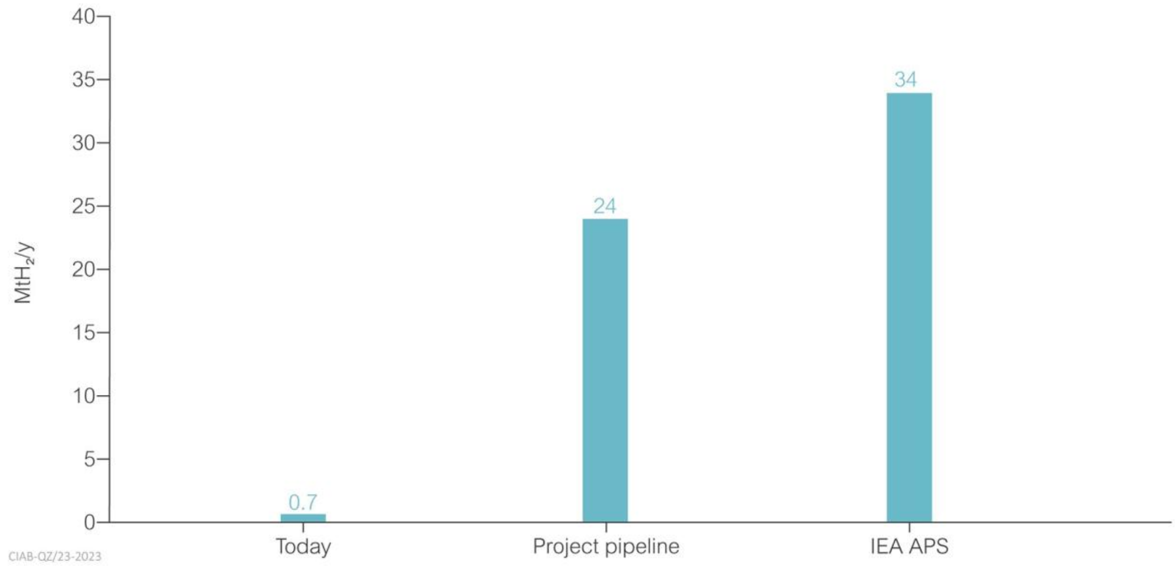

Figure 23 Low-emission hydrogen production capacity in the pipeline for 2030 compared with the required capacity in the IEA APS

7.2.2 Manufacturing of electrolysers

The majority (70%) of installed electrolysers use alkaline electrolysis, and PEM accounted for 25% of the total installed capacity in 2021 (IEA, 2022a). SOEC and anion exchange membrane electrolysis are emerging, but they represent only a minimum share of installed capacity. There is limited information available on the electrolysis technology selected for the announced and planned projects. However, it appears that the share of alkaline electrolysers in the total installed capacity will remain at around 60% for the next five years, and then decrease (IEA, 2022a).

The projected plans for renewable hydrogen depend on a massive scale-up of the manufacturing capacity of electrolysers. In 2021, the global manufacturing capacity for electrolysers was 8 GW/y, 85% of which was in two regions, Europe and China (IEA, 2022a). Alkaline electrolysers dominate with a 60% share of global manufacturing capacity. By 2030, they are projected to account for 64% of manufacturing capacity. This reflects the maturity of the technology compared to PEM which is expected to provide 22% of global production capacity in 2030 and SOEC just 4%. In Europe, there is 2.5 GW/y of electrolyser manufacturing capacity which needs to increase tenfold to achieve 25 GW/y by 2025 (Argus, 2022b). There is 16.48 GW of capacity addition by 2025 in announced projects and another 8 GW by 2030, but these companies will need direct and indirect support to achieve these targets. If all the projects are completed, the total would be slightly lower than the EU target of 10 MtH_2/y. This means that electrolysis manufacturing capacity could be the bottleneck, holding back production in Europe. Globally, according to an analysis by the US firm Jefferies, the supply of electrolysers could reach 47 GW by 2030, but 'could sit somewhere in the 30–40 GW range', compared to 54 GW of announced projects and 94 GW of what it calls 'pledged' projects (Collins, 2021). Jefferies concludes that "*there is unlikely to be sufficient supply even for the proposed projects out to 2030 even in the lowest demand scenario*". However, the IEA (2022a) is more optimistic about future electrolyser supply with its statistics showing that the cumulative output of electrolysers could reach around 270 GW by 2030, which is aligned with the combined policy targets of 145–190 GW for 2030.

The capital cost of an electrolysis unit (including the equipment, gas treatment, plant balancing, and engineering, procurement and construction cost) is high ranging between 1400–1770 $/kW. The lower end of the range applies to alkaline electrolysers and the upper one to PEM electrolysers (IEA, 2022a). The costs of SOEC will be much higher. Alkaline electrolysers produced in China can be cheaper than those produced by Western companies, with costs of around 750–1300 $/kW; some sources suggest a cost as low as 300 $/kW (IEA, 2022a; Collins, 2022b). However, Chinese electrolysers are typically less efficient and reliable than Western machines, and despite being much cheaper, would actually result in a higher levelised cost of hydrogen due to their lower efficiencies and shorter operating lifetimes, according to Collins (2022b). Substantial cost reductions through economies of scale and technological advances will be key to the large-scale deployment of electrolysers for hydrogen production. The cost of electrolysers produced in the West is expected to fall by 17% to ~1000 $/kW for alkaline electrolysers and 14% to ~1200 $/kW for PEM systems, while the costs of Chinese alkaline electrolysis may decline by 10% to 270 $/kW (Collins, 2022b).

However, scaling up the manufacture of electrolysers and reducing the costs will not be easy, especially for systems that rely on geologically scarce resources. Rising costs of raw materials, supply chain interruptions, recession and geopolitical instability could lead to higher costs of electrolysers in the short term and a slowdown in the planned expansion of manufacturing capacity. As described in Section 4.4, PEMs have several advantages over alkaline electrolysers as they respond more quickly to changes in power input, have a better flexibility with a large operational range, higher operating pressure and smaller footprint. The application of PEM is expected to increase, and its manufacturing capacity could reach around 15 GW/y by 2030 (Argus, 2022c; IEA, 2021a). However, PEM electrolysers require precious metals, specifically platinum (0.3 kg/MW) and iridium (0.7 kg/MW) for the catalysts (IEA, 2022c). Thus, large-scale PEM production would require a massive ramp-up of platinum and iridium mining (mainly in South Africa and Russia) as the current mining rates of platinum and iridium would only be sufficient to expand the annual production capacity of PEM by 3.0–7.5 GW. Although alkaline electrolysers do not require precious metals, current designs use 800–1000 kg/MW of nickel, 10,000 kg/MW of steel and 500 kg/MW of aluminium. If alkaline electrolysis dominates the market in 2030, the IEA NZE Scenario would imply a nickel demand of 72 Mt. Meanwhile, production of the emerging SOEC also requires nickel (150–200 kg/MW), as well as zirconium (40 kg/MW), lanthanum (20 kg/MW) and yttrium (<5 kg/MW). In addition, the conflict in Ukraine and the ensuing energy crisis have created uncertainty in Europe about the supply of steel, another key raw material for electrolysers. Furthermore, the current low level of market demand means that most electrolysers are still being manufactured using processes that involve little or no automation. This situation restricts manufacturers from making the necessary investments to streamline the production process (WEC, 2022). This adds to the cost and time needed to deploy electrolysers at scale which in turn may hinder the development of renewable hydrogen production.

7.2.3 Renewable power supply

Most countries have targets for the deployment of more renewable energy to decarbonise the power sector. The intermittency of renewables means that more capacity is needed to guarantee sufficient generation of power. Thus, for every 1 MW of coal or gas power capacity shut down, 3 MW of renewable capacity will be needed (Ross, 2022). Economic development and the ongoing electrification to decarbonise various sectors such as transport, heating and some industrial processes will increase the demand for electricity. The IEA (2022b) predicts that total electricity generation will increase by 3.2%/y to 2030 and then by 3.4%/y to 2050. In 2020, the global total installed fossil-fuelled capacity was 4415 GW and there was 2765 GW of renewable power generating capacity (Statista, 2022b). In 2021 solar and wind power generation reached 10% of global electricity production (28,466 TWh) for the first time (Ember 2022; Statista 2022c). Fossil fuel dominates electricity production, accounting for 62% of global power generation (2021). To achieve NZE power by replacing fossil-fuelled generation with renewables, the installed renewable capacity would need to increase by 480% to over 16,000 GW to meet today's electricity demand. It is a massive challenge to meet the renewable power targets for direct electricity consumption.

Electrolysis is energy intensive so large-scale production of renewable hydrogen will require huge amounts of renewable power to drive the process. In Europe for example, the EU's 40 GW electrolyser capacity target (producing 10 MtH_2/y) by 2030 would require 477 TWh of additional renewable power generation which is over half of the total EU renewable generation in 2019 (Burgess, 2021b). Achieving this target would require a higher ramp-up of renewable electricity generation for hydrogen to 2030 than that of the entire power sector in the 2010-2020 period (around 380 TWh). On a global scale, to meet the Hydrogen Council's projected demand of 530 MtH_2 in 2050, 29,000 TWh of electricity would be required. This is more than the total global generation of electricity by all sources in 2018 (Zapantis, 2021). This highlights the enormous challenge to expand renewable power capacity to meet direct electricity demand while also supporting the production of renewable hydrogen.

In addition, the nature of the targeted end-use sectors means that much of the hydrogen will need to be converted to ammonia, leading to large conversion losses, resulting in less energy available at the end, or the need for higher input volumes. The EU has emphasised its requirements that the generation of renewable hydrogen must come from 'additional' renewable power or curtailed existing capacity, with scope for possibly using repowered renewable facilities. According to Platts Analytics (Burgess, 2021), the potential surplus wind and solar for grid-connected electrolysers in major European markets will be less than 6 TWh/y by 2030 (and 477 TWh/y is needed). The question is if and how the 10 Mt/y renewable hydrogen production target can be met given the utilisation rate limitations of running electrolysers from renewables, and the vast amounts of power needed to reach the target. Low-emission hydrogen production from coal and gas with CCUS, therefore, is essential to fill the supply and demand gap. Consequently, under the EU proposed emissions trading scheme (ETS) both renewable and fossil fuel-based low-emission hydrogen production will be eligible for free allowances.

It is unlikely that large consumers of hydrogen in emerging and developing economies, such as China and India which currently rely on coal to generate more than half of their electricity, can build out renewable generation capacity quickly enough to meet the massive electricity demand in the near to long term. It is unrealistic to expect the projected rapid increase in demand for low-emission hydrogen to be met by renewable hydrogen production in these countries due to the competition for renewable power generation from direct electricity use. It is expected that part of the low-emission hydrogen demand will have to be met by hydrogen from fossil fuels, including coal with CCUS.

7.3 COST OF HYDROGEN

The cost of low-emission hydrogen is one of the most decisive factors influencing its competitiveness and thus increased use. There have been many studies assessing the costs of hydrogen production using different processes and Kelsall (2021) has summarised the results (*see* Table 13). Generally, the studies show that the cost of low-emission hydrogen production based on coal gasification with CCUS and natural gas SMR or ATR with CCUS are significantly lower than that of renewable electrolytic hydrogen, typically by a factor of around 3. This indicates that with a large existing unabated fleet of gas- and coal-based hydrogen production, there is an urgent need to deploy CCUS at scale to transition to low-emission hydrogen production.

TABLE 13 HYDROGEN PRODUCTION COSTS (KELSALL, 2021)

Reference	Costs of hydrogen, \$/kgH_2		
	Hydrogen from renewable electricity	Natural gas SMR/ATR with CCUS	Coal gasification with CCUS
CSIRO (Bruce and others, 2018)	7.7	1.7–2.1 (85% capacity factor)	1.9–2.4 (85% capacity factor)
IEA, 2019	2–4 (renewable electricity cost of 40 \$/MWh, 4000 h/y operation, best location)	1.5–2.4	1.5–2.0
IRENA, 2019	2.7–6.8 (lower cost is wind at 48% capacity factor. Higher cost is solar PV at 26% capacity factor)	1.6–2.3	2.0
Hydrogen Council, 2020	6.0	1–2	2.1
USDOE, 2020	6.0–9.3	1.5–2.3	1.6
Average	5.6 with range of 2.0–8.3	1.8	1.9 with range of 1.6–2.4

The costs of hydrogen vary significantly depending on the production method used and are sensitive to fuel and electricity prices. There are also large regional variations. Other factors influencing the cost of hydrogen include plant size, capacity factors, carbon price, and learning rates for CCUS and electrolysis systems. Thus, direct comparisons of the costs from different studies are difficult to make as the estimates are made based on different assumptions. However, these study results demonstrate a general trend that fossil fuel-based low-emission hydrogen costs less than renewable hydrogen.

The USDOE (2020) compiled the costs of hydrogen production by technology (*see* Figure 24). It shows that the cost of low-emission hydrogen from coal gasification and natural gas reforming with CCUS ranges from 1.63–2.27 \$/kgH_2, compared to 6–9.3 \$/kgH_2 for renewable hydrogen. The estimated costs for renewable hydrogen produced with electrolysers are wide-ranging. This is because different assumptions are made for utilisation of the electrolyser (capacity factor), the price of electricity and capital expenditure (Capex) of the electrolyser stack which is responsible for 50% and 60% of the Capex costs of alkaline and PEM electrolysers, respectively (IEA, 2019). Scaled-up electrolysers and automated production processes can significantly reduce Capex. Increasing the capacity factor (the ratio of operating hours at full load to the maximum hours over a given period, normally a year) of electrolysers will also reduce the cost of hydrogen.

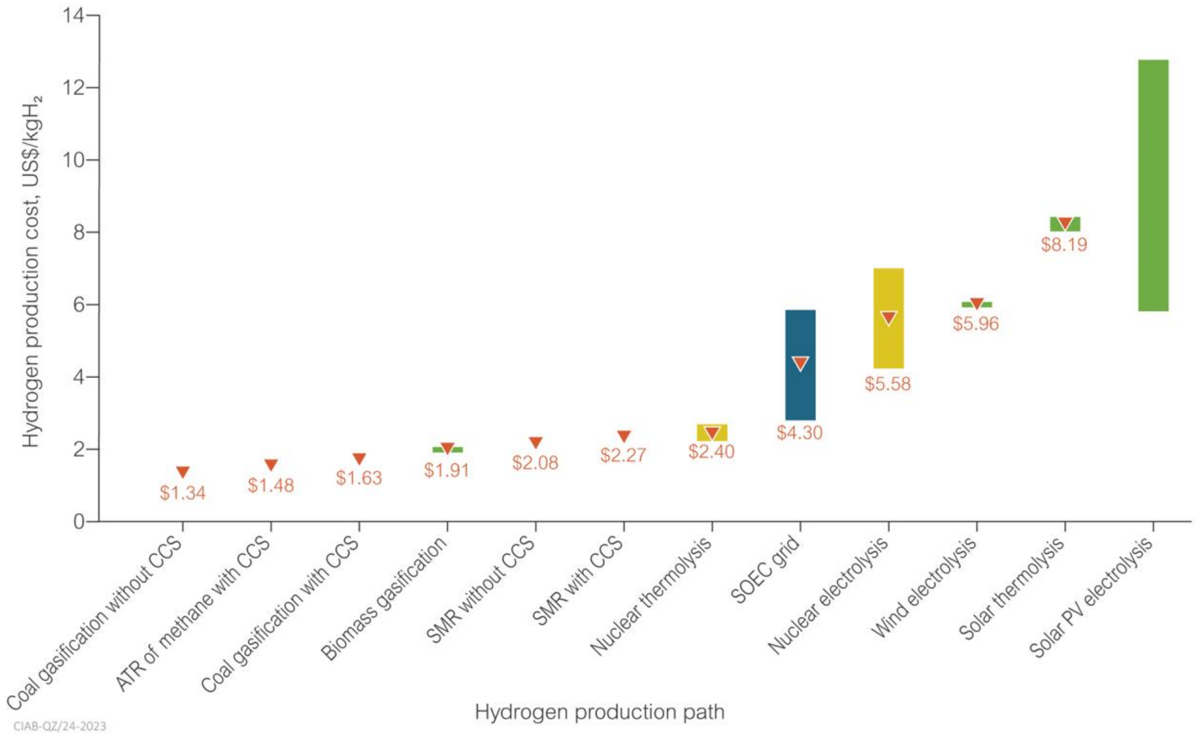

Figure 24 Comparison of hydrogen production costs (USDOE, 2020)

The cost of hydrogen from gas with CCS can vary significantly from place to place due to differences in fuel costs. In locations with low-cost gas, Capex is the largest cost component, while in places with high gas prices, fuel cost is the largest cost component and hence, the cost of hydrogen production is more sensitive to the change in gas prices. Producing hydrogen from coal gasification with CCS is more capital-intensive due to the complexity of the coal gasification-based approach compared with SMR and electrolysis. The cost of coal has a relatively small impact on the cost of hydrogen but will still be reflected in the hydrogen price. Producing hydrogen using high-rank coal which is more expensive will have higher cost than hydrogen from low-rank coal. The cost of transport and storage of CO_2 also has an impact on the total cost of production. Producing 1 kg of hydrogen from coal with CCS will require approximately 17.8–21.6 $kgCO_2$ to be transported and stored (IEA and ACCA21, 2022). The figure for gas is 8.9–9.8 $kgCO_2$. Thus, the cost of hydrogen production from coal with CCS will be more sensitive to CO_2 transport and storage costs than gas.

The studies discussed above were carried out before the 2021-22 energy crisis when natural gas and electricity prices were low, so they do not reflect current (late 2022) energy prices. Commodity experts at Argus (2022d) conduct cost evaluations for hydrogen produced at new and existing facilities via several industrial standard production paths on a weekly basis using the most up-to-date coal, natural gas and electricity prices. The following assumptions are made in the Argus modelling work:

- For renewable hydrogen, two technologies, alkaline and PEM, are modelled for which capital, operating and other costs vary by location. It is assumed that both alkaline and PEM plant have a design capacity of 100 MW, operating and other costs of 3.5%/y of capital expense and a plant lifetime of 25 years. A capacity factor of 70% is assumed for grid-connected and diurnal installations, and 60% for offshore wind-powered projects.

- For low-emission hydrogen produced via natural gas SMR with CCUS, the capital, operating and other costs vary by location with natural gas drawn from the local market, priced at regulated tariffs or bought at international market prices. It is assumed that all SMR plants (new and retrofit) have a design capacity of 60,000 t/y and a capacity factor of 90%.
- For the cost of low-emission hydrogen produced using coal gasification with CCUS, it is assumed that all plants (new and retrofit) have a design capacity of 250,000 t/y and a capacity factor of 90%. Capital, operating and other costs vary by location with coal purchased at international market prices. The quality of coal (in terms of kcal/kg coal) produced in different regions is included in the cost evaluations.
- For fossil fuel-based hydrogen production with CCUS, CO_2 transport and storage are assumed to cost 20 $/t. Hydrogen producers are assumed to purchase allowances or pay CO_2 taxes for residue CO_2 emissions.

The costs of hydrogen published by Argus on 8 November 2022 are shown in Table 14. It should be noted that the assumed 100 MW plant capacity and 70% capacity factor for the diurnal PEM plant (PEM facility with dedicated solar and/or wind power plants) are much higher than those of existing installations. Today, the largest PEM electrolysis plant in operation has a capacity of 20 MW. The capacity factor of diurnal electrolysis plants located where there are excellent solar and wind resources such as the AREH project under development in Western Australia is estimated to be 48% (Zapantis, 2021), way below the 70% used by Argus. As a result, the estimated cost of renewable hydrogen from the diurnal PEM plant by Argus can be significantly lower than the actual costs of the existing diurnal PEM plant. Also, the results from other studies shown in Figure 24 indicate that hydrogen from more expensive SOEC electrolysers powered by grid electricity has significantly lower costs than electrolytic hydrogen powered by solar or wind energy. In contrast, Argus data show that the costs of hydrogen from grid-powered alkaline and PEM electrolysers on the east coast of the USA are more than twice that of hydrogen from diurnal PEM plants. It is likely that the costs of low-emission hydrogen from coal and gas shown in Table 14 represent the current production costs, whilst the costs of renewable hydrogen from diurnal PEM plants are more representative of the future costs of hydrogen from such installations but are lower than current actual costs.

TABLE 14 COST OF HYDROGEN BY TECHNOLOGY AND BY REGION, $/kgH$_2$ (ARGUS, 2022D)

Country/region	Coal gasification with CCUS			
	Includes Capex		Excludes Capex	
Australia	Coal of 5500 kcal/kg	Coal of 6000 kcal/kg	Coal of 5500 kcal/kg	Coal of 6000 kcal/kg
	3.36	5.60	2.61	4.85
China	Coal of 3800 kcal/kg	Coal of 5500 kcal/kg	Coal of 3800 kcal/kg	Coal of 5500 kcal/kg
	3.86	3.94	3.09	3.17
Indonesia	Coal of 3800 kcal/kg	Coal of 5500 kcal/kg	Coal of 3800 kcal/kg	Coal of 5500 kcal/kg
	3.34	3.77	2.50	2.94
South Africa	Coal of 4800 kcal/kg	Coal of 6000 kcal/kg	Coal of 4800 kcal/kg	Coal of 6000 kcal/kg
	3.52	4.08	2.52	3.07
USA East Coast	4.19		3.45	
	Natural gas reforming with CCUS			
	Includes Capex		**Excludes Capex**	
	SMR (new)	**SMR (retrofit)**	**SMR (new)**	**SMR (retrofit)**
Australia	3.62	n/a	3.10	3.08
Canada	1.17	n/a	0.65	0.69
Middle East average	4.65	n/a	4.13	na
Northeast Asia average	5.82	n/a	5.29	n.a.
Northwest Europe average	3.67	n/a	3.15	n.a.
US Gulf Coast	1.73	n/a	1.22	1.19
North America average	1.45	n/a	0.94	na
	Renewable powered electrolysis			
	Includes Capex		**Excludes Capex**	
Australia	Diurnal+PEM		Diurnal+PEM	
	5.03		3.18	
Canada	offshore wind+PEM		Offshore wind+PEM	
	6.43		4.51	
China	Diurnal+PEM		Diurnal+PEM	
	4.73		2.85	
Middle East average	Renewables+PEM		Renewables+PEM	
	5.55		3.69	
Northwest Europe average	Renewables+PEM		Renewables+PEM	
	7.31		5.32	
South Africa	Diurnal+PEM		Diurnal+PEM	
	5.90		3.73	

	Includes Capex			Excludes Capex		
US West Coast	Grid+alkaline[†]	Grid+PEM[†]	Diurnal+PEM	Grid+alkaline[†]	Grid+PEM[†]	Diurnal+PEM
	10.86	11.32	5.12	9.71	9.49	3.29

* not available

† depending on the local energy mix, the grid electricity contains fractions of fossil-fuelled electricity generation so the hydrogen produced using grid electricity is not carbon-free. These data are included in the table for comparison purposes

Table 14 shows that there are huge regional variations in the production costs of hydrogen. Even with the lower estimated values, the costs of renewable hydrogen are generally higher than low-emission hydrogen from coal or gas with CCUS. In Europe, renewable hydrogen costs twice as much as low-emission hydrogen from gas SMR with CCUS. Canada and USA can produce hydrogen from gas with CCUS at very low costs due to the low gas prices in internal markets. In comparison, the costs of renewable hydrogen are substantially higher, by a factor of 5.5 for Canada and 3 for the USA. In the Middle East, Argus data show that the average cost of hydrogen from gas SMR with CCUS is higher than in Europe. This is in contrast to the common belief that the Middle Eastern countries, as major gas and oil exporters, with much lower gas prices in internal markets than in Europe, would have low-cost production of hydrogen from SMR and CCUS. However, even with this high cost, low-emission hydrogen from gas is still 20% cheaper than renewable hydrogen.

For hydrogen from coal gasification with CCUS, the production costs of hydrogen using high-rank coal are slightly more than those from low-rank coal, rising 2–16% in China, Indonesia and South Africa. The cost of renewable hydrogen would be 45–68% higher than low-emission hydrogen from coal in South Africa and 20–22.5% higher in China. The China Hydrogen Alliance Research Institute, however, claims that the cost of coal accounts for almost 50% of the production cost of hydrogen in China (*see* Table 15). Depending on the coal rank, the cost of hydrogen from coal with CCUS ranges from 2.32–3.34 $/kgH$_2$, compared to 3.05–4.06 $/kgH$_2$ for hydrogen from gas SMR with CCUS (Sheng, 2022). Due to the low price of electricity in China, the cost of hydrogen production using electrolysers is relatively low. On average, the cost of hydrogen production is higher, by 54% from alkaline and 87% from PEM electrolysers, compared to hydrogen from coal gasification with CCUS.

TABLE 15 COST OF HYDROGEN PRODUCTION BY TECHNOLOGY IN CHINA (SHENG, 2022)

Technology	Coal gasification		Natural gas SMR		Electrolysis	
	Unabated	With CCUS	Unabated	With CCUS	Alkaline	PEM
Cost*, $/kgH$_2$	1.16–2.32	2.32–3.34	2.18–3.34	3.05–4.06	2.9–5.8	4.06–6.53

* the average exchange rate of Chinese yuan (CNY) to US dollar during May and November 2022 is used to convert CNY to $

In Australia, Argus data show that the sort of coal used also has a big impact on hydrogen cost. Hydrogen from high-rank coal costs 67% more than that from low-rank coal and is more expensive than hydrogen from gas SMR with CCUS. This is partly because high-rank coals cost much more than low-rank coal such as lignite. The production cost of hydrogen from low-rank coal and gas with CCUS rom Argus are comparable and are 50% cheaper than hydrogen from diurnal electrolysis plants. The Argus estimates are based on coal prices in the international market. However, Australia has low-rank coal (lignite) reserves that are generally not traded and only used locally. The cost of this lignite is based on the costs of its extraction, which tend to be about 10 $/t, whereas hard coal was trading at >250 $/t in February 2023 on the global market. Hence, lignite could provide a cheap source for hydrogen production at a cost much lower than that estimated by Argus. Therefore, low-emission hydrogen from Australian lignite could be more competitive than natural gas-based, low-emission hydrogen from, for example, the Middle East, Canada and the USA, in the international market.

For the coal-dependent countries analysed in this study, producing hydrogen using coal gasification with CCUS has an economic advantage over renewable electrolytic hydrogen production. In addition, due to the optimal assumptions used, the Argus data on the costs of renewable hydrogen production from diurnal PEM plants are lower than the current actual costs. Therefore, the economic advantage of producing hydrogen from coal gasification with CCUS today is greater than shown in the Argus analysis, and this advantage is likely to continue into the near future.

7.4 A ROLE FOR COAL

Building national hydrogen delivery infrastructure represents a significant challenge. It will take time to develop with various combinations of production and delivery technologies. Different types of delivery infrastructure will also be needed for individual regions and markets including urban, regional, interstate or international, as well as seaborne. Therefore, it seems likely that, to reduce the cost, many new projects will be developed in an industrial cluster that has end-users on site or close by with pipelines linking the producer and consumers. This will require the production of low-emission hydrogen from sources available in the region. Such a 'hydrogen valley' concept is being pursued, for example, in the EU, UK and USA. The clean energy transition will also see the development of a new hydrogen export industry, leveraging global collaborations on hydrogen infrastructure to inform investment and mutually beneficial trading opportunities. This approach is being explored, for example, by exporters in Australia, Canada and the Middle East and importers in Germany, Japan and South Korea.

7.4.1 Geopolitics of the energy transition

In some parts of the world, particularly Asia and the largest emerging markets of China and India, coal accounts for more than half of electricity generation as illustrated in Figure 25. The widely varying role of coal in various economies means that, for some, it may offer a cost-effective route to reducing emissions.

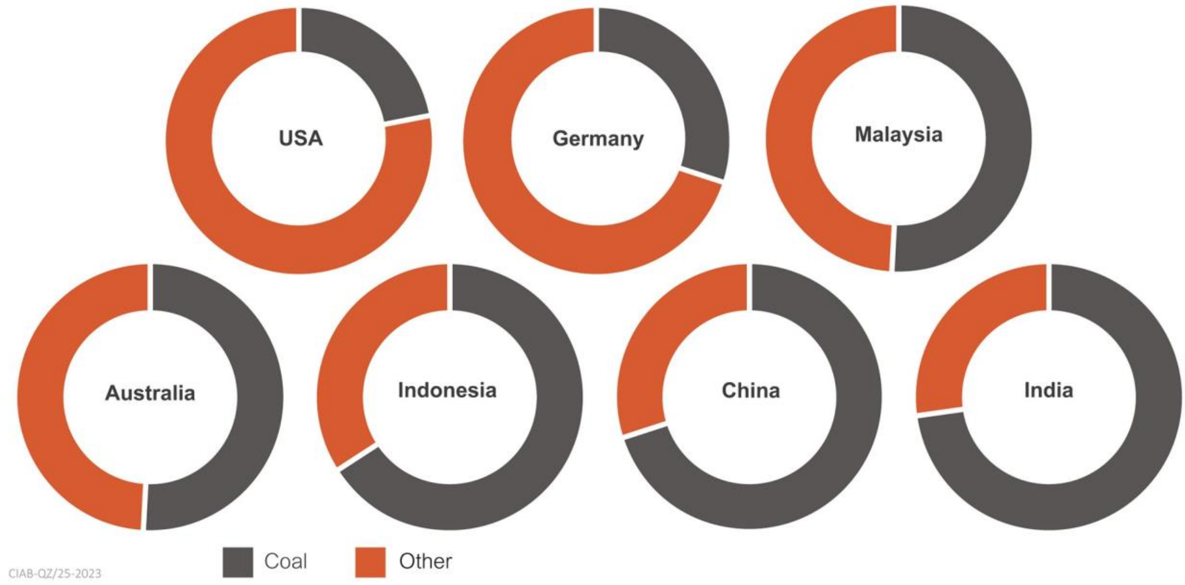

Figure 25 Coal's share of power generation in selected countries (modified from Argus, 2022a)

The EU is committed to phasing out coal despite the recent reprieve for coal-fired power generation in response to Russia's invasion of Ukraine. However, del Pozo and others (2021) suggest that by cogasifying coal and biomass using best available technologies (including CCUS capturing near 100% CO_2) and optimised energy efficiency, negative-emissions hydrogen could be produced in Europe at a competitive levelised cost of 1.5 €/kgH_2 assuming a carbon price of 50 €/tCO_2. Thus, large-scale cogasification of coal biomass with CCUS could enable Europe to meet its demand for low-emission hydrogen with low-cost domestic production from reliable indigenous coal while achieving its ambitious decarbonisation targets.

In North America, the USA has diverse energy resources available including oil, gas and coal, nuclear and renewable energy. It has the technologies and expertise for low-emission hydrogen production and can potentially produce it at low cost. The USA has a large hydrogen industry and leads the production of low-emission hydrogen via SMR and gasification with CCUS. In 2000, the Great Plains Synfuel lignite-gasification facility started operation, generating 1300 t/d hydrogen for syngas production (Zapantis, 2022). A petroleum coke gasification facility is operational producing 200 tH_2/d for fertiliser manufacture and another petcoke/biomass cogasification enterprise, the Wabash Valley Resources Project with a 1.8 MtNH_3/y capacity is planned. Although electricity production from coal has halved in the USA since 2008, there remains an active lobbying presence for its use in hydrogen production. Low-cost low-emission hydrogen production is being pursued to enable large-scale deployment of hydrogen, and coal could provide a diverse and cheap source for its production.

In Asia, many countries, especially China and India, have plentiful, low-cost coal reserves but lack gas and oil resources. Hence, China and India are gas and oil importers, and the price of natural gas is considerably higher than coal. Coal is therefore the main energy source that drives economic development and power generation in the region. Despite the recent significant expansion in renewable hydrogen production capacity in China, and the number of projects under construction, planned or proposed, the development of renewable hydrogen capacity cannot keep up with the rapidly increasing demand, so fossil fuel-based hydrogen production is essential to fill the gap.

Coal gasification is already a major source of hydrogen in China with an output of about 19.6 MtH_2/y. Due to low-cost coal and China's extensive experience of gasification, coal gasification is currently the most cost-effective hydrogen production method in China. Several new coal gasification plants have been built in recent years for the production of chemicals and liquid fuels, and more are planned (Kelsall, 2023). In September 2022, China commissioned the world's largest coal-to-hydrogen plant with a capacity of 0.35 MtH_2/y, for ethylene glycol production (Liu, 2022).

While production from these coal gasification plants is generally unabated, China also leads in the development of combining CCUS with coal gasification. Several demonstration projects are operational or under development as listed in Table 16. Both low-emission hydrogen and CCUS technologies have been identified as key priorities in China's guidelines for carbon neutrality. As many of China's existing coal-based hydrogen plants were built recently, equipping them with CCUS is key to reducing emissions and enlarging the country's low-emission hydrogen supply. Given the low availability of indigenous natural gas resources in China and its large coal gasification fleet, coal-to-hydrogen production with CCUS is expected to persist as an important hydrogen generation route for the short to medium term at least. When best available technologies are adopted, hydrogen from coal gasification with CCUS can have a low carbon footprint and hence, be used as a clean fuel to help China achieve its goal of carbon neutrality. This is also the conclusion of a recent joint study conducted by the IEA and Administrative Centre for China's Agenda 21 (ACCA21) (IEA and ACCA21, 2022).

TABLE 16 KEY COAL GASIFICATION PLANT WITH CCUS PROJECTS IN CHINA (MODIFIED FROM GCCSI, 2022)

Name	Scale	Capacity, t/y	Status	Industry	CO_2 storage
Yanchang Integrated CCS Demonstration	Large-scale facility includes	410,000	Under construction	Chemical production	EOR
	a demonstration facility	50,000	Operational		
Sinopec Qilu Petrochemical CCS	Large-scale facility	400,000	Operational	Chemical production	EOR
Sinopec Eastern China CCS	Large-scale facility includes	500,000	Early development	Chemical production	EOR
	a demonstration facility	50,000			
Shenhua Ningxia CTL	Large-scale facility	2,000,000	Early development	Coal-to-liquids	Under evaluation
Shenhua Ordos CCS Demonstration	Demonstration-scale facility	100,000	Complete	Coal-to-liquids	Dedicated geological storage
Sinopec Zhongyuan CCUS Pilot	Demonstration-scale facility	50,000	Operational	Coal-to-liquids	EOR

India imports most if its oil and gas. In response to this dependence on imports, India has developed policies promoting energy self-reliance by increasing the production and use of domestic coal. For example, in 2016 India launched an initiative known as 'The Methanol Economy' (Saraswat and Bansal, 2017). The scheme aimed to increase India's domestic production of liquid fuels and chemicals through the gasification of domestic coal. India set a target of gasifying a cumulative total of 100 Mt of coal by 2030 and intends to build at least five coal gasification plants in the near term. To help drive these developments, the Indian government granted a concession of 20% on coal revenue share for gasification projects and implemented a R&D programme to develop indigenous technology for the gasification of India's high-ash coal. India's biggest coal producer Coal India Limited (CIL) has signed agreements to set up four large-scale coal-to-chemical projects (PIB, 2022b).

As for the energy transition, India has set an ambitious goal to install 175 GW of renewable energy capacity by 2022; by July 2022 161.28 GW had been installed. India launched a NHM in 2021 to develop a global hub for the manufacture of hydrogen production technologies, and a framework to support manufacturing via incentives and facilitation will be developed. The government is also trying to facilitate demand creation in specific areas including fertiliser, steel and petrochemicals. The NHM focuses on renewable hydrogen production and linking India's renewable capacity with the hydrogen economy. The goal is for the use of hydrogen to not only aid India in achieving its emission goals but also to reduce dependency on imported fossil fuels. However, India lacks capacity of installed electrolysers and the necessary infrastructure, and the renewable hydrogen projects announced in

India lag behind the 2030 target. India strives for energy independence, and this means that coal will be a major source for hydrogen generation through coal gasification for chemicals and liquid fuels production. Adopting CCUS will be key for India to achieve a clean energy transition. India is committed to reducing CO_2 emissions by 50% by 2050 and reaching net zero by 2070. The government recently published a Draft 2030 Roadmap for CCUS (MoPNG, nd). The geological storage potential in India, the government initiatives and industrial activities in CCUS are assessed and reviewed for the ICSC by Adams and others (2021).

7.4.2 Cost considerations

The uptake of low-emission hydrogen will depend on government policies, programmes and regulations, the cost of production and delivery, transport and storage technologies, the cost and build of necessary infrastructure, and end-users' willingness to pay. As hydrogen is currently much more expensive than fossil fuels, end-users will seek the cheapest low-emission hydrogen available. Low-emission hydrogen could come from electrolysis (using renewable- or nuclear-generated electricity) or from fossil fuels with CCUS. The relative economics will depend largely on the resources available locally or on the lowest cost imports when local supply cannot meet demand, and if imports are available. The most cost-effective low-emission hydrogen technology and transport method will vary in each region and could change over time as the cost of renewable hydrogen is expected to fall, relative to the cost of low-emission hydrogen from fossil fuels.

As discussed in Section 7.3, producing hydrogen via coal or gas with CCUS is currently the cheapest option and is expected to remain so at least until 2030. Low-emission hydrogen from coal and gas with CCUS could enable an early scaling up of low-emission hydrogen utilisation as they have lower production costs and benefits from existing infrastructure. For countries such as China, India and South Africa, coal provides not only a secure and reliable energy supply but also the cheapest source for low-emission hydrogen production. Therefore, for coal-dependent developing countries, coal-based, low-emission hydrogen production has the economic advantage and is vital to bridge the supply gap until, and if, renewable hydrogen becomes economically competitive, and its production capacity can meet the demand. In China and India, larger facilities are often located in industrial hubs where hydrogen plants and CCUS facilities can benefit from economies of scale in coal-based hydrogen production and in the transport and storage of hydrogen and CO_2, further reducing the total unit cost of production.

For hydrogen importers, finding a reliable and low-cost supply of low-emission hydrogen is important. Due to the added cost of hydrogen transport, storage and distribution, it is even more challenging to minimise the total cost of hydrogen. Coal could prove to be a critical low-cost source competing with low-emission hydrogen from renewable and gas reforming with CCUS in the international hydrogen market and improve the economic viability of the hydrogen industry. As hydrogen transport options and infrastructure needs vary by region and type of market, the final delivered cost will depend not only on the production cost of hydrogen but also on the transport method chosen and the distance. The competitiveness of different types of hydrogen will thus vary in different markets. While hydrogen by natural gas reforming with CCUS from North America might be more competitive than renewable hydrogen from the Middle East for Europe, coal-based low-emission hydrogen from Australia could be competitive with gas-based hydrogen from Canada and the USA for Japan and South Korea. Therefore, it is vital to keep all options available so importers can choose the source of hydrogen supply and transport technology that are most economical for them. In addition, for hydrogen-importing countries, having a secure and reliable supply is as important as the cost. A diverse supply of low-emission renewable, coal- and gas-based hydrogen offers importers options and better reliability.

For coal exporting countries such as Australia and Indonesia, producing low-emission hydrogen and its derivatives such as ammonia from coal can be an alternative product to export as well as providing a supply of low-emission hydrogen with low and stable prices that are generally not affected by gas price volatility. Analysis from Argus (2022d) found that the costs of hydrogen from coal plus CCUS in Indonesia would be unchanged during the current surge in gas prices. Therefore, hydrogen from coal could provide a choice of cost-competitive low-emission fuel in a global market and be a supplement to other options to meet the global demand.

INTERNATIONAL TRADE CASE STUDY: AUSTRALIA-JAPAN HYDROGEN ENERGY SUPPLY CHAIN

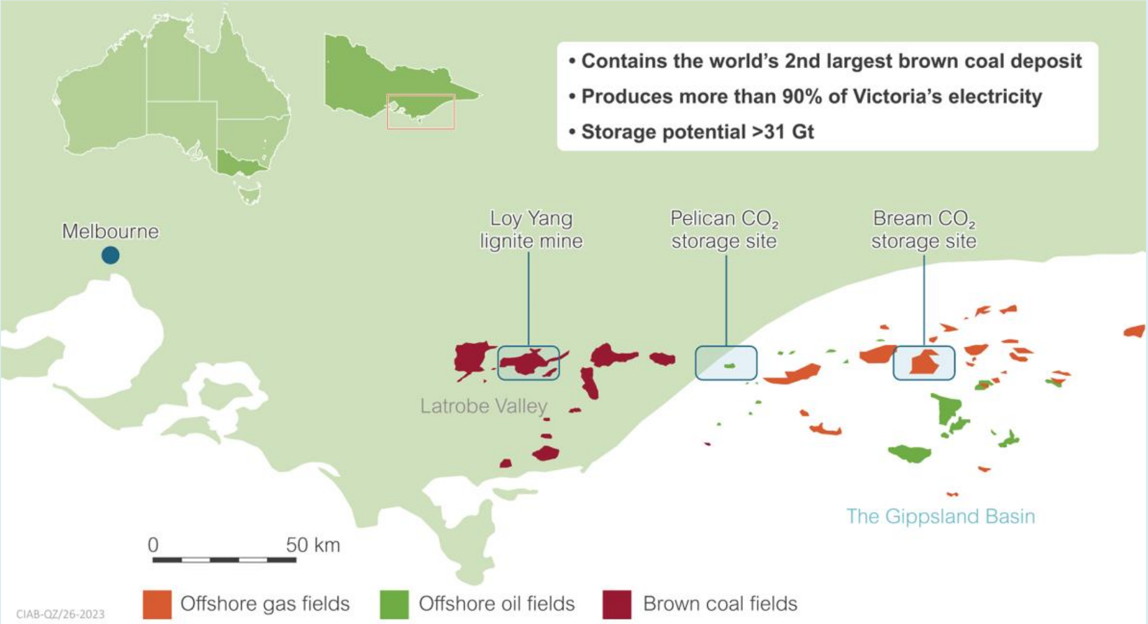

Figure 26 Low-emission hydrogen and ammonia from Victorian lignite (McManus, 2022)

The Hydrogen Energy Supply Chain (HESC) Project, supporting Japan's transition to a 'hydrogen society', envisages low cost, low-emission hydrogen production by gasification of Victorian lignite with CCUS, followed by its liquefaction, then transport to Japan by ship. The HESC Project aims to take advantage of two key resources available in Victoria, Australia. First, the Latrobe Valley contains a potential economic reserve of 33 Gt lignite. The lignite typically contains around 60 wt% of moisture, which means it is not a tradeable commodity and its use is restricted to the vicinity of the mine site. Thus, the price of Victorian lignite is low (~10 AU$/t) and stable and is unaffected by international commodity trading fluctuations. Second, the Latrobe Valley is accessible to at least two high quality CO_2 storage sites beneath the Bass Strait nearby:

1) the Pelican site, located approximately 8 km off the Gippsland coast and 1.5 km beneath the seabed, has a proven CO_2 storage capacity of at least 125 Mt;
2) the depleted Bream oil and gas reservoir, 46 km offshore has a storage potential of over 31 GtCO_2. It is being redeveloped by ESSO Australia for CO_2 storage with capacity of up to 1.5 Mt/y to be available to third party users from 2024 (Kibria and others, 2023).

In addition, the Latrobe Valley is close to a port and the offshore CO_2 storage sites, as shown in Figure 26. Transport of CO_2 by pipeline from the Latrobe Valley to sites in the Bass Strait is one of the lowest-cost options for CO_2 storage in Australia, because of the short transport distance and the high permeability of the storage formation.

The project is being developed in two phases. The pilot phase conducted during 2020-21 successfully produced hydrogen at 99.999% purity by gasification of Victorian lignite and lignite-biomass mixture in the Latrobe Valley. The gaseous hydrogen was transported by road to the Port of Hastings, where it was liquefied and loaded onto the Suiso Frontier, the world's first ocean-going liquid hydrogen carrier ship. The Suiso Frontier arrived at the Port of Kobe on 25 February 2022 and safely unloaded the hydrogen at a purpose-built receiving terminal and storage facility (Kibria and others, 2023).

TABLE 17 COMPARISON OF HYDROGEN PRODUCTION VIA COAL GASIFICATION WITH CCUS AND PEM ELECTROLYSERS IN VICTORIA, AUSTRALIA (LIM AND OTHERS, 2019; KIBRIA AND OTHERS, 2023)

	Gasification with CCUS	PEM with onshore wind farm	PEM with solar PV
Levelised cost of production in 2030, AU$/kg$H_2$	2.74–4.64	5.6–7.9	5.8–8.9
Process water consumption, Mt/y	2.4[a]	2[b]	
Power generation capacity required, MW	240	7000	9400
Footprint, km^2	7.5[c]	2380±1540	230

a: make-up process water; b: purified process water; c: author's own estimate.

In a comprehensive study into the feasibility of producing hydrogen from Victorian lignite for export to Japan, a team of researchers (Lim and others, 2019) conducted technoeconomic analysis of producing 770 t/d hydrogen via gasification of Victorian lignite with CCUS (with a capture rate of 92%) and from dedicated renewable energy farms in Victoria. The lignite gasification plant uses oxygen-blown high-temperature entrained-flow gasifiers followed by a shift reactor and then pressure swing adsorption for hydrogen production with 80% utilisation. Renewable hydrogen is produced using PEM electrolysers (with an 80% utilisation factor) powered by dedicated solar PV or wind farms.

Cost estimates for hydrogen from lignite gasification included the cost of CO_2 capture, transport and storage. Cost estimates for both hydrogen from lignite and renewable hydrogen did not include the cost for transporting hydrogen to the market or end user. The results from this study are compared in Table 17. The economic advantage of producing hydrogen from Australian lignite is clear from the table. In 2030, the cost of hydrogen from lignite gasification with CCUS will still be significantly lower, only half that of renewable hydrogen.

There are various other factors to consider in technoeconomic comparisons of low-emission hydrogen produced either from coal gasification or from electrolysis.

Process water requirements

The study found that the lignite gasification plant needs 2.4 Mt/y make-up process water, higher than the 2 Mt/y required by the PEM electrolyser plant for hydrogen production. The process water is needed as a reagent for the reactions to produce hydrogen so the amount required cannot be reduced. However, electrolysers have a greater demand for high quality water, requiring high purity deionised water, so the raw water needs to be purified. The reverse osmosis purification process is commonly used prior to deionisation to ensure the electrolyser receives water of a sufficiently low electrical conductivity. Depending on the quality of raw water, the water treatment can have a 30–40% rejection rate (Coertzen and others, 2021). At present, a typical water consumption rate for a commercial PEM electrolyser connected to the mains water supply is 17 kgH_2O/kgH_2 (Newborough and Cooley, 2021). Therefore, the actual water consumption is much higher for an electrolysis plant to have a pure process water input of 2 Mt/y. If the raw water quality is low, such as a brine, it may not be a viable source for electrolysis. Feedwater purity requirements of gasifiers vary depending on the gasification technology used but can usually tolerate some feedwater hardness and hence, have lower water treatment rejection rates.

Wet versus dry cooling

As discussed in Section 4.8, apart from process water, the cooling systems of both lignite gasification and electrolysis plant can also use a large amount of water. The estimated total water consumption of gasification and electrolysis plants are similar ranging from 60–90 kgH_2O/kgH_2 for electrolysis and 70 kgH_2O/kgH_2 for gasification plant. In both cases, dry cooling may be an option in arid locations. Although this would reduce the requirement for cooling water, it would have an energy penalty. For electrolysis plants, the cooling load increases significantly over time by 40–70% as the efficiency of the electrolyser stack decreases with increasing operating hours (Coertzen and others, 2021). There are measures to reduce cooling water use, discussed in Section 7.4.3.

Water recycling

Victorian lignite has a high moisture content (~60%), and so needs drying prior to gasification. The water from the drying system can be recovered and used and therefore, reduces the water demand of the gasification plant. A preliminary study suggested that the water inherently present in Victorian lignite might be enough to satisfy all the process requirements without requiring any additional water from the environment (Kibria and others, 2023). Therefore, producing hydrogen from Victorian lignite could have a lower water consumption than renewable hydrogen production.

Electricity requirements

The electrolysis plant consumes substantially more energy, requiring 7000 MW of wind or 9400 MW of solar PV power capacity to drive the process (the larger capacity required is also because of the intermittent nature of wind and solar power) compared with 240 MW capacity for the gasification plant (Lim and others, 2019).

Land requirements

The footprint required for a wind power farm with a capacity of 7 GW in 2030 is estimated to be 2380±1540 km^2. However, the permanent direct impact area that is exclusively disturbed by wind power plant development is around 21 km^2, and most of the area covered by the wind farm can be used for other purposes such as grazing livestock. For a solar PV farm, production of 9.4 GW of electricity will require 150 km^2 of bare panels or 230 km^2 of installed area. In comparison, the lignite gasification plant with CCUS would require approximately 7.5 km^2 of land, including a corridor for the CO_2 pipeline and 3.5 km^2 land for the coal mine (estimated from Google Earth based on one third of the operating footprint of the Yallourn open-cut lignite mine in the Latrobe Valley, Victoria, Australia, which produces three times the coal required by the gasification plant). Therefore, the production of renewable hydrogen will likely be limited by the large areas of land required.

Critical minerals requirements

Some electrolysers require critical minerals and/or rare earth elements for the catalysts. There is growing awareness of the environmental impacts of the production of these materials, including the greenhouse gas emissions. Accurate data are not available for this report.

A well-to-gate analysis (including all upstream GHG emissions) shows that hydrogen from the lignite gasification plant plus CCUS with a capture rate of 92% can meet the EU Taxonomy specification of <3 $kgCO_2/kgH_2$ for sustainable hydrogen (Kibria and others, 2023). The carbon emission intensity can be further reduced to achieve zero or negative emissions by cogasification of lignite with biomass.

In summary, the above assessment suggests that coal gasification with CCUS could provide an innovative, cost-effective and environmentally conscious solution to the safe production of low-emission hydrogen. The lower costs of hydrogen from coal with CCUS make it an economically viable choice and competitor in the international hydrogen market, complementing other options in meeting the global demand for low-emission hydrogen.

7.4.3 Environmental impacts and resource requirements

The key metrics for traded hydrogen markets in the future will be cost and carbon footprint. On the carbon footprint, coal gasification combined with CCUS for hydrogen production can compete with natural gas-based production with CCUS, as explained in Section 4.7 and in the case study 'Australia-Japan Hydrogen Energy Supply chain'. Hydrogen from coal gasification with CCUS can have a low life cycle carbon footprint which is comparable to that of renewable hydrogen if the best available technologies and operational practices are used together with the highest CO_2 capture rates.

The production of low-emission hydrogen using electrolysers or coal or gas with CCS requires many resources such as land, water, electricity, coal, gas and CO_2 storage sites as well as raw materials, critical metals and rare earth elements.

As described in Section 4.8, hydrogen production processes require water as a feedstock for the reaction and for cooling. Production of electrolytic hydrogen and hydrogen from coal plus CCUS are water demanding (*see* Table 8). However, the water quality required by electrolysers is higher than for coal gasification. While some low-quality raw water and/or recycled wastewater can be used in a coal gasification plant after proper treatment, it may not be a viable source for electrolysis. Also, given that renewable solar energy is often available in more arid parts of the world, water shortages are more likely to be an issue for developing renewable hydrogen projects. In May 2022, a plan to develop a 6 GW renewable hydrogen facility in South Australia was cancelled due to a lack of water (Currie, 2022). For locations in coastal areas, desalination of seawater can provide an alternative water supply, but the cost of hydrogen will be higher as desalination is energy intensive and could cost 0.7–2.5 $\$/m^3 H_2O$ (IEA, 2019).

While process water use cannot be decreased, there are several measures to reduce cooling water consumption. Air cooling, for example, can cut the demand for cooling water significantly. However, its applicability is subject to location and local climactic conditions. Air cooling is limited to 40°C or 50°C only, depending on the site conditions, and therefore not all wet cooling can be substituted for air cooling (Coertzen and others, 2021). Again, solar energy is often abundant in arid and hot parts of the world such as the Middle East and southern Spain, where the application of air cooling may be limited and/or less effective. Also, air cooling is more expensive, consumes more energy and may result in a lower efficiency leading to higher costs.

Another option to reduce freshwater requirements is to use wastewater from industrial and/or domestic sources. Hydrogen hubs will typically be located in an industrial valley where there are industrial activities and settlements. Consequently, there may be significant volumes of wastewater produced close to a hydrogen plant. Although it is more expensive to treat wastewater to the desired quality (in particular demineralised water for electrolysers), it would not contribute a large difference in capital for the plant. The water would likely have a relatively low associated supply cost, or the project could be paid to take the water from another industrial site and treat it (Coertzen and others, 2021). In addition, these sources of water would be closer to the plant, reducing pipeline and transmission costs. Historically, many industries and settlements are established around coal mines, where coal-based hydrogen plants can benefit from sharing the existing infrastructure, short distance to coal and water supply, and to the end-users so minimising the logistic costs.

Renewable hydrogen needs sufficient land to host the wind and/or solar PV generation capacity whilst fossil fuel hydrogen with CCS requires coal or gas, land for CO_2 pipelines and injection infrastructure, and suitable geological sites for storage of CO_2. As discussed in Section 4.10 and the above case study, solar and wind power generation are land-use intensive and will require considerably more surface area than coal- or gas-fired power plants. The AREH project under development in Australia is a good example to illustrate the land use intensity of renewable power generation. The AREH project plans to build a renewable hydrogen and renewable ammonia facility with a capacity of 1.6 MtH_2/y or 9 $MtNH_3/y$. The production facility will be integrated with solar and onshore wind power with a generating capacity of 26 GW, producing over 90 TWh/y, which is around one-third of all electricity generated in Australia in 2020. AREH benefits from excellent solar and wind resources that together will achieve an expected capacity factor of approximately 48% (BP Australia, 2022; Zapantis, 2021). The project occupies a site area of 6500 km^2, which is four times the size of Greater London. Compared to this, fossil fuel-based, low-emission hydrogen requires modest amounts of land and electricity. A hydrogen production plant with a capacity the same as the AREH project would require about 14 km^2 of land for SMR with CCS or 17 km^2 for coal gasification with CCS (Zapantis, 2021). Therefore, where low-cost land or excellent renewable resources are not available, but coal and carbon storage sites are, low-emission hydrogen from coal with CCS will be the best option.

Building solar and wind power plants also requires large quantities of materials such as concrete, glass and steel (*see* Table 10). Some electrolysers also need critical materials and/or rare earth elements for the catalysts. Production of these materials needs to increase significantly but they are energy- and carbon-intensive, contributing to significant emissions of greenhouse gases. In 2020, the production of steel and cement, two key materials for solar and wind power plants, and also sectors that are difficult to decarbonise, contributed around 15% of global CO_2 emissions. This will affect the life cycle carbon footprint of renewable hydrogen.

In summary, hydrogen from coal can be as clean as hydrogen from natural gas reforming with CCUS and renewable electrolytic hydrogen and is cost competitive. Renewable hydrogen production is resource intensive requiring large amounts of electricity and water, a huge area of land, vast quantities of materials such as concrete, glass and steel, and critical materials and/or rare earth elements for electrolyser catalysts. Depending on the availability of energy and feedstock resources, suitable land and water resources, proximity to the market and transportation requirements, coal will have a role to play in certain regions and markets to support the development of a hydrogen economy and a clean energy transition toward NZE. Low-emission hydrogen from coal can offer a cost-competitive choice, supplementing other options in meeting the expected demand, not only the domestic demand in major hydrogen-consuming countries such as China and India, but also in the global trade to provide importing countries more options of economically viable low-emission hydrogen.

8 CONCLUSIONS

Since the first Hydrogen Energy Ministerial meeting in Japan in 2018, more attention has been paid to the potential uses of hydrogen in many countries. Over thirty governments have introduced or are formulating hydrogen strategies, and more countries have released, or will do so soon, hydrogen roadmaps for developing a hydrogen economy and related technologies. Hydrogen is gathering momentum around the world and numerous companies are seeking to tap into the business opportunities. Global demand is projected to grow rapidly from 94 MtH_2/y in 2021 to potentially 130 MtH_2/y by 2030 (with 34 Mt being low-emission hydrogen) and more than 500 MtH_2/y in 2050 (IEA, 2022a; 2021a). Meeting the demand for low-emission hydrogen will be a huge challenge requiring the rapid scaling-up of production capacity over a short period of time from less than 1 MtH_2/y (2022) to 32 MtH_2/y in 2030.

Low-emission hydrogen can come from renewable-powered water electrolysis, coal gasification with CCUS and natural gas SMR with CCUS. Although coal gasification-based hydrogen production is the most carbon-intensive, implementing CCUS with coal gasification-based hydrogen production with a capture rate of over 90% could reduce the CO_2 emissions substantially from around 20 $kgCO_2/kgH_2$ to less than 1.5 $kgCO_2/kgH_2$, a level comparable to that of natural gas SMR with CCUS. Coal gasification with a 98% rate of capture has an even lower carbon intensity, below 0.4–0.6 $kgCO_2/kgH_2$. While hydrogen production from renewable-powered electrolysis emits no CO_2, electrolysis is the most energy-intensive method requiring large amounts of electricity. Renewable hydrogen needs sufficient land to host the wind and/or solar PV generation capacity which is land-use intensive. Construction of solar and wind power plants needs large quantities of materials such as concrete, glass and steel. Some electrolysers also use critical materials and/or rare earth elements for catalysts. Production of these materials is energy- and carbon-intensive, contributing to significant emissions of GHG. When best available technologies are adopted, hydrogen production from coal gasification with CCUS can have life cycle environmental impacts similar to, or slightly larger than, renewable hydrogen.

Hydrogen production today is mainly a local business with producers and end-users being geographically close. In order to reach the NZE goal and meet the expected demand, hydrogen will need to become an internationally traded commodity. This requires hydrogen that can be delivered to end users at scale and at competitive costs. Key challenges to hydrogen delivery include reducing costs, improving energy efficiency and building hydrogen transport and storage infrastructure while maintaining hydrogen purity and minimising its leakage. Investment is required to significantly expand existing infrastructure, to build new import and export infrastructure and to develop new technologies such as long-distance shipping of liquid hydrogen.

Currently, the projected renewable hydrogen capacity of many countries falls short of their targets, and the gap between existing hydrogen demand and projected renewable hydrogen production capacity is even greater. Therefore, diverse sources for hydrogen production are required that will be linked to the resources available in a region. There are large regional variations in demand and supply, available resources, costs and overall approach to hydrogen. For countries such as China and India, hydrogen production from coal gasification with CCUS will be vital to meet their increasing domestic demands. Some countries such as Japan, South Korea and some European countries will be major demand centres for low-emission hydrogen but have limited domestic capabilities to produce low-cost and/or low-emission hydrogen. Therefore, they need to import hydrogen to meet their demand. Other countries such as Australia, Canada, Chile, Indonesia, the Middle East, Russia and South Africa will not face such barriers, and can potentially produce low-emission hydrogen at competitive costs but have low domestic demand. This generates the need for a global supply chain and provides opportunities for the international trade of low-emission hydrogen to evolve over time. There are active collaborations between the potential importing and exporting countries to establish an international hydrogen market and supply chain.

Developing renewable hydrogen production also faces other challenges such as the insufficient renewable power generation capacity to support large-scale renewable hydrogen production whilst meeting the direct electricity need, the electrolyser production capacity limitations and supply issues of some key materials for electrolyser manufacture. This means that the global demand for low-emission hydrogen cannot be met by renewable hydrogen production, at least in the short to medium term. Therefore, hydrogen production from coal and gas with CCUS is essential to bridge the gap in meeting the demand.

Low-emission hydrogen is an emerging industry. The cost of low-emission hydrogen (including production, transport and storage) is currently very high, which is the main barrier to its widespread application. Hydrogen production from coal gasification with CCUS has a significantly lower cost than renewable electrolytic hydrogen and this economic advantage will continue to 2030 or beyond. Therefore, hydrogen from coal with CCUS can improve the economic viability of low-emission hydrogen use, enabling its early and wider deployment and facilitating the move towards renewable hydrogen use in the longer term. On the other hand, for coal-dependent, large hydrogen-producing and consuming countries such as China and India, coal provides not only the cheapest source but also a secure and reliable supply for hydrogen production. In regions with abundant coal, access to CO_2 storage and limited renewable energy availability, producing low-emission hydrogen from coal with CCUS will also be a low-cost option.

For coal exporting countries such as Australia, Indonesia and the USA, producing hydrogen and its derivatives such as ammonia from coal can offer a suitable replacement for the current income from exporting fossil fuels. Moreover, these countries can produce low-emission hydrogen from coal at low and stable prices, which can be competitive with renewable and gas-based low-emission hydrogen from other regions such as the Gulf States, Canada and South America, in the international hydrogen market. Hydrogen from coal gasification with CCUS can provide importing countries with the option of low-cost, low-emission hydrogen.

For importing countries, the competitiveness of different types of hydrogen varies depending on the nature of the market, infrastructure options and the associated transport economics. While low-emission gas-based hydrogen from Canada and the USA may be as competitive as renewable hydrogen from the Middle East for the European market, importing coal-based low-emission hydrogen from Australia and Indonesia to the East Asian market such as Japan and South Korea could be more economical than importing low-emission renewable and gas-based hydrogen from, for example, the Middle East and North America. Thus, low-emission hydrogen from coal could be a low-cost solution for certain markets.

Hydrogen is an industry in its infancy, and its evolution may be complex and potentially disruptive. Currently, low-emission hydrogen (in particular renewable hydrogen) cannot compete with incumbent technologies and is still in its early stage of market introduction. National policy framework for developing a hydrogen economy and related hydrogen technologies should consider with a special regional dimension the availability of energy and feedstock resources, suitable land and water resources, proximity to the market and transport requirements, as well as social and environmental impacts. Supportive policies should promote hydrogen development that takes advantage of local available resources and is economically viable. Different approaches are required in different regions and markets to reach the ultimate goal of renewable hydrogen use and NZE. International cooperation is vital to establish a global value chain of low-emission hydrogen that is cost-effective and reliable. In certain regions and markets, coal will have a role to play in supporting the development of a hydrogen economy and a clean energy transition toward NZE. Low-emission hydrogen from coal can offer a cost-competitive choice, supplementing other options in meeting the expected demand, not only the domestic demand in major hydrogen-consuming countries such as China and India but also in the global trade to provide importing countries more options of economically viable low-emission hydrogen.

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