inthe Netherlands, the Zero Carbon Humber project in the United Kingdom, and CarbonNet in Australia.

Growing momentum for CCUS

Interest in CCUS is expanding globally, as strengthened climate commitments – including ambitious net zero targets – from governments and industry drive renewed momentum. In the first eight months of 2021, more than 40 new commercial projects were announced, reflecting an improved investment environment. A variety of CCUS projects are operating or in planning across several sectors:

- **Industry:** CO_2 capture is already an integral part of urea manufacturing and other industrial processes. Deployment is expanding to chemical products, the steel sector (with one commercial plant operating) and the cement sector (construction to retrofit a plant in Norway has commenced).
- **Electricity and heat:** Two coal-fired power plants equipped with CCUS (in Canada and the United States) have a capture capacity of 2.4 Mt CO_2/yr. Globally, plans exist to equip around 30 coal, gas, biomass or hydrogen power facilities with CCUS.
- **Fuel supply:** Most existing commercial CCUS facilities are linked to natural gas processing, which has relatively low capture costs; collectively, they currently capture almost 30 Mt CO_2/yr. A wide range of CCUS projects are planned, associated with production of low-carbon hydrogen and biofuels, refining, and LNG; several are linked to development of regional CCUS and/or hydrogen hubs.
- **Direct air capture:** A number of small pilot and demonstration DAC plants are currently operating around the world, including some in commercial operation to provide CO_2 for beverage carbonation and greenhouses, and a large-scale (1 Mt/yr) facility is in development in the United States.

CCUS technologies and applications are at various stages of development. Several capture technologies, such as chemical absorption of CO_2 during hydrogen production in ammonia plants, are mature and have high (85-90%) average capture rates (e.g. of CO_2 in the gas stream). Boosting capture rates to 99%, which would substantially decrease residual emissions from CCUS operations, is technically possible with minimal additional cost, but requires incentives such as sufficiently high CO_2 prices or low-carbon standards.

As urea applied on soils breaks back down into ammonia and CO_2 and synthetic fuels are combusted to extract embedded energy, it must be noted that CO_2 used for urea production or for synthetic fuels will eventually be released into the atmosphere. For hydrogen to be considered low-carbon, CO_2 captured during production would need to be permanently stored (rather than used).

A well-selected and well-managed geological storage site can retain stored CO_2 for more than 1 000 years, with minimal risk of leakage. Theoretically, global CO_2 storage resources are vast; however, some reservoirs will not be suitable or accessible. In many regions, detailed site characterisation is still needed to assess the feasibility and scope of permanent CO_2 storage. At present, a relatively low share of captured CO_2 – only 20% the 40 Mt quoted above – is directed into permanent geological storage (80% is used for EOR).

Hydrogen-based fuels

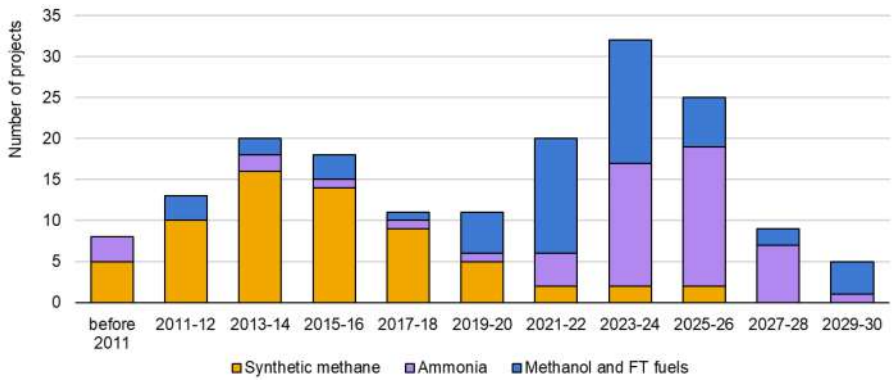
Hydrogen-based fuels are often compatible with existing infrastructure, but cost more

Hydrogen produced through the methods described above has a low volumetric energy density, which makes it more challenging to store and transport than fossil fuels. It can, however, be converted into hydrogen-based fuels and feedstocks (e.g. synthetic methane, synthetic liquid fuels and ammonia) that can be transported, stored and distributed through existing infrastructure for fossil fuels. In fact, some synthetic hydrocarbons from hydrogen can directly substitute for fossil equivalents. The potential benefits and opportunities of these fuels and feedstocks must be weighed against additional conversion losses and related costs.

In 2020, 81 pilot or demonstration projects were in operation, converting electrolytic hydrogen into synthetic methane (59), synthetic methanol (7), synthetic diesel or kerosene (7) and ammonia (8).. Geographically, most are in Europe, and most are at a relatively small scale to demonstrate technologies and supply chains.

Besides hydrogen, synthetic hydrocarbon fuel production requires CO_2 as an input. Initially, the CO_2 may be sourced from hard-to-abate emissions sources. But to ensure the CO_2 neutrality of the produced fuel in the long term, CO_2 supplies should be captured at bioenergy conversion plants or directly from the atmosphere. The Power2Met project (Denmark) uses CO_2 from biogas upgrading, while the Troia plant (Italy) uses DAC for CO_2 to produce synthetic methane.

New projects to produce hydrogen-based fuels from electrolytic hydrogen, by start year



Notes: FT = Fischer-Tropsch. Figure includes eight synthetic methane and five FT fuel projects decommissioned before 2020. Ammonia includes projects in the chemical industry, where ammonia is used as a feedstock.
Source: IEA (2021), Hydrogen Projects Database.

Several projects planned for upcoming years are expected to advance to the commercial scale. With an electrolyser capacity of 2 GW, the Haru Oni project for methanol (Chile) has a planned final production capacity of 550 million litres per year (by 2026). The Helios Green Fuels project (Saudi Arabia), based on electrolyser capacity of 1.5-2.0 GW, has a planned annual production capacity of 235 kt hydrogen and 1.2 Mt ammonia.

In parallel, the focus of projects under construction or planned shifts from synthetic methane to synthetic liquid fuels (ammonia, methanol and Fischer-Tropsch fuels), with the last accounting for >90% of future projects. This may reflect that using hydrogen-based liquid fuels is an important pathway to decarbonise long-distance transport, particularly aviation and shipping. In the Net zero Emissions Scenario in 2050, ammonia covers 45% of global shipping fuel demand while synthetic kerosene accounts for one-third of global aviation fuel consumption.

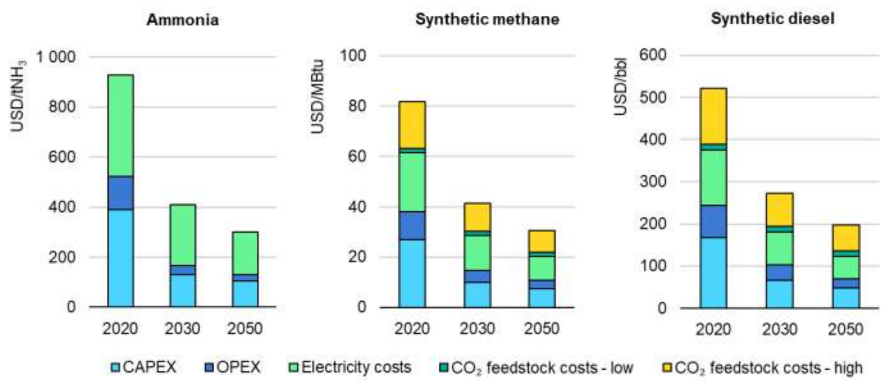
The economics of producing clean ammonia and synthetic hydrocarbon fuels depend on various factors, the cost of hydrogen being key. Fossil fuel and CO_2 storage prices will affect the cost of producing hydrogen using CCUS, whereas for the electrolytic hydrogen route, the availability of low-cost and low-carbon electricity is critical.

In the case of synthetic hydrocarbon fuels, the availability and cost of CO_2 feedstocks is another important factor. CO_2 costs currently range from USD 30/t CO_2 from ethanol plants to USD 150-450/t CO_2 from DAC (but as DAC technology is at an early stage of development, costs could fall to USD 70-240/t CO_2 by 2050). With CO_2 feedstock costs at USD 30-150/t CO_2, production costs for synthetic liquid fuels fall in the range of USD 15-75/bbl.

Current production costs for synthetic liquid hydrocarbon fuels from electrolytic hydrogen are in the range of USD 300-700/bbl. With cost declines for renewable electricity, electrolysers and DAC, they fall to USD 120-330/bbl by 2050 in the Net zero Emissions Scenario, which is still much more expensive than conventional fossil liquid fuels. The situation for synthetic methane is similar.

To support use of these fuels in parts of the energy system with limited low-carbon options (e.g. long-distance transport in aviation or shipping), policy measures are needed to close the cost gap by either pushing up the cost of using of fossil fuels (e.g. CO_2 prices) or incentivising low-carbon fuel use (e.g. clean fuel standards). To close the cost gap with fossil kerosene at USD 25/bbl, a CO_2 price of USD 230-750/t CO_2 would be needed to deliver synthetic liquid hydrocarbon fuels at USD 120-330/bbl.

Levelised cost of ammonia, synthetic methane and synthetic liquid fuels for electricity-based pathways in the Net zero Emissions Scenario, 2020, 2030 and 2050



Sources: Based on data from the Hydrogen Council; IRENA (2020); Agora (2018); Danish Energy Agency (2021); IFA (2021).

Emerging technologies

Hydrogen production technologies of the future hold promise

Solid oxide electrolyser cells (SOECs)

SOECs use steam instead of water for hydrogen production, a key departure from alkaline and PEM electrolysers. Additionally, as they use ceramics as the electrolyte, SOECs have low material costs. While they operate at high temperatures and with high electrical efficiencies of 79-84% (LHV), they require a heat source to produce steam. Therefore, if SOEC hydrogen were used to produce synthetic hydrocarbons (power-to-liquid [PtL] and power-to-gas [PtG]), it would be possible to recover waste heat from these synthesis processes (e.g. Fischer-Tropsch synthesis, methanation) to produce steam for further SOEC electrolysis. Nuclear power, solar thermal and geothermal heat systems, as well as industrial waste heat, could also be heat sources for SOECs.

SOEC electrolysers can also be operated in reverse mode as fuel cells to convert hydrogen back into electricity, another feature that is distinct from alkaline and PEM electrolysers. Combined with hydrogen storage facilities, they could provide balancing services to the power grid, increasing the overall utilisation rate of equipment. SOEC electrolysers can also be used for co-electrolysis of steam and CO_2, thereby creating a syngas mixture (carbon monoxide and hydrogen) for subsequent conversion into a synthetic fuel.

SOECs are still in the demonstration phase for large-scale applications (TRL 6-7[31]). Operational systems, often linked to the production of synthetic hydrocarbon fuels, currently have capacities of <1 MW. The largest system in operation (720 kW capacity) uses renewable electricity and waste heat to produce hydrogen for a DRI steel plant. However, a 2.6-MW SOEC system is being developed in Rotterdam, and several companies (e.g. Bloom, Sunfire) are manufacturing SOEC systems, mainly in Europe. Denmark plans to launch a manufacturing plant with an annual capacity of 500 MW by 2023.

Methane pyrolysis

Methane pyrolysis (also known as methane splitting, cracking or decomposition) is the process of converting methane into gaseous hydrogen and solid carbon (e.g. carbon black, graphite), without creating any direct CO_2 emissions. The reaction requires relatively high temperatures (>800°C), which can be achieved through conventional means (e.g. electrical heaters) or using plasma. Per unit

[31] A technology's technology readiness level indicates its current maturity within a defined scale, ranging from the definition of basic principles (TRL 1) to full commercial operation in a relative environment (TRL 9). See https://www.iea.org/articles/etp-clean-energy-technology-guide.

of hydrogen produced, methane pyrolysis uses three to five times less electricity than electrolysis; however, it requires more natural gas than steam methane reforming.

The overall energy conversion efficiency of methane and electricity combined into hydrogen is 40-45%. Notably, the process could create additional revenue streams from the sale of carbon black for use in rubber, tyres, printers and plastics, though the market potential is likely limited, with global demand for carbon in 2020 being 16 Mt of carbon black, which corresponds to hydrogen production from pyrolysis of 5 Mt H_2. Carbon from pyrolysis could be used in other applications such as construction materials or to replace coke in steelmaking.

Several methane pyrolysis technology designs under development show TRLs of 3 to 6. Monolith Materials (in the United States) uses thermal plasma to create the high temperatures required. After operating a pilot plant for four years, the company launched an industrial plant in 2020 (in Nebraska) and is planning a commercial-scale plant for ammonia production. To convert biogas into hydrogen and graphite, Hazer Group (Australia) is building a demonstration plant for its catalytic-assisted fluidised bed reactor technology, and BASF (Germany) is developing an electrically heated moving-bed reactor process. Together with RWE, in 2021 the company announced a project to use electricity from offshore wind to produce hydrogen from electrolysis and for a methane pyrolysis plant. Gazprom (Russia) is developing a plasma-based process for methane pyrolysis. The start-up C-Zero (United States) is working on an electrically heated molten-metal reactor for methane pyrolysis.

Anion exchange membranes (AEMs)

AEM electrolysis combines some of the benefits of alkaline and PEM electrolysis. Using a transition metal catalyst (CeO_2-La_2O), it does not require platinum (unlike PEM electrolysis). A key advantage is that the anion exchange membrane itself serves as solid electrolyte, avoiding the corrosive electrolytes used in AEL. AEM technology is still at an early stage of development (TRL 4-5), but Enapter (Germany) is developing kW-scale AEM electrolyser systems that can be combined to form MW-scale systems.

Electrified steam methane reforming (ESMR)

SMR is a widely used process to produce hydrogen from natural gas, and it can be combined with CCUS to reduce CO_2 emissions. To achieve capture rates of 90% or higher, CO_2 capture needs to be applied to two gas streams: the synthesis gas stream after the steam methane reformer (characterised by relatively high CO_2 concentrations) and a more diluted flue gas stream caused by steam production from natural gas. Because the latter has a lower CO_2 concentration, capture requires more energy.

An alternative to capturing CO_2 from flue gas, which accounts for 40% of CO_2 emissions from natural gas SMR, is to use an alternative heat source to produce the steam. Haldor Topsoe (Denmark) is using low-carbon electricity (hence SMR becomes ESMR) at a level of 8 kWh/kg H_2. The technology has been demonstrated at only the laboratory scale (TRL 4) to date, but a pilot plant is under construction to use biogas as a feedstock in ESMR to produce hydrogen and carbon monoxide, which will then be converted into methanol.

Infrastructure and trade

Infrastructure

Efficient development of hydrogen infrastructure requires analysis at the system level

Large-scale hydrogen deployment will need to be underpinned by an effective and cost-efficient system for storage and transport, strategically designed to connect supply sources to demand centres and thereby establish a deep liquid market. While there is generally consensus on the need to expand the penetration of hydrogen in the energy system to decarbonise certain hard-to-abate sectors, uncertainty remains about how its production, consumption and geographical distribution will evolve.

This uncertainty in turn influences how infrastructure for hydrogen storage and transport is developed. Efficient infrastructure design will depend on several aspects, including demand volumes; the location of infrastructure relative to resources for producing low-carbon hydrogen (renewables and CO_2 storage sites); technologies used for production; and existing natural gas and electricity networks, as well as their future development. In some cases, transporting electricity for decentralised electrolytic hydrogen production may be the most economical choice, but under different circumstances, centralised production relying on hydrogen transport can be preferable.

The final use of hydrogen can also dictate how it is transported. In certain cases, hydrogen could be used locally to produce end products (chemical products, fertiliser or steel) or to produce other fuels (ammonia or synthetic fuels) that could be transported more cost-efficiently. In other cases, pure hydrogen would be the final product (for use in transport or high-temperature heating) and its transport as pure hydrogen (gaseous or liquefied) or using a hydrogen carrier (ammonia or a liquid organic hydrogen carrier [LOHC]) would depend on the total cost of transport (including conversion/reconversion, storage and transport).

Although hydrogen's high versatility makes a wide range of possibilities and solutions available across diverse sectors, inadequate planning could result in the construction of inefficient and costly infrastructure. Thus, integrated analysis at the system level is needed to design efficient infrastructure for producing hydrogen and transporting it to end users.

More pipeline transport is needed to reach hydrogen targets

Hydrogen can be transported either in gaseous form by pipelines and tube trailers or in liquefied form in cryogenic tanks. IEA analysis indicates that pipeline is generally the most cost-efficient option for distances of <1 500-3 000 km, depending on pipeline capacity. For longer distances, alternatives such as transporting liquefied hydrogen, ammonia or LOHCs by ship could be more attractive (see also Hydrogen Trade below).

Transmitting hydrogen by pipeline is a mature technology. The first hydrogen pipeline system was commissioned in the Rhine-Ruhr metropolitan area (Germany) in 1938 and remains operational. Historically, carbon steel or stainless steel have been used for hydrogen-line pipes, as higher grades (>100 ksi) present a higher risk of hydrogen embrittlement. Hydrogen pipelines currently cover more than 5 000 km, with >90% located in Europe and the United States. Most are closed systems owned by large merchant hydrogen producers and are concentrated near industrial consumer centres (such as petroleum refineries and chemical plants).

Similar to natural gas pipeline systems, hydrogen pipelines are capital-intensive projects that have high upfront investment costs. Due to the inflexible and durable nature of these assets, investments become sunk as soon as the pipeline is laid. High initial capital costs and associated investment risks can therefore impede hydrogen pipeline system development significantly, especially when demand is nascent and regulatory frameworks have not been established.

Moreover, because thicker pipeline walls are required at larger diameters, construction costs for new-build hydrogen pipelines are typically higher than for natural gas pipelines. At a similar diameter, the CAPEX of hydrogen-specific steel pipelines is 10-50% higher than for natural gas.

Reaching the targets set in hydrogen strategies will necessitate much faster hydrogen transmission development. IEA analysis shows that by 2030, the total length of hydrogen pipelines globally will need to double to 10 000 km in the Announced Pledges Scenario and quadruple to >20 000 km in the Net zero Emissions Scenario.

Fortunately, existing natural gas infrastructure can act as a catalyst to scale up hydrogen transportation. In the short to medium term, blending hydrogen into natural gas can facilitate the initial development of trade, while repurposing gas pipelines can significantly reduce the cost of establishing national and regional hydrogen networks.

Hydrogen blending can be a transitionary solution

By providing a temporary solution until dedicated hydrogen transport systems are developed, blending hydrogen in gas networks can support initial deployment of low-carbon hydrogen and trigger cost reductions for low-carbon hydrogen production technologies. While several pilot projects have been launched in recent years, blending still faces several technical and regulatory barriers. Parameters related to natural gas quality (composition, calorific value and Wobbe index) – as regulated in different countries – can limit (or completely prevent) injection of hydrogen into gas grids.

The hydrogen purity requirements of certain end users, including industrial clients, can further constrain blending. In addition, resulting changes in the physical characteristics of the gas can affect certain operations, such as metering. To avoid interoperability issues arising from the changing quality of gas, hydrogen blending will require that adjacent gas markets co-operate more closely.

Hydrogen can be injected into gas networks either directly in its pure form or as "premix" with natural gas. Due to its chemical properties, however, it can cause embrittlement of steel pipelines, i.e. reactions between hydrogen and steel can create fissures in pipelines. Depending on the characteristics of the gas transmission system, hydrogen can be blended at rates of 2-10 vol%H_2[32] without substantial retrofitting of the pipeline system. The hydrogen tolerance of polymer-based distribution networks is typically greater, potentially allowing blending of up to 20 vol%H_2 with minimal or possibly no modifications to the grid infrastructure.

The injection of low-carbon hydrogen into gas grids has grown sevenfold since 2013, but volumes remain low. In 2020, ~3.5 kt H_2 were blended, almost all in Europe and mainly in Germany, which accounted for close to 60% of injected volumes. In France, the GRHYD demonstration project is testing injection of up to 20 vol%H_2 into the natural gas distribution grid of Cappelle-la-Grand (near Dunkirk). In Italy, the Snam project demonstrated the feasibility of blending up to 10% hydrogen in its transmission grid, while in the United Kingdom, the HyDeploy demonstration project tested injection of up to 20 vol%H_2 into Keele University's existing natural gas network (the project became fully operational in early 2020).

Interest in blending is growing in other regions as well. In Australia, pipeline network operators are developing demonstration projects allowing 5-10% volH_2 blend injections starting in 2021 or 2022. Australia Gas Infrastructure Group (AGIG) launched the country's

[32] The energy density of hydrogen is about one-third that of natural gas.

first hydrogen blending pilot project (Hyp SA) in May 2021. Under this project, AGIG will blend about 5% green hydrogen into South Australia's gas distribution network, supported by a 1.25-MW electrolyser operating on solar and wind energy.

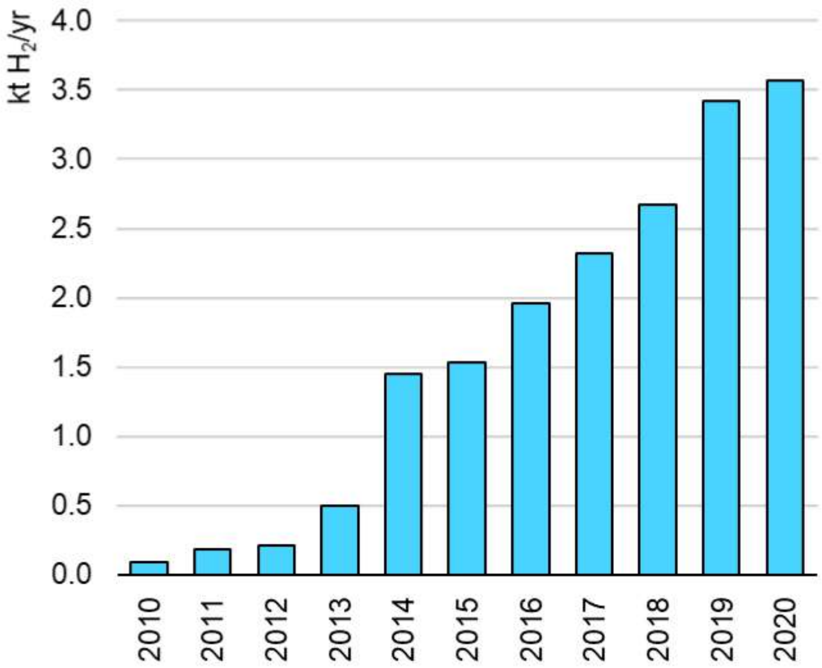
In the United States, a first demonstration project on polymer-based distribution pipelines is expected to be launched in California in 2021, with its initial blend level of 1% volH_2 potentially rising to 20 vol%H_2. In Canada, a hydrogen demonstration project in Ontario is set to start in 2021, allowing for a maximum hydrogen blended content of up to 2% of the natural gas supplied.

Based on projects that have reached final investment decision (FID) or are under construction, hydrogen blending could increase by a factor of 1.3 by 2030 (up >4 kt H_2). However, if all proposed grid-connected hydrogen projects are realised, it could rise by over 700 times to >2 Mt H_2. Still, this falls massively short of the 53 Mt H_2 that need to be blended into gas grids globally in 2030 in the Net zero Emissions Scenario.

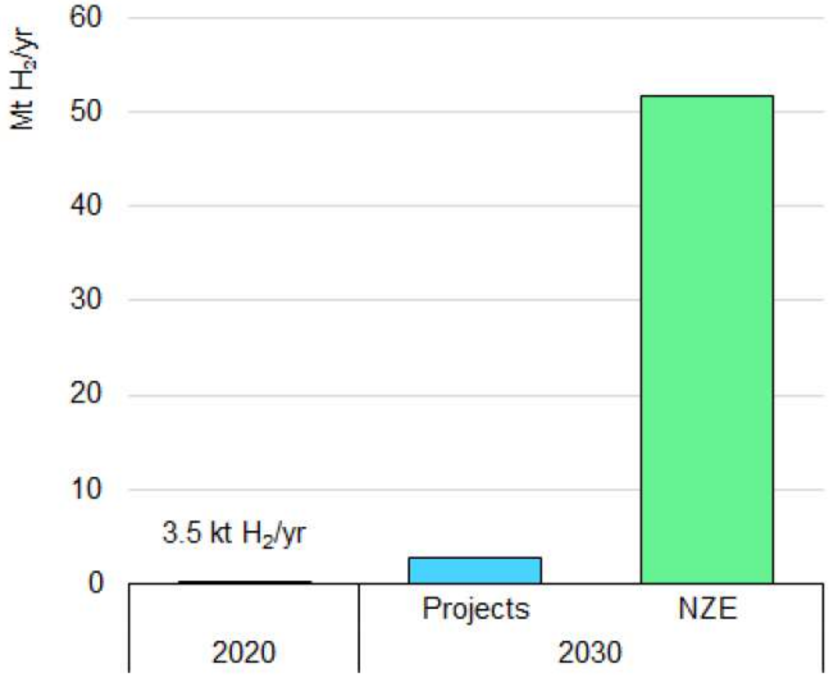
Supportive policies and regulatory mechanisms, including blend certificates and/or guarantees of origin, could spur hydrogen trading and pipeline transport development. While the costs associated with hydrogen blending are relatively low, emissions savings are rather limited, with only a ~10% CO_2 reduction at a blending rate of 30%.

Consequently, in terms of climate change action, blending is a transitionary solution than can help build up stable sources for low-carbon hydrogen demand until a dedicated hydrogen transport system is developed.

Estimated low-carbon hydrogen injected into gas networks, 2010-2020



Low-carbon hydrogen injected into gas networks in the Projects case and Net Zero Emissions Scenario, 2020-2030



Note: NZE = Net zero Emissions Scenario.
Source: IEA (2021), Hydrogen Projects Database.

Old but gold: Repurposing gas infrastructure can catalyse hydrogen network development

Compared with building new hydrogen pipelines, repurposing existing natural gas pipeline systems as dedicated hydrogen networks can be substantially less costly and the lead times can be much shorter. Ultimately, this could translate into lower transport tariffs and improve the cost-competitiveness of hydrogen.

Pipeline repurposing can range from simple measures (e.g. replacing valves, meters and other components) to more complex solutions, including replacing/recoating pipeline segments (which entails pipe excavation). Also, considering that hydrogen has a higher leakage rate and an ignition range about seven times wider than that of methane, it may be necessary to upgrade leak detection and flow control systems.

Based on technical analysis of Germany's gas transmission system, Siemens estimates that compressor stations can generally be used without major changes up to 10 vol%H_2; beyond 40 vol%H_2, they have to be replaced, driving up initial investment costs. Notably, the compressor power required per unit of hydrogen transportation is about three times higher than for natural gas, resulting in higher operating expenses. The amount of total compressor power required will ultimately depend on market demand for hydrogen.

Practical experience of gas-to-hydrogen pipeline conversion is rather limited, with several crude oil and product pipelines repurposed to carry hydrogen in the 1970s and 1990s. The first conversion of a natural gas pipeline for full hydrogen service in the Netherlands was put into commercial service in November 2018 by Gasunie (12 km with throughput capacity of 1.25 kt H_2/yr). Repurposing took six to seven months.

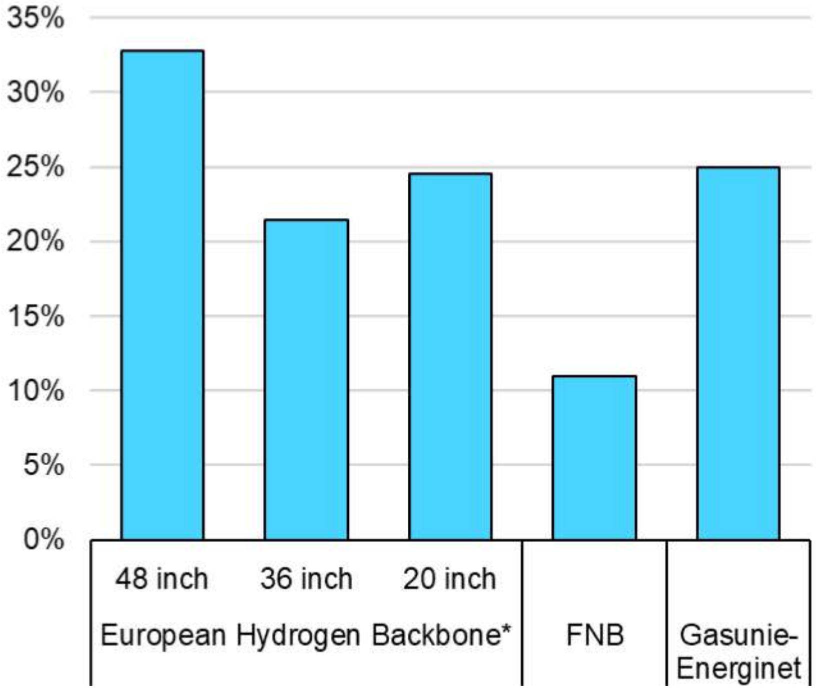
In Germany, as part of its H2HoWi R&D project, E.ON announced the conversion of a natural gas pipeline with an investment cost of EUR 1 million (works started at the end of 2020). In addition, GRTgaz and Creos Deutschland launched the MosaHYc project to convert two existing natural gas pipelines into a 70-km pure hydrogen infrastructure along the border where Germany, France and Luxembourg intersect (FID expected by 2022). In Australia, APA announced the repurposing of 43 km of its Parmelia pipeline in Western Australia as a demonstration project, with testing to be completed by the end of 2022.

The cost benefits of gas pipeline repurposing can be substantial. The European Hydrogen Backbone (EHB) study suggests conversion costs are 21-33% the cost of a new hydrogen pipeline. Of an expected ~40 000 km of hydrogen pipelines in Europe by 2040, the study estimates 75% will be repurposed. The latest draft network development plan of Germany's Transmission System Operator (TSO) Association estimates new-build hydrogen pipeline costs to be almost nine times higher than for gas pipeline conversion.

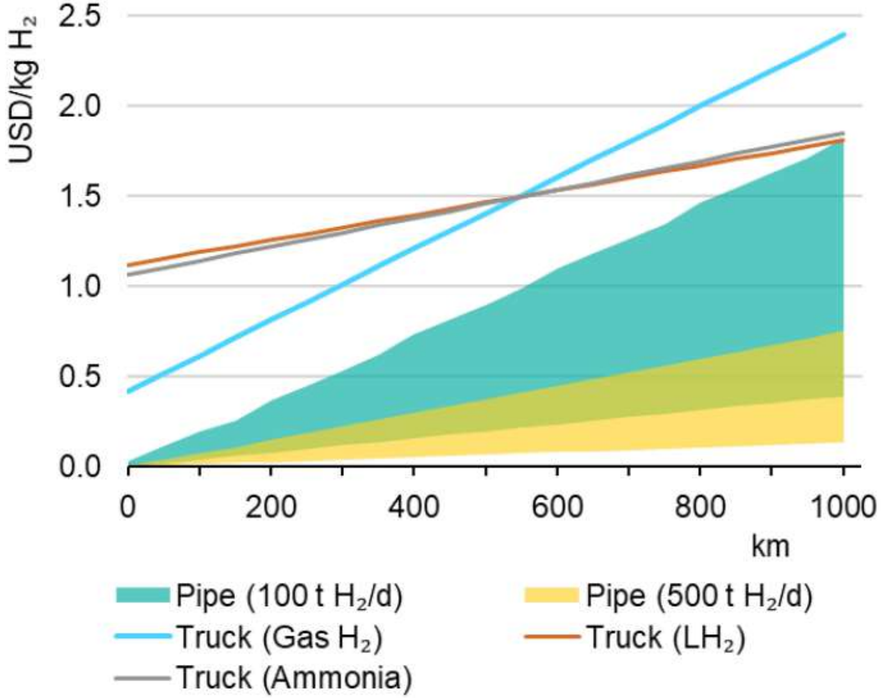
Most recently, the pre-feasibility study for a Danish-German Hydrogen Network estimated repurposing costs to be just 25% of those for new construction. Furthermore, the HyWay27 study, published in the Netherlands (June 2021), estimates that reusing existing natural gas pipelines is four times more cost-effective than laying new hydrogen pipelines. Lower construction costs would translate into more cost-competitive transport tariffs, further supporting deployment of low-carbon hydrogen.

Therefore, of the >1 200 km of hydrogen pipelines foreseen by 2030 in the German TSO Association's Ten-Year Network Development Plan (2020-2030), >90% is repurposed natural gas pipelines. At the end of June 2021, Gasunie announced that the Netherlands' State Secretary for Energy and Climate had requested it to develop a roll-out plan for a national hydrogen transport infrastructure by 2027. Project costs are estimated at EUR 1.5 billion with a throughput capacity of 10 GW, and the hydrogen network would consist of around 85% repurposed natural gas pipes. In September 2021, the Dutch government announced an investment of EUR 750 million (as part of a wider EUR 6.8 billion package on climate measures) to convert parts of the existing gas network into hydrogen transport infrastructure.

Construction cost comparison of repurposing natural gas pipelines vs building new hydrogen pipelines (%)



Estimated transport costs per unit of hydrogen via different types of transport



* Including compressor station CAPEX costs.

Notes: FNB = Vereinigung der Fernleitungsnetzbetreiber (TSO Association of Germany). LH_2 = liquefied hydrogen. In the right graph, the lower limit for pipeline costs corresponds to repurposing existing pipelines, the upper one to building new pipelines. Truck transport costs are based on a capacity of 10 t H_2/d; in the case of liquefied hydrogen and ammonia, they include conversion and reconversion costs.

Sources: Based on FNB (2020), Netzentwicklungsplan 2020; Gas For Climate (2021), European Hydrogen Backbone 2021; Gasunie-Energinet (2021), Pre-feasibility Study for a Danish-German Hydrogen Network.

Underground hydrogen storage in salt caverns and other geological formations

Availability of hydrogen as an energy vector could, like natural gas, enhance overall energy system flexibility by balancing short-term supply variability and meeting seasonal demand swings, thereby improving energy supply security. To fulfil this role, low-carbon hydrogen deployment will need to be coupled with development of cost-effective, large-scale and long-term storage solutions.

Global gas storage totalled >400 bcm in 2020 (10% of total consumption), with porous reservoirs (depleted fields and aquifers) accounting for >90% of storage capacity and the rest located in salt and rock caverns. Assuming global hydrogen demand reaches 530 Mt and a similar storage-to-consumption ratio, hydrogen storage requirements in the Net zero Emissions Scenario could amount to ~50 Mt (~550 bcm) by 2050.

Used by the petrochemical industry since the early 1970s, storing hydrogen underground in salt caverns is a proven technology. Because salt caverns support high injection and withdrawal rates, storing hydrogen there can provide short-term energy system flexibility. Their development, however, depends on geological conditions, i.e. the availability of salt formations. In addition, the injection-withdrawal periodicity of the petrochemical industry's use of underground hydrogen storage may differ from that of other applications, which could require faster cycles.

Four hydrogen salt caverns sites are currently operational. The first was commissioned in in 1972 at Teesside (United Kingdom) by Sabic Petrochemicals, and three are operational in Texas, including Spindletop (commissioned in 2016), the world's largest hydrogen storage facility.

Several pilot projects are under development in Europe: in the Netherlands, testing of hydrogen storage in the borehole of a future cavern in Zuidwending began in August 2021, with the first cavern to be operational in 2026. In Germany, EWE began building a smaller-scale salt cavern storage site at Rüdersdorf at the beginning of 2021, with first test results expected by mid-2022. In Sweden, a rock cavern hydrogen storage facility is under construction, with pilot operations expected to start in 2022. Several pilot projects are also in various stages of development in France and the United Kingdom.

In the United States, the proposed large-scale Advanced Clean Energy Storage (Utah) is targeting start-up in the mid-2020s. While there is no practical experience in repurposing methane caverns for hydrogen service, it is estimated that such an approach would require about the same amount of time as developing a new salt cavern.

While experience storing hydrogen in porous reservoirs such as depleted fields or aquifers is limited, demonstration projects in Austria (the Underground Sun Storage project) and Argentina (HyChico) show it is feasible to store a blend of 10% hydrogen and 90% methane in depleted fields without adversely affecting the reservoirs or equipment. Water aquifers are the least mature of the three geological storage options, and evidence of their suitability is mixed. The feasibility and cost of storing pure hydrogen in depleted reservoirs and aquifers still must be proven, requiring further research.

Another potential barrier is public opposition due to concerns about subsidence and induced seismicity, which should be investigated in depth to minimise risks. In parallel, adequate and transparent communication should address public concerns before large-scale storage site development begins. The IEA Hydrogen TCP is establishing a new task for underground hydrogen storage that will focus on research and innovation to prove its technical, economic and societal viability.

Existing hydrogen storage facilities and planned projects

Name	Country	Project start year	Operator/ developer	Working storage (GWh)	Type	Status
Teeside	United Kingdom	1972	Sabic	27	Salt cavern	Operational
Clemens Dome	United States	1983	Conoco Philips	82	Salt cavern	Operational
Moss Bluff	United States	2007	Praxair	125	Salt cavern	Operational
Spindletop	United States	2016	Air Liquide	278	Salt cavern	Operational
Underground Sun Storage	Austria	2016	RAG	10% H_2 blend	Depleted field	Demo
HyChico	Argentina	2016	HyChico, BRGM	10% H_2 blend	Depleted field	Demo
HyStock	The Netherlands	2021	EnergyStock	-	Salt cavern	Pilot
HYBRIT	Sweden	2022	Vattenfall SSAB, LKAB	-	Rock cavern	Pilot
Rüdersdorf	Germany	2022	EWE	0.2	Salt cavern	Under construction
HyPster	France	2023	Storengy	0.07-1.5	Salt cavern	Engineering study
HyGéo	France	2024	HDF, Teréga	1.5	Salt cavern	Feasibility study
HySecure	United Kingdom	mid-2020s	Storengy, Inovvn	40	Salt cavern	Phase 1 feasibility study
Energiepark Bad Lauchstädt Storage	Germany	-	Uniper, VNG ONTRAS, DBI Terrawatt	150	Salt cavern	Feasibility study
Advanced Clean Energy Storage	United States	mid-2020s	Mitsubishi Power Americas Magnum Development	150	Salt cavern	Proposed

Hydrogen trade