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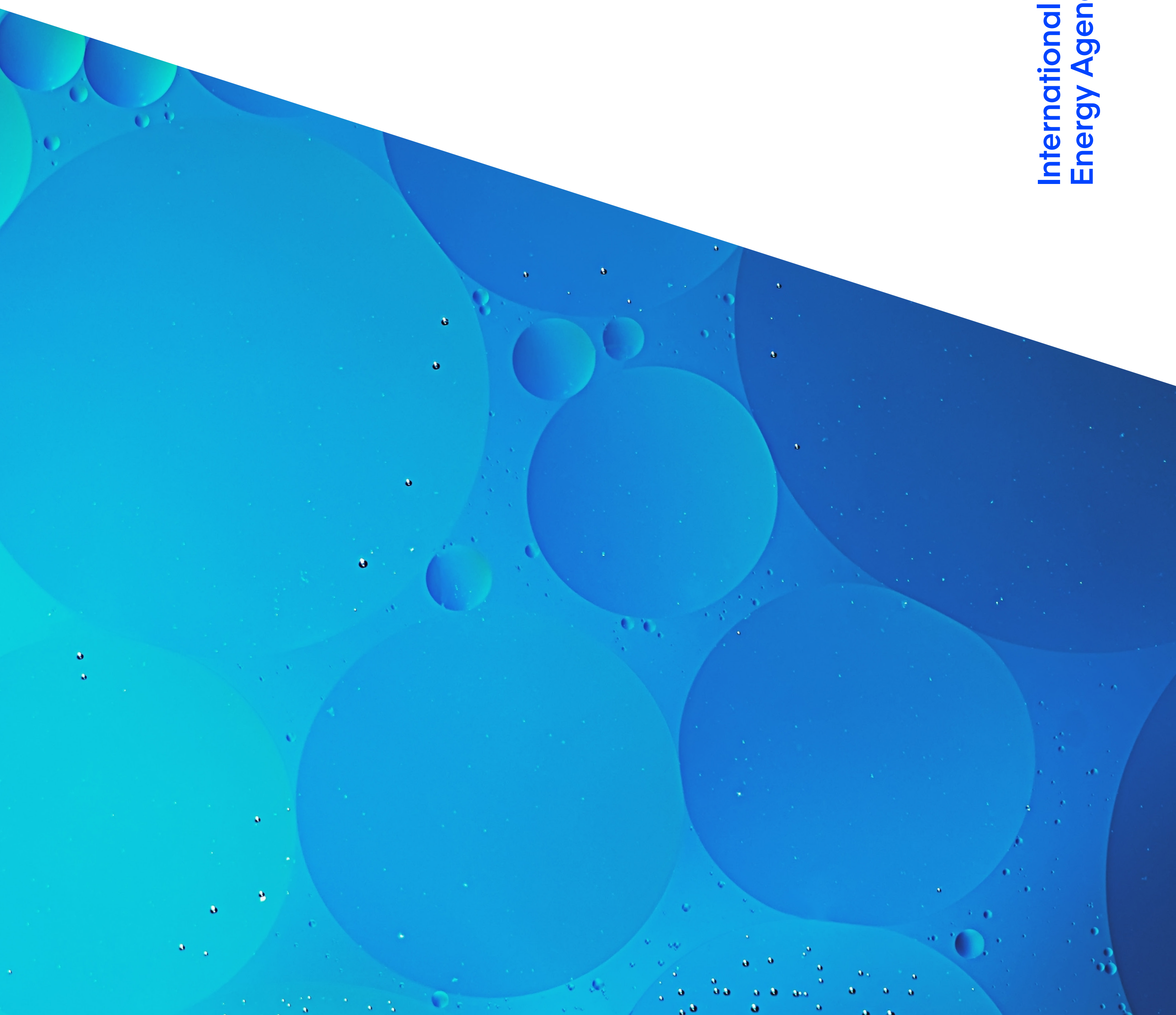
Global Hydrogen Review 2025

International Energy Agency



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Abstract

The Global Hydrogen Review is an annual publication by the International Energy Agency that tracks hydrogen production and demand worldwide, shedding light on the latest developments on policy, infrastructure, trade, investments and innovation.

The report is an output of the Clean Energy Ministerial Hydrogen Initiative and is intended to provide an update to energy sector stakeholders on the status and future prospects of hydrogen, and to inform discussions at the Hydrogen Energy Ministerial Meeting organised by Japan.

The sector has progressed significantly since the first publication of the Global Hydrogen Review in 2021. Low-emissions hydrogen production projects have gone from just a handful of demonstrations to more than 200 committed investments for projects that are increasing in number and in scale, reflecting the importance of hydrogen for climate goals, energy security and industrial competitiveness. Nevertheless, growth has not met all of the expectations raised at the start of the decade and remains uneven. Uncertainties about costs, infrastructure readiness and evolving regulatory frameworks all present barriers to faster deployment.

This fifth edition of the Global Hydrogen Review takes stock of the progress to date and explores the challenges ahead, in order to provide a thorough assessment of the level of hydrogen adoption that could be achieved by 2030. This report includes a special chapter on Southeast Asia, exploring the region's potential for the production and use of low-emissions hydrogen and hydrogen-based fuels and products in the near term.

The report is complemented by updates to the Hydrogen Production and Infrastructure Projects Database, and a new online Hydrogen Tracker that allows users to further explore announced projects for low-emissions hydrogen production and infrastructure deployment, hydrogen production costs by region and technology, and more than 1 000 hydrogen policy measures worldwide announced or implemented since 2020.

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Executive Summary

The hydrogen sector continues to grow despite persistent barriers and project cancellations

Global hydrogen demand increased to almost 100 million tonnes (Mt) in 2024, up 2% from 2023 and in line with overall energy demand growth. This rise was driven by greater use in sectors that have traditionally consumed hydrogen, like oil refining and industry. Demand from new applications accounted for less than 1% of the total and was almost entirely concentrated in biofuels production. The supply of hydrogen continued to be dominated by fossil fuels, using 290 billion cubic metres (bcm) of natural gas and 90 million tonnes of coal equivalent (Mtce) in 2024. Low-emissions hydrogen production grew by 10% in 2024 and is on track to reach 1 Mt in 2025, but it still accounts for less than 1% of global production.

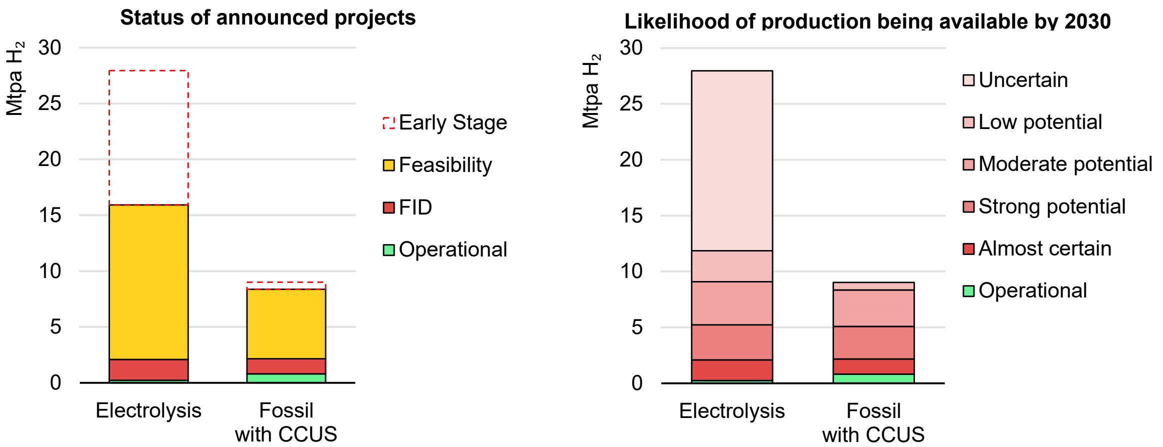
While the uptake of low-emissions hydrogen is not yet meeting the ambitions set in recent years – held back by high costs, uncertain demand and regulatory environments, and slow infrastructure development – there are still notable signs of growth. A recent wave of project delays and cancellations has reduced expectations for the deployment of low-emissions hydrogen this decade. However, in the early stages of adopting new technologies, there are often moments of strong progress as well as periods of sluggish development, and several indicators suggest that the sector continues to mature. For example, although final investments decisions (FIDs) continue to trail well behind announcements, more than 200 low-emissions hydrogen production projects have received them since 2020, when there was only a handful of demonstration projects in operation. Innovation is also moving at an impressive pace, with a record number of technologies across the hydrogen value chain showing significant progress over the past year.

The pipeline of low-emissions production projects has shrunk, but a strong expansion by 2030 is still in sight

For the first time, potential low-emissions hydrogen production by 2030 based on announced projects has declined. Cancellations and delays mean that production that could be achieved based on industry announcements by 2030 stands now at 37 million tonnes per year (Mtpa), compared with 49 Mtpa by 2030 when the *Global Hydrogen Review 2024* was published a year ago. Potential production fell for both projects using electrolysis and those using fossil fuels with carbon capture utilisation and storage (CCUS), although electrolysis projects were responsible for more than 80% of the total drop. These delays and cancellations included early-stage projects across Africa, the Americas, Europe and Australia. At the same time, the number of projects that have received a final investment decision grew by almost 20% since the publication of the *Global Hydrogen Review 2024* and now represent 9% of the total project pipeline to 2030.

Despite the recalibration of industry plans, low-emissions hydrogen production is expected to grow strongly by 2030. Low-emissions hydrogen production from projects that are today operational or have reached FID is set to reach 4.2 Mtpa by 2030, a fivefold increase compared with 2024 production. While this is much lower than government and industry ambitions at the start of this decade, it represents growth from less than 1% of total hydrogen production today to around 4% in 2030. This low-emissions hydrogen growth to 2030 would resemble the fast expansions of other clean energy technologies seen in recent years, such as solar PV. Moreover, a new, comprehensive assessment of the prospects of announced projects for this year's *Review* finds that an additional 6 Mt of low-emissions hydrogen production projects has strong potential to be operational by 2030 if effective policies to create demand and facilitate offtake are implemented.

Low-emissions hydrogen production by technology, status and likelihood of being available by 2030, based on announced projects



Notes: FID = final investment decision; CCUS = carbon capture, utilisation and storage.
Source: IEA Hydrogen Production Projects Database (September 2025).

The cost gap between low-emissions hydrogen and unabated fossil-based production remains a key barrier for project development, but it is expected to narrow. The sharp decline in natural gas prices from levels observed in 2022-23 – and the increase in the cost of electrolysers due to inflation and slower-than-expected deployment of the technology – has led to a larger cost gap with production from unabated fossil fuels, meaning that support schemes remain necessary for longer. However, the gap is expected to narrow by 2030. Renewable hydrogen in China could become cost-competitive by the end of this decade due to low technology costs and cost of capital. In Europe, the gap is also set to shrink from carbon dioxide (CO_2) prices and in areas with high renewable potential, and because natural gas prices for industrial users in the region are set to be more elevated than elsewhere. In regions where natural gas is cheaper, such as the United States and Middle East, the cost gap is set to remain larger, and CCUS is likely to be more competitive for producing low-emissions hydrogen in the near term.

China leads on electrolyser deployment and manufacturing capacity, but overseas sales face barriers

China is the driving force in electrolyser deployment and manufacturing today. Global installed capacity of water electrolysis reached 2 gigawatts (GW) in 2024, and more than 1 GW of capacity has been added on top of that through July of this year. China now accounts for 65% of global installed capacity and capacity that has reached a final investment decision. China is also home to nearly 60% of global electrolyser manufacturing capacity, with a growing offer from traditional manufacturers as well as new market entrants.

Electrolyser manufacturers outside China face headwinds, raising concerns about the health of the industry. Strong momentum in the Chinese market contrasts with prospects for manufacturers elsewhere, which are experiencing sharp reductions in revenue and increased financial losses. For some, this has led to bankruptcies or acquisitions in what may signal a coming wave of consolidation. In China, the industry is not immune to such developments; its existing manufacturing capacity of 20 GW per year is significantly above current demand, which was around 2 GW in 2024. This may also lead to consolidation in due course.

Outside of China, the cost of installing Chinese electrolysers is not significantly lower than installing those made by other producers when all factors are taken into account. The cost of making and installing an electrolyser outside of China in 2024 was USD 2 000 to USD 2 600 per kilowatt (kW), compared with USD 600 to 1 200 per kW for electrolysers manufactured and installed in China. However, the cost of equipment is just part of the total investment needed to install an electrolyser. More than half of the total corresponds to engineering, procurement, construction and contingency costs, which depend on the project location. When transport costs and tariffs are also considered, the cost of installing a Chinese electrolyser outside China is to USD 1 500 to USD 2 400 per kW – narrowing the gap with non-Chinese competitors.

Barriers preventing the use of Chinese electrolysers outside of China remain, but this may change soon. While installing electrolysers made in China can reduce upfront investment, they face efficiency and underperformance issues and need to be adapted to local standards. This can drive up operational costs, which can in turn make the overall production of hydrogen more expensive and diminish any investment cost advantages. This is currently limiting the global uptake of Chinese electrolysers, along with uncertainties related to maintenance and repairs over the lifetime of the plant. However, Chinese manufacturers are now addressing many of these barriers through innovation and exploring the expansion of manufacturing operations overseas.

Policies to create demand for low-emissions hydrogen are advancing, though enactment will be important

Momentum for hydrogen offtake agreements slowed in 2024, with new deals concentrated in refining, chemicals and shipping. New offtake agreements signed in 2024 reached 1.7 Mtpa, compared with 2.4 Mtpa in 2023. However, some preliminary agreements signed in previous years were firmed, leading to investment in production projects. Existing uses of hydrogen in the refining and chemical sectors – and the use of hydrogen-based fuels in shipping and, to a smaller extent, aviation and power generation – account for almost all firm offtake agreements announced by the private sector to date and 80% of investment in committed production projects. Tenders to procure low-emissions hydrogen yielded mixed results in 2024; tenders in the steel sector in Europe were delayed or put on hold while tenders for refining and fertilisers led to final investment decisions for production plants in Europe and India.

Policies to create demand are now being implemented, but at a slow pace. Europe leads the way on the adoption of sectoral quotas for hydrogen use in transport and industry within the EU Renewable Energy Directive (RED) and mandates for the aviation sector. India (with a focus on refining and fertilisers) and Japan and Korea (with a focus on power generation) have also started ambitious programmes. The new International Maritime Organization (IMO) Net-Zero Framework could boost the uptake of hydrogen-based fuels in the maritime sector. However, the full impact of these efforts remains to be seen and, in the short term, the IMO regulations may actually stimulate demand for liquefied natural gas or biofuels instead. The EU's RED quotas need to be transposed into national legislation by EU member states, and there will be no clear demand signal to the hydrogen sector until this has been completed, since approaches can vary.

Leading ports could be first movers on low-emissions hydrogen-based fuels for shipping

Suitable bunkering infrastructure at ports will be needed soon if ships are to adopt hydrogen-based fuels. These fuels can be a vital part of meeting the IMO decarbonisation goals, along with other fuels and energy efficiency. Their uptake in shipping will depend on strong regulatory signals, the deployment of compatible ship technologies, and expanding supply and infrastructure. As of June 2025, more than 60 methanol-powered vessels were on the water and nearly 300 more were on order books. Furthering the development of bunkering infrastructure is the next step to avoid bottlenecks in the near future.

Infrastructure upgrades to strategically located bunkering ports could cover most major trade routes. Marine fuel bunkering is highly geographically concentrated: Singapore alone supplies around one-fifth of global demand, and just 17 ports cover over 60% of the sector's refuelling needs. In addition, a large share of existing production and demand for unabated fossil-based hydrogen (refineries and chemical plants) tends to be located near ports, making them optimal places to kickstart the large-scale adoption of low-emissions hydrogen.

Analysis of existing infrastructure and its proximity to low-emissions hydrogen production reveals early opportunities. Nearly 80 ports have well-developed expertise in managing chemical products, indicating a strong readiness to also handle hydrogen-based fuels. These ports, which are widely distributed across the globe, include some of the largest in the world, such as Rotterdam, Singapore and Ain Sokhna (Egypt). More than 30 of these ports could each access at least 100 ktpa of low-emissions hydrogen supply from announced projects within 400 kilometres.

Southeast Asia is emerging as a significant and growing hydrogen market

Hydrogen demand in Southeast Asia is dominated by the chemical sector, with supply largely based on natural gas. Southeast Asia's hydrogen demand in 2024 reached 4 Mtpa, led by Indonesia, which accounted for 35%, Malaysia, Viet Nam and Singapore. Hydrogen use in ammonia production accounted for nearly half of demand, followed by refining and methanol production. Nearly 80% of demand was met with hydrogen produced from unabated natural gas, and the rest was from industrial by-product. Hydrogen production consumes around 8% of the region's gas supply and accounts for a little over 1% of energy-related CO_2 emissions.

The pipeline for low-emissions hydrogen production in Southeast Asia shows considerable promise but needs to mature. Based on announced projects, low-emissions hydrogen production could reach 480 ktpa by 2030, highly concentrated in Indonesia and Malaysia. However, only 6% of announced production has reached a final investment decision, and 60% remains at very early stages of development. One notable exception is a 240 MW electrolyser project under construction in Viet Nam – one of few projects at this scale outside of China to reach FID. Around 40% of the projects are geared for exports – mostly of ammonia, which is the target product of the large majority of the pipeline.

Existing industrial applications and shipping provide key opportunities for early adoption. The greatest opportunities to adopt low-emissions hydrogen in the region include ammonia production in Indonesia, Malaysia and Viet Nam and methanol production in Malaysia, to improve trade balances by reducing imports of natural gas and natural gas-based products; steel production in Indonesia and Viet Nam to meet growing regional demand; and maritime bunkering in Singapore to supply emerging demands in international shipping. The geographical concentration of existing applications, particularly in countries with large state-owned enterprises, provides a strong foundation for scaling up the sector. Near-term success will depend on accelerating the deployment of renewables to reduce production costs, implementing targeted policies for fuel-switching, and developing pilot projects that enable gradual progress towards commercialisation.

Recommendations

Based on progress achieved to date and the evolving challenges the sector faces, the IEA has updated its policy recommendations to help governments that want to leverage low-emissions hydrogen to meet their energy goals:

- **Maintain support schemes for low-emissions hydrogen production, with a focus on shovel-ready projects that target existing applications**. A large pool of projects targeting existing applications are ready to take investment decisions if timely support is provided to reduce the cost gap between unabated fossil-based hydrogen and low-emissions technologies. These projects could drive a rapid scaling up of low-emissions hydrogen production and enable cost reductions.
- **Accelerate demand creation for low-emissions hydrogen and hydrogen-based fuels through regulations and support schemes in key sectors**. Speeding up policy implementation to stimulate demand can facilitate offtake and underpin investment in supply. Effective measures target existing hydrogen users and high-value applications in emerging sectors, while pooling demand in industrial hubs to create scale and reduce risk. Governments and industry can cooperate to create lead markets for sustainable end-use products, unlocking early-stage adoption.
- **Expedite deployment of hydrogen infrastructure by removing barriers and leveraging early opportunities**. Comprehensive yet manageable regulatory frameworks and the introduction of financial mechanisms can help mitigate early

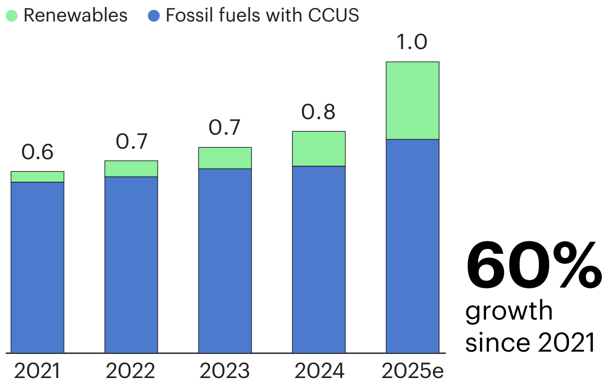
investment risks, while efficient permitting processes and improved coordination among authorities can help to reduce lead times. A focus on industrial and port clusters that co-locate production projects with pools of potential users can facilitate early deployment.

- **Enhance public support to reduce technology risk and facilitate project financing**. Governments can strengthen public finance mechanisms to reduce risks associated with early-stage technologies, which struggle with project bankability due to their lack of a proven performance record. Export credit agencies and public finance institutions can expand guarantee programmes for first-of-a-kind projects that seek to demonstrate and scale up novel technologies.
- **Support emerging and developing economies in moving up the value chain for low-emissions hydrogen-based products**. These economies hold significant potential for low-cost, low-emissions hydrogen production, but face key challenges such as limited enabling infrastructure and access to finance, as well as their reliance on exports to a global market which is developing slowly. Advanced economies can partner with emerging and developing economies to encourage new domestic use cases (such as fertiliser production) and open export opportunities for hydrogen-based products. This could enable emerging and developing economies to move up the value chain; enhance their energy and food security by reducing import dependencies; and boost economic growth.

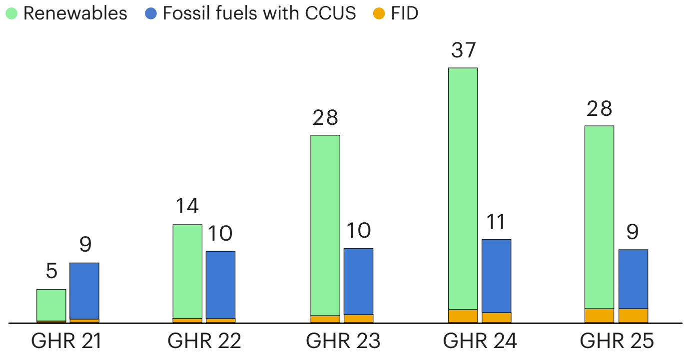
Global Hydrogen Review Summary Progress

Production

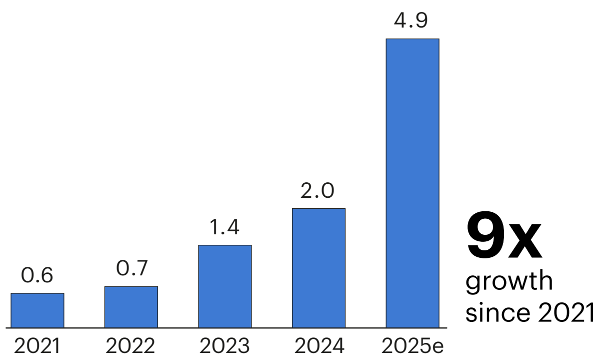
Low-emissions hydrogen
Mtpa



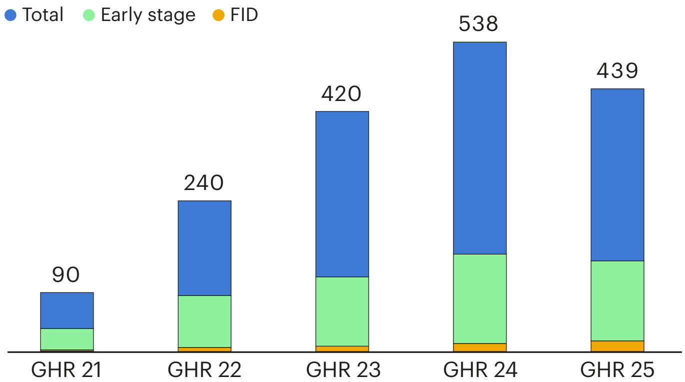
Low-emissions hydrogen production from announced projects by 2030
Mtpa



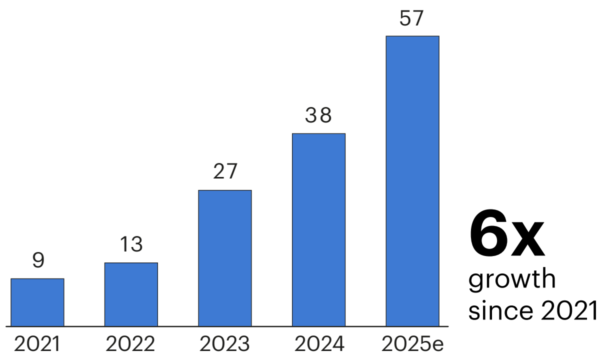
Electrolyser installed capacity
GW



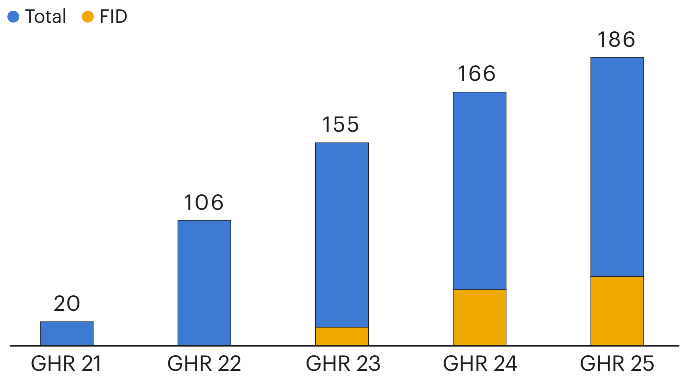
Announced electrolyser projects by 2030
GW



Electrolyser manufacturing capacity
GW/yr

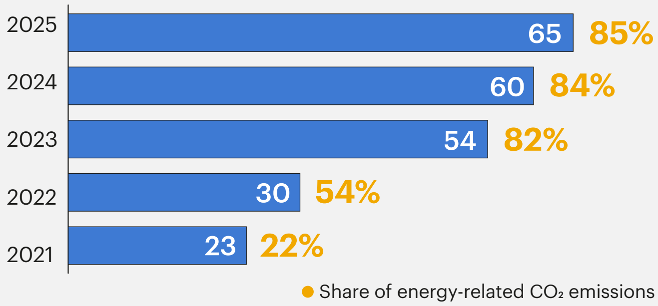


Announced electrolyser manufacturing capacity by 2030
GW/yr



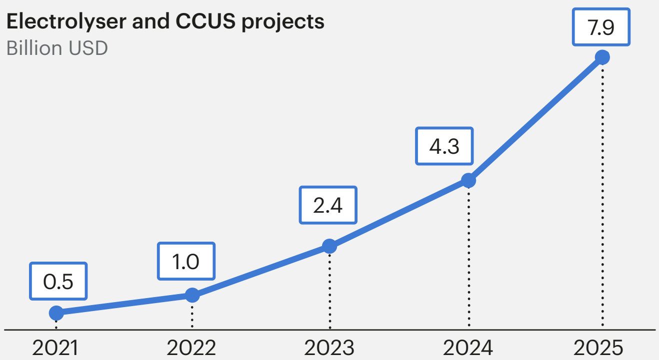
Policies

Number of hydrogen strategies



Investment

Electrolyser and CCUS projects
Billion USD



Note: 2025e = Estimated based on announced projects. FID = Final Investment Decision.

Five key questions about hydrogen

Is the slow progress of projects derailing the hydrogen sector?

The hydrogen sector has seen impressive momentum in recent years, particularly in early 2020, when a wave of ambitious government commitments was met with a similarly vigorous response from the private sector, with hundreds of announcements of projects for the production of low-emissions hydrogen.

However, more recently, negative news from the sector has repeatedly made headlines, including project delays, cancellations, downward revisions of ambitions for the adoption of low-emissions hydrogen, company bankruptcies and backsteps on policy-making. As a result, a gloomier outlook has taken hold among government and industry, with fears that that the sector has stalled, and that the efforts of the past few years have been fruitless. There are concerns that hydrogen has simply gone through another "hype" cycle, just like in the 1970s, 1990s and early 2000s.

The very high short-term expectations from a few years ago have not been met. For example, at the time of the Global Hydrogen Review 2022, governments had adopted targets that cumulatively accounted for 190 GW of installed electrolysis capacity and 1.2 million fuel cell electric vehicles (FCEVs) by 2030. However, installed electrolysis capacity was at almost 700 MW at the end of 2022; the FCEV stock had barely surpassed 70 000 vehicles.

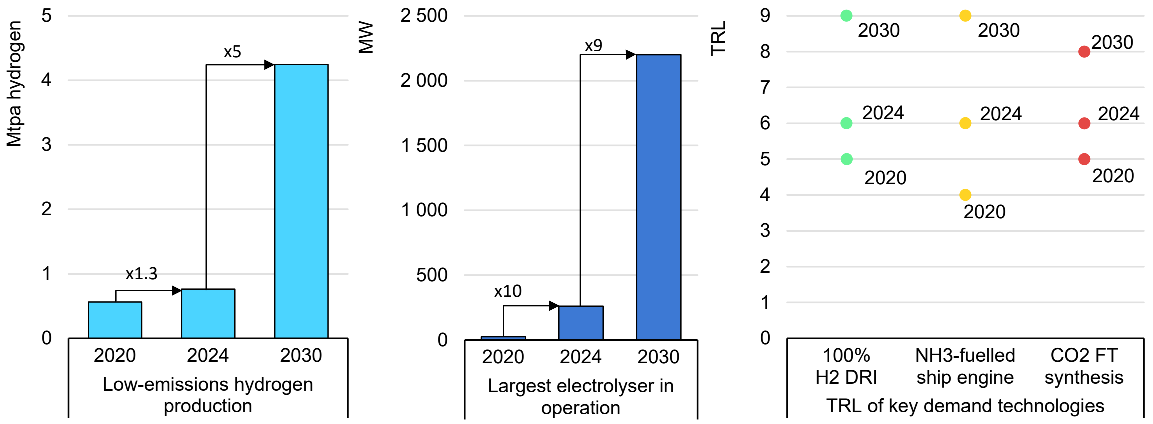
These ambitions set the bar very high for a nascent sector that needs to construct new value chains almost from scratch. New products entering the market often face barriers such as high costs for first movers and a lack of adequate regulation and infrastructure. The process of adopting innovative technologies can be lengthy and uneven, typically combining rapid breakthroughs with periods of sluggish development. This applies even in recent success stories in clean energy technology development, such as for solar PV, which took 25 years from market introduction to reach a 1% share of a national electricity supply market for the first time. While the challenges facing the hydrogen sector have led to slower-than-targeted deployment, a closer look at the evidence shows that – rather than stalling or faltering – the sector is progressing and reaching important milestones:

- The size of projects under development is significantly scaling up: When we published the Global Hydrogen Review 2021, the largest electrolyser in operation in the world was the first phase (30 MW) of a project developed by Ningxia Baofeng Energy Group in People's Republic of China(hereafter, "China"). In July

2025, Envision Energy commissioned the world's largest electrolysis project (500 MW) in China, using off-grid renewable electricity. The world's largest project under construction, the NEOM Green Hydrogen Project in Saudi Arabia, is expected to scale the technology beyond 2 GW by its targeted operation in 2027 – representing scale-up by 75 times in just 6 years.

- Back in 2020, adoption of low-emissions hydrogen was uncertain and there were no offtakes. In contrast, a number of offtakes have been signed in the past few years, some of which are firm, long-term offtakes. These have enabled projects to move past final investment decision (FID) to supply traditional sectors (refining, ammonia production) as well as novel applications such as shipping.
- Technology development is progressing at an impressive speed. This year, the number of technologies advancing by at least one technology readiness level (TRL) is the highest it has ever been since we began publication of the Global Hydrogen Review. This is particularly important on the end-use side, where several technologies in steel, shipping and aviation are being demonstrated and can reach commercialisation before 2030, unlocking large demands for low-emissions hydrogen.

Progress in low-emissions hydrogen production, size of electrolyser projects, and technology development and expected status, 2020-2030



Notes: FT = Fischer-Tropsch; H_2 DRI = direct reduced iron using 100% hydrogen; TRL = technology readiness level. Low-emissions hydrogen production includes historical values for 2020 and 2024 and an estimate of the potential production in 2030 from projects that have at least reached final investment decision (FID) and target operation before 2030. Largest electrolyser in operation for 2020 and 2024 considers projects already in operation at the end of those years and the largest project under construction today that aims to start operation before 2030. TRL of key technologies for 2020 and 2024 includes the real status of the technologies at the end of the year, and for 2030 the expected TRL of each technology based on innovation milestones announced by companies developing each technology.

The hydrogen sector is moving forward and achieving milestones across the value chain.

The short-term prospects for the sector are positive: based only on projects that are operational, have reached FID or are under construction, production of low-emissions hydrogen is expected to grow fivefold in just 6 years (from 0.8 Mtpa in

2024 to 4.2 Mtpa by 2030). While this falls far short of the ambitions announced in the early 2020s, it demonstrates impressive growth for a nascent sector.

Nevertheless, this growth is not equally distributed across the world. Some countries and regions are moving at a faster pace, like China, Europe, India, Japan, Korea and North America, whereas in others, progress is lagging, and adoption at scale will probably take place only after 2030. In addition, even among the frontrunners, there remain unresolved challenges. These include the high production cost of low-emissions hydrogen and hydrogen-based fuels when compared with unabated fossil-based incumbents, uncertainty around demand, unclear and complex regulation, and limited available infrastructure for delivery to end-users. However, on balance, the signs of progress still outweigh the negative news. This is an encouraging sign for a sector that can play an important role in meeting government commitments to address climate change and boost energy security, at a moment when geopolitical tensions are rising.

How can low-emissions hydrogen demand take off?

Stable, predictable demand is a key lever for investment in low-emissions hydrogen production, along with other enabling factors like solid project partners, reliable technology providers, access to low-emissions energy, a clear and supportive regulatory framework and available infrastructure. Without robust demand, producers of low-emissions hydrogen will not secure sufficient off-takers to underpin large-scale investments.

In spite of this, demand for low-emissions hydrogen currently remains low and uncertain. Offtake agreements are mostly preliminary, with only a limited number of firm agreements that include binding conditions for both suppliers and off-takers. Such agreements account for less than 2 Mtpa, equivalent to around 5% of the potential production that announced projects could achieve by 2030. This lack of dependable demand could jeopardise the viability of the entire low-emission hydrogen industry.

Governments have started announcing and implementing measures to stimulate demand for low-emissions hydrogen, and industry is responding with a number of initiatives to accelerate adoption. However, the results of these efforts have been mixed. Some positive outcomes have come from tenders in the refining sector. For example, TotalEnergies has contracted more than 200 ktpa of renewable hydrogen to be used in its European refineries and plans to finalise agreements for another 300 ktpa by the end of 2026. In India, several state-owned companies launched tenders to procure renewable hydrogen last year, with three of them already awarded and one leading to an FID in a production project. However, a number of tenders launched in the steel sector have either not yet been awarded, or have been put on hold due to bids being significantly higher than expected and problems resulting from a lack of available infrastructure. In addition, several initiatives for international co-operation to aggregate demand have been launched in recent years, but they are progressing slowly, and there are no noteworthy results that can send a strong demand signal to producers.

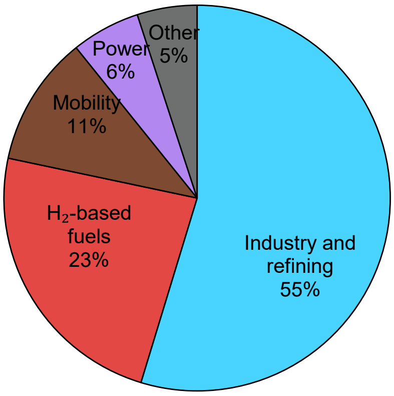
The cost gap between low-emissions hydrogen and unabated fossil-based hydrogen in traditional applications (such as refining and chemical products), and between the use of low-emissions hydrogen-based fuels and unabated fossil fuels in new applications (such as steel, shipping or aviation) remains a barrier to switching to low-emissions hydrogen. Overcoming this requires policy action, but so far this has been largely insufficient, geographically limited and, on many occasions, still uncertain. However, some carefully targeted policy interventions could be a game-changer in unlocking large demand in the short term:

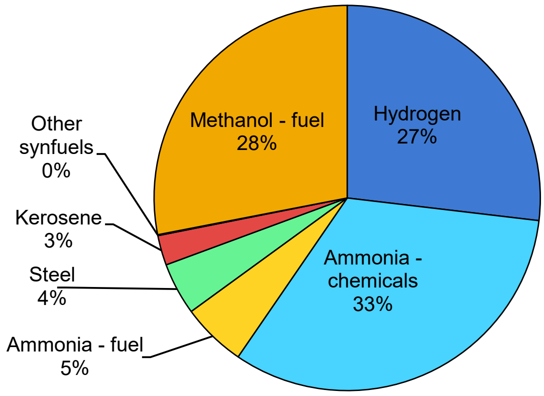
- **Focus on existing hydrogen uses**. These are ready to take up low-emissions hydrogen at scale, as technology barriers are lower, and represent more than half of the committed investment in low-emissions hydrogen production. Replacing existing dedicated hydrogen production using unabated fossil fuels[1] with production using water electrolysis would require about 880-1130 GW of electrolysis capacity, while retrofitting existing production assets with carbon capture, utilisation and storage (CCUS) would require a capacity for CO_2 capture and storage of 720-820 Mt per year.
- **Unlock new opportunities through public procurement and support the creation of lead markets**. Public procurement is a powerful policy tool to stimulate demand. For example, the public sector accounts for 25% of steel demand globally, but governments are not yet using this opportunity to its full potential. Putting this buying power behind end-use products that require low-emissions hydrogen in their production (such as fertilisers, steel or shipping and aviation fuels) can unlock significant demand in the near term. More than three-quarters of today's firm offtake agreements that can trigger demand are targeting industrial end products (fertilisers, steel, or other chemicals) or hydrogen-based fuels (ammonia, synthetic methanol and synthetic kerosene).
- **Take a holistic approach in policy design**. Incorporating offtake as an eligibility criterion in support schemes for low-emissions hydrogen production projects can act as a filter to ensure that only robust projects with bankable offtake reach the final stages of the selection process. This would maximise the chances of selecting projects with a strong likelihood of coming to fruition.
- **Leverage international transport regulations**. International transport offers important opportunities to accelerate the adoption of low-emissions hydrogen-based fuels through co-ordinated global standards. International regulations help create level playing fields, ensuring market participants face consistent rules

[1] This accounts for more than 80 Mtpa, excluding by product-hydrogen and the production of hydrogen for co-production of ammonia and urea, which requires CO_2 for the urea synthesis.

across jurisdictions. The International Maritime Organization Net-Zero Framework can be a decisive first step in this direction. Depending on the technical details of its final guidelines (to be developed in the next few months), this framework could significantly boost demand for low-emissions fuels in international shipping. The International Civil Aviation Organization can follow a similar approach, developing a regulatory framework that complements existing efforts such as its voluntary market-based Carbon Offsetting and Reduction Scheme for International Aviation.

Investment in low-emissions hydrogen production by intended use and offtake agreements for low-emissions hydrogen by end product





Notes: "Other" intended uses includes undisclosed end uses. Investment values are estimated annualised spending on projects that had taken final investment decision by July 2025.

Traditional hydrogen applications represent "low-hanging fruit" that could stimulate demand for low-emissions hydrogen in the near term.

Policy action can act as an initial anchor for the creation of lead markets, but the private sector also has a role to play. There are already consumers willing to pay small premiums for sustainable products (as seen with organic foods in Europe and in sectors like the automotive industry), and they can be reached through sectoral initiatives to develop lead markets for the products that can gain market traction. For example, using low-emissions hydrogen in fertiliser production leads to a negligible increase in the price of a cup of coffee, and using it in steel production leads to an increase of approximately 1% in the final price of an electric vehicle. Manufacturers of end-use products can boost demand for low-emissions materials (and ultimately low-emissions hydrogen) by committing to long-term purchases. Sectoral initiatives should set transparent, measurable demand goals and co-ordinate stakeholders across the value chain to translate pledges into concrete implementation.

How fast can emerging economies really turn hydrogen ambitions into timely deployment?

Low-emissions hydrogen offers emerging markets and developing economies (EMDEs) an opportunity to both support domestic decarbonisation and position themselves as competitive players in clean energy trade. Africa, Latin America and Southeast Asia, home to 35% of the global population but less than 20% of global GDP and just 16% of energy demand, are all assessing how to seize this opportunity, building on abundant renewable energy potential and competitive labour costs.

The three regions have different starting points. Latin America benefits from a largely decarbonised power sector, with renewables supplying 63% of electricity generation in 2024, nearly twice the global average. In contrast, renewable shares in Southeast Asia and Africa remain at 25% (despite their hydropower shares being slightly above the global average) as deployment of wind and solar PV has been limited to date. Latin America is a net importer of natural gas, with a deficit that widens since the region became a net importer in 2010. Southeast Asia and Africa, historically exporters, have seen a steady decline in their gas trade balance since the past decade, and Southeast Asia may become a net importer in the latter part of the 2020s. Low-emissions hydrogen could help to reduce import dependency and strengthen energy security.

The three regions have relatively similar levels of hydrogen consumption today, at around 3-4 Mtpa each. Combined, they account for approximately 11% of global hydrogen demand, although the characteristics of this demand differ notably from the global average. Worldwide, over 40% of hydrogen is used in oil refining, but this share is significantly lower across these regions. This is particularly visible in Africa, where refining accounts for just 12% of hydrogen use, given that a large share of oil products are imported (meeting 40% of domestic demand).

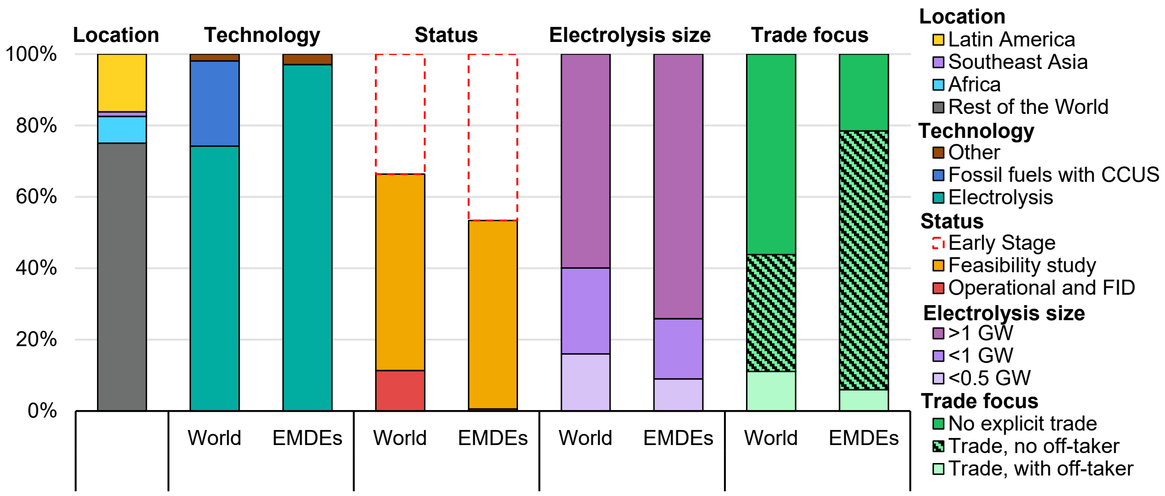
If all announced projects are realised, low-emissions hydrogen production in Africa, Latin America and Southeast Asia could exceed 9 Mtpa by 2030, representing almost 25% of the global total. However, while more than 9% of announced projects worldwide now have committed investments, the share in these regions is far lower, at just 0.5%, raising questions about near-term viability. New analysis in this report finds that only 5% of the projects in EMDEs have at least moderate potential to be operational by 2030, with most expected to materialise only later.

Several factors are slowing progress toward committed investments:

- **Heavy reliance on export markets**. Around 80% of announced projects in these regions are geared towards exports – nearly double the world average – making them dependent on international demand that has yet to materialise at scale.

- **Slow progress in renewable energy integration**. In 2024, these regions accounted for just 6% of new wind and solar PV capacity globally. This raises questions about their readiness to support large-scale electrolytic hydrogen production, which would entail accelerated deployment of renewables.
- **Financing challenges**. Realising all the projects in the pipeline by 2030 would require 420 GW of electrolysis capacity and more than USD 1 500 billion, equivalent to the global investment in new power generation in 2024. Yet in 2024, these regions attracted less than 9% of that global investment in new power generation, partly due to the cost of capital for energy projects, which can reach 15%, compared to 5-7% in advanced economies.

Announced projects for low-emissions hydrogen, 2030



Notes: EMDEs = emerging markets and developing economies; CCUS = carbon capture, utilisation and storage; FID = final investment decision.

Projects in EMDEs focus almost exclusively on electrolysis, are larger and mainly export-oriented, but remain at earlier stages of development, with limited committed investment.

Tapping into the potential economic opportunities of low-emissions hydrogen for EMDEs will require a shift in strategic focus to bring projects to fruition. While there is no one-size-fits-all approach, several common considerations can help guide countries in aligning their hydrogen plans with broader development goals:

- **Lay the groundwork through electricity access and renewable integration.** Projects in the pipeline in these regions would require today's solar PV and wind capacity to more than double in Southeast Asia, almost triple in Latin America and increase more than tenfold in Africa. Some 40% of Africa's population still lacks access to electricity, and both Africa and Southeast Asia have lower-than-average renewable energy shares. Strengthening the power grid and developing expertise in renewables are critical first steps, and can contribute to building domestic supply chains and a skilled workforce.

- **Lower the cost of capital to improve competitiveness**. In EMDEs, financing costs are up to three times higher than in advanced economies, making projects uncompetitive. Long-term offtake agreements can help to reduce commercial risk and provide revenue certainty. Developers may form consortia in which off-takers act as equity partners, as seen in some advanced projects in other regions. Governments can support offtake certainty through public procurement for domestic supply or, in importing countries, by promoting supply diversification to foster participation from EMDEs. Clear regulation, streamlined permitting and investment in enabling infrastructure can further de-risk projects and attract foreign direct investment. Development Finance Institutions can expand concessional loans, guarantees and first-loss facilities[2] to improve bankability and mobilise private capital through blended finance.
- **Assess the role of domestic markets as an anchor for early low-emissions hydrogen deployment**. EMDEs have large demands for hydrogen-based products that are often met through imports. For example, in 2022, excluding Trinidad and Tobago (a major producer and exporter), Latin America imported 85% of its nitrogen-based fertilisers, valued at nearly USD 11 billion. Most African countries also rely heavily on imports, despite a few being large ammonia exporters. Producing fertilisers domestically using low-emissions hydrogen could improve access, reduce dependence on imports – including for food, which accounted for around USD 50 billion in net imports across Africa in 2024 – and lower exposure to price volatility. In the three regions, around 7% of natural gas consumption is used for hydrogen production, and replacing fossil-based hydrogen would ease pressure on natural gas trade balances.
- **Prioritise export pathways that add value to raw commodity exports**. Rather than focusing solely on hydrogen or ammonia molecule exports, countries can pursue value-added derivatives that are easier to ship and have higher prices. For example, in Brazil and sub-Saharan Africa, high-grade iron ore reserves offer an opportunity to use low-emissions hydrogen to produce direct reduced iron (DRI), exported as hot briquetted iron. Today, DRI sells for roughly four times the price of iron ore, with potential for even higher margins when accounting for low-emissions premiums. Developing new iron ore mines can take up to a decade, so early opportunities are limited to regions with existing or advanced mining projects.

What is a pragmatic policy response to the barriers facing hydrogen?

Policy support for low-emissions hydrogen is now moving from announcements to specific programmes and tenders, and making progress along the entire value chain. On the supply side, some programmes (in the European Union and United Kingdom) have already issued two rounds of funding. With regards to

[2] A first-loss facility is a financing mechanism in which an investor, such as a Development Finance Institution, agrees to absorb initial losses on a project to reduce risk for other investors, encouraging their participation.

infrastructure, measures are providing regulatory clarity (European Union) and grants for development (Japan). To boost demand, there is increasing attention to industrial applications where hydrogen is already used that could create economies of scale (Austria, China, Finland, France, India). Emerging economies have used measures such as land concessions for hydrogen production with special rights and advantages (Morocco, Oman, Mauritania, Jordan), tax incentives (Mauritania) and loan guarantees (Brazil). Policy support has helped projects to move forward and reach FIDs. Examples include 1.4 Mtpa of ammonia from natural gas with CCUS in the United States, a 100-MW electrolyser in Germany and a 2.5 Mtpa steel plant in Sweden.

Comparison of hydrogen policy approaches adopted across selected hydrogen markets

Category	European Union	United States	China	Japan	India
Targets	2030: 40 GW of domestic electrolyser capacity	-	2025: 100-200 kt green hydrogen production	2030: 3 Mtpa of hydrogen consumption	2030: 5 Mtpa green hydrogen production
Supply	European H_2 Bank IPCEI Innovation Fund	Inflation Reduction Act (45V, 45Q, 45Z, 48C)	Provincial subsidies; roll-out through SOEs	CfD scheme	Financial support for electrolysis, ammonia, manufacturing
Infrastructure	H_2 and gas markets decarbonisation IPCEI; AFIR; CEF	Support for hydrogen refuelling stations	Support for new hydrogen pipelines	Clusters support scheme; CAPEX subsidy for storage	Hydrogen Valley Innovation Clusters
Demand	RED; ReFuel Aviation; FuelEU Maritime; CISAF; IPCEI	Loan guarantees, tax credits, ZEV mandates	Implementation plan for industry; FCEV tax exemptions/subsidies	Hub support; tax credits for industry; FCEV subsidies	Guaranteed offtake through SECI
Certification	Delegated Acts for renewable and low-carbon hydrogen	Clean Hydrogen Production Standard (CHPS)	Clean and Low-Carbon Hydrogen Energy Evaluation Standards	Hydrogen Society Promotion Act	Green Hydrogen Standard
R&D	Clean Hydrogen Partnership	Offices of Energy Efficiency, Renewable Energy, FECM	Demo programmes across the entire value chain	Green Innovation Fund	R&D scheme of National Green Hydrogen Mission

Notes: AFIR = Alternative Fuels Infrastructure Regulation; CEF = Connecting Europe Facility; CfD = Contract for difference; CISAF = Clean Industrial State Aid Framework; FCEV = Fuel cell electric vehicle; FECM = Fossil Energy and Carbon Management; IPCEI = Important Projects of Common European Interest; RED = Renewable Energy Directive; SECI = Solar Energy Corporation of India; SOE = State-owned enterprise; ZEV = Zero Emission Vehicles.

The policy landscape varies across jurisdictions, reflecting differing domestic constraints and priorities.

The sector is still nascent, and different regions have taken different approaches to policy development. Given the versatility of hydrogen, there is no “silver bullet” in terms of effective policy instruments, and the final choice will depend on the specific country context. The European Union and the United Kingdom currently have the most comprehensive approach, addressing the entire value chain, as well as cross-cutting aspects like innovation or skills. However, policy support in Europe is fragmented across different pieces of legislation and policies that may also apply to products other than hydrogen (e.g. carbon pricing), which can make legislation difficult to navigate. Japan also has a comprehensive approach guided by the Hydrogen Society Promotion Act, with a contracts for difference scheme to close the cost gap for low-emissions hydrogen and provide long-term (15-year) certainty. This is complemented by support for infrastructure, hubs and the demand side (industry and power). The United States and Australia have followed a similar approach, with tax incentives for the supply side and grants for hubs on the demand side, albeit with less emphasis on infrastructure. China has a unique approach, with support through state-owned enterprises for industrial use of renewable hydrogen, and grants and a reward scheme for provinces rolling out fuel cell electric vehicles (FCEV). India has the Strategic Interventions for Green Hydrogen Transition (SIGHT) Programme, an overarching scheme with fixed premiums and grants for supply and electrolyser manufacturing. Tax incentives and administrative measures are the most common instrument across other emerging economies.

This first-of-a-kind implementation of hydrogen policies has also entailed some delays and revisions. This creates uncertainty for project developers and investors, which can affect project execution. For example, in the European Union, the transposition of the Renewable Energy Directive to national legislation has taken more than 4 years; in India, support for hubs is being scaled back, and conditions for financial support for ammonia supply have been revised several times.

Hydrogen policies must balance speed of implementation with ensuring that deployment meets policy objectives. Very firm policies may provide clarity but can slow down market development. The hydrogen market is expected to evolve quickly, so policies need to be adaptive, with short review cycles to account for market developments. This approach can provide long-term clarity while leaving room for experimentation during the early stages.

The barriers facing low-emissions hydrogen are common across markets. There is a cost gap with incumbent fossil fuel pathways in both production and use. Co-ordination can also be challenging. Firstly, among stakeholders across supply, infrastructure and end use, who need to align project development timelines. Secondly, among producers along the supply chain, from raw materials to end products, who need to evaluate where consumers are willing to pay for low-emissions products in order to close part of the cost gap. This is necessary as low-emissions products do not yet have sufficient demand to create economies of scale and trigger cost reductions through learning-by-doing, nor a high enough premium to reward developers.

Similarly, priorities for the short term are clear and also common across markets. Options for addressing the cost gap include grants and subsidies, which have already been used extensively by advanced economies. Other options like loan guarantees, concessional loans, export credit facilities and public equity investments can also be useful to reduce the investment risk and lower the cost of capital, which is crucial given the high capital intensity of hydrogen assets. For demand creation, quotas, mandates and carbon contracts for difference are among the most-used instruments. One policy measure that remains relatively unexplored is public procurement, which could trigger demand for hydrogen in steel production, heavy-duty transport and aviation. The creation of hydrogen hubs has mostly been a source of funding thus far, but they also provide an opportunity to address the co-ordination barrier and aggregate demand from several users. This can lower the commitment required from each user and spread the offtake risk across several players. For most of these policies to be effective, it is necessary for hydrogen producers and buyers to be able to differentiate low-emissions hydrogen by tracking the GHG emissions along the value chain. Several regions already have a certification scheme in place, and a more standardised approach could be achieved once the forthcoming ISO methodology is published in 2025/2026.

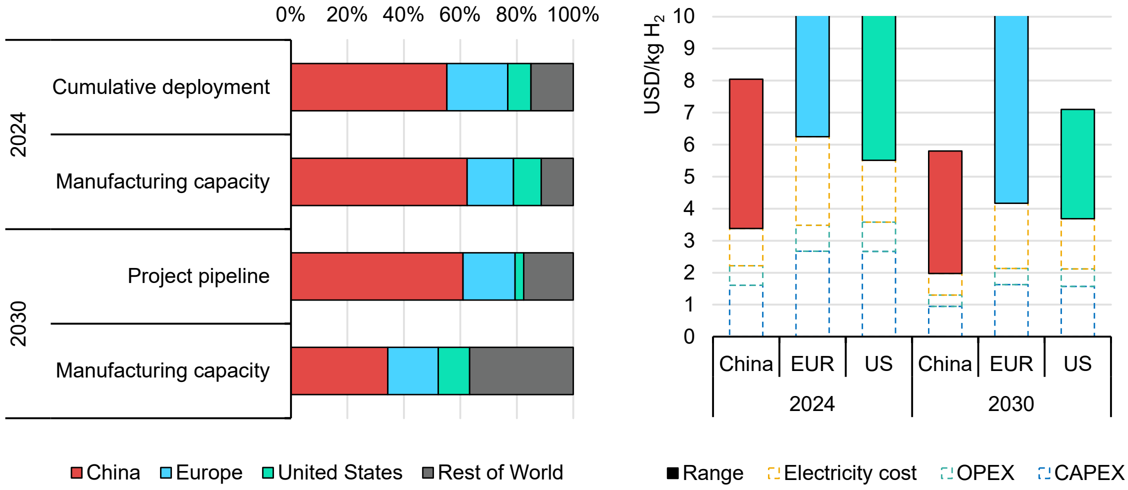
China and electrolysers: the sequel to solar PV and EVs?

Today, China is the global leader in electrolyser manufacturing capacity and deployment, as well as production cost for renewable hydrogen, echoing its success in manufacturing and deployment of solar PV and electric vehicles (EVs). China holds nearly 60% of global electrolyser manufacturing capacity, equivalent to more than ten times the historical installed electrolyser capacity in 2024. China started deploying water electrolysis commercially in 2021, and by 2023, it already had over half of installed electrolyser capacity worldwide. From 2022 to 2024, China accounted for two-thirds of the electrolyser capacity reaching FID.

China can also produce renewable hydrogen at a lower cost: The cheapest renewable hydrogen costs about 40-45% less to produce in China than in Europe or the United States. This is mainly due to lower electricity prices, which result from lower capital expenditure (CAPEX) and a lower cost of capital for renewables. In 2023, investment costs for solar PV and onshore wind were up to 40% lower in China than in the rest of the world; the cost of capital for solar PV in China was nearly half that of the United States or Spain (with a smaller difference for onshore wind). Economies of scale and experience with large construction projects enable low costs for the balance of plant for the electrolyser, and for engineering, procurement and construction, which together represent 80-85% of the total CAPEX.

Importantly, China is today the world's largest hydrogen market, accounting for almost one-third of global demand. Other stand-out factors include the country's highly developed manufacturing supply chain; companies that have manufacturing experience and financial resources from the renewable sector and that are now entering the hydrogen market; and supportive government policy to create large demand for electrolysers, just like for solar PV and batteries.

Electrolyser manufacturing capacity and deployment (left) and renewable hydrogen production costs (right), by region, 2024-2030



Notes: Project pipeline based on operational projects, projects under construction and with a final investment decision. 2030 production costs based on the Stated Policies Scenario (STEPS).

China currently leads on electrolyser deployment, manufacturing capacity and renewable hydrogen production costs, and is expected to maintain its cost lead through 2030.

A look at the projects in the pipeline to 2030 that are under construction or have reached FID suggests China will increase its share of global installed capacity, although there is less visibility on future projects in China than in other regions. In contrast, China's share of electrolyser manufacturing capacity is expected to decline to about one-third of global capacity by 2030 as global capacity expands from nearly 38 GW/yr in 2024 to 186 GW/yr in 2030 (for reference, projects under construction and with FID have a cumulative capacity of 26 GW), despite the market being largely oversupplied. Excess capacity is now leading to consolidation among original equipment manufacturers (OEMs) outside China.

Despite their low costs, there are signs that electrolysers made in China might not supply other markets at scale in the short term. First, electrolysers are bulky, which makes trading them globally difficult. Many OEMs plan to build manufacturing facilities in countries that are also expected to have strong demand, avoiding the need to ship units worldwide. As well as reducing the risk of delays and costs related to shipping, this also simplifies maintenance and repairs, facilitating access to specialist support and troubleshooting. Second, Chinese electrolysers have struggled with efficiency and underperformance, and do not always comply with standards in the rest of the world. Compliance-related upgrades reduce their cost advantage, though top manufacturers are expected to close this gap in a few years. Third, electrolysers represent 55-65% of the levelised cost of hydrogen production, but 60% of the investment required is for engineering, procurement and construction, regardless of equipment origin. The stack only represents 15-20% of the total investment. Using imported Chinese stacks in Europe, for example, would lower costs by just 3-13% compared to using domestically manufactured stacks.

There are other reasons to believe that electrolysers will not follow the same trends as solar PV and EVs. The cost decline for electrolysis is expected to be much more gradual than solar PV or batteries, since the bulk of the CAPEX is in standard equipment (e.g. vessels, heat exchangers, power converters), with less room for cost decreases. While electricity is the main cost driver, and renewables will continue to get cheaper, cost reductions in the future will be smaller than in the past decades. This also means that technology improvements will have a smaller impact on the levelised cost. Hydrogen has far less infrastructure available than electricity, meaning co-ordination is needed along the value chain for deployment, which could be an additional hindrance compared to power technologies. While electrolysers are modular, the combination of strong economies of scale and large cost gaps across applications could limit their deployment to industrial applications (without the equivalent of phone batteries or rooftop solar PV).

Chapter 1. Introduction

Introducing the fifth edition of the Global Hydrogen Review

Since the launch in 2019 of the IEA's flagship report *The Future of Hydrogen*, the global conversation on hydrogen has evolved. Hydrogen has gone from being a niche energy carrier to a strategic opportunity in global energy systems, supporting progress towards climate and energy security goals, as well as industrial competitiveness. The sector has significantly advanced since the first edition of the IEA's Global Hydrogen Review in 2021, with low-emissions hydrogen[3] production projects multiplying from a handful of demonstration projects to more than 200 final investment decisions by the end of 2024.

Nevertheless, growth remains uneven and has not met all expectations, with cost uncertainty, geopolitical dynamics, evolving regulatory frameworks, and persistent infrastructural gaps being among the key factors holding back additional growth. Like other clean energy technologies, the sector is also likely to face new challenges as government budgets start to reflect other emerging and urgent priorities.

This fifth edition of the Global Hydrogen Review takes stock of the progress to date and explores the challenges ahead, in order to provide a thorough assessment of the level of hydrogen adoption that could be achieved by the end of this decade. This is used to inform recommendations on the priority areas that require further efforts to maximise development, especially at a moment when there are other demands on available government support.

The Global Hydrogen Review in brief

The report opens with an updated overview of hydrogen demand and production patterns worldwide. Although global demand for hydrogen continues to increase, use remains predominantly focused in established sectors such as refining and chemicals. These sectors have shown noteworthy progress in the adoption of low-emissions hydrogen, but global offtake is showing signs of losing traction in the absence of targeted policy interventions to stimulate demand. The majority of hydrogen is still produced from unabated fossil fuels, despite cleaner alternatives gaining attention. Low-emissions hydrogen production has expanded slowly in recent years, with some projects being delayed or even cancelled. Despite these

[3] See the annex for details on the definition of low-emissions hydrogen in the Global Hydrogen Review.

setbacks, production is poised to accelerate from this year onwards. Investment decisions are being made at a gradually increasing pace, yet project developers continue to encounter substantial challenges, with slower-than-expected deployment limiting cost reductions. As a result, only a small share of all announced projects are expected to be operative by 2030.

The report further examines the evolution of hydrogen trade and infrastructure. Governments in Europe, Japan and Korea are trying to kick-start trade in low-emissions hydrogen and hydrogen-based products through publicly backed competitive offtake, although this is not yet translating into investment decisions for trade-oriented projects. In addition to challenges related to costs, demand and regulation, limited progress on infrastructure development is also holding back trade-oriented projects. Some infrastructure developments are taking place in Europe and the People's Republic of China (hereafter, "China"), but they are still scarce, due to slow market development and challenges related to costs, regulation and public acceptance.

The report also highlights recent trends in sectoral investment and technological advancement. Investment in low-emissions hydrogen is accelerating, with global project spending rising in 2024 and further growth expected in 2025, although venture capital has declined since 2023. Development finance institutions continue to support emerging markets and developing economies to facilitate the development of low-emissions hydrogen projects, though the first results in terms of investment decisions remain to be seen. On the innovation side, the number of technologies moving up at least one technology readiness level in the past year is higher than in any other edition of the Global Hydrogen Review, and new milestones are being reached across the whole value chain.

The report's tracking component concludes with a wide-ranging policy review, summarising the principal legislative and regulatory measures introduced since the last edition of the Global Hydrogen Review, and assessing their likely impact on the sector's future trajectory.

Finally, this year's report includes a special focus chapter on Southeast Asia, which explores the potential of the region for the production of low-emissions hydrogen and presents the target capacity of announced projects in the pipeline. It reviews the status of hydrogen policy in the region, and explores potential options for the adoption of low-emissions hydrogen and hydrogen-based fuels and products in the near term, including how these developments could create economic opportunities and reduce import dependencies.

The CEM Hydrogen Initiative

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

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

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

Chapter 2. Hydrogen demand

Highlights

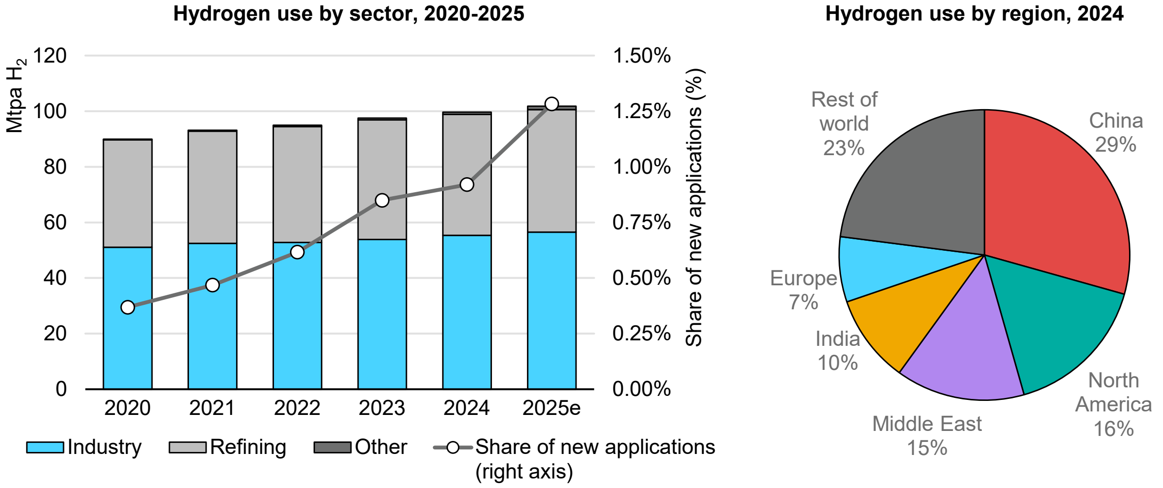
- Global hydrogen demand reached almost 100 Mt in 2024 and is expected to surpass that milestone in 2025. This increase is being driven by demand for industrial products that use hydrogen as a feedstock, rather than being the result of successful implementation of energy and climate policies.
- Demand is still almost exclusively from established sectors (refining, ammonia, methanol and fossil-based direct reduced iron [DRI]), with demand for new applications (biofuels upgrading, new industrial uses, mobility, power or synthetic fuels) growing but from a very low base – less than 1% of demand.
- Low-emissions hydrogen use increased by nearly 10% in 2024 but remains at less than 1% of total demand due to cost challenges and insufficient policy support. Policy initiatives in the European Union, Japan and Korea, and forthcoming measures from the International Maritime Organization (IMO) can accelerate ramp-up, but their impact will only be seen through implementation.
- Offtake momentum slowed, with signed deals covering 1.7 Mtpa H_2 in 2024, down from 2.4 Mtpa in 2023, only 20% of which were firm agreements. Tenders to procure low-emissions hydrogen yielded mixed results, with positive developments in refining, and uncertain outcomes on steel and fertilisers.
- Refining and the chemical sector lead the way in the adoption of low-emissions hydrogen. Based on projects that are operational, under construction or have reached final investment decision (FID), more than 2 Mtpa is expected to be consumed in refineries and industrial facilities by 2030. This could be complemented by additional supply provided by merchant projects.
- In road transport, heavy trucks remain the only fast-growing market for fuel cell electric vehicles, despite their higher total costs of ownership when compared to battery electric or diesel trucks. China remains the leader, with almost 95% of the world's fuel cell commercial vehicles stock.
- In shipping, the fleet of ships able to use hydrogen-based fuels is growing and offtake agreement activity has increased, but concerns about supply availability are slightly slowing down momentum. The recent approval of the IMO Net-Zero Framework could provide a boost, but its impact is uncertain, as it may favour first-generation biofuels or even liquefied natural gas (LNG) in the short term.
- In the power sector, progress remains slow and mostly concentrated in Japan and Korea, where policy support is helping first movers to progress with projects and building on learning from setbacks under early support programmes.

Overview and outlook

Hydrogen demand grew again in 2024, but remains concentrated in traditional applications

Global hydrogen consumption reached almost 100 Mt in 2024, just over 2% more than in 2023 (Figure 2.1). This decades-long upward trajectory (which was only interrupted by the Covid-19 pandemic) shows no sign of changing; we estimate that global hydrogen demand is set to exceed 100 Mt for the first time in 2025.

Figure 2.1 Hydrogen demand by sector and by region, 2020-2025



Notes: "Other" includes transport, power generation, production of hydrogen-based fuels, buildings and biofuels upgrading. The estimated value for 2025 (2025e) is a projection based on trends observed until July 2025.
Sources: IEA analysis based on data from Argus Media Group, All rights reserved, International Fertilizer Association, World Steel Association.

Global hydrogen demand keeps rising but remains concentrated in traditional applications in refining and the chemical sector.

Hydrogen demand by region remained broadly consistent with previous years. China was the largest consumer, with more than one-quarter of total demand (exceeding 29 Mt)[4], almost twice that of North America, the second-largest user with around 16 Mt. China and North America experienced modest growth (2% and 0.5% respectively), while Europe demand remained almost the same as in 2023. The Middle East and India saw more pronounced increases, with almost 6% and

[4] IEA estimates for regional hydrogen demand differ from other organisations like the China Hydrogen Alliance and the European Hydrogen Observatory due to different scopes for reporting demand. For example, the IEA does not include the use of residual gases from industrial processes (e.g. coke ovens and steam crackers) that contain hydrogen, in heat and electricity generation, whereas the China Hydrogen Alliance and the European Hydrogen Observatory do. See the annex for details on the methodology for reporting hydrogen demand in the Global Hydrogen Review.

over 4%, respectively, largely attributable to increasing use in refining and chemicals production, and in steel production, in the case of India.

Demand growth continues to be driven primarily by established industrial sectors, for products that use hydrogen as a feedstock, rather than by policies to promote low-emissions hydrogen[5] as a means to reduce emissions and enhance energy security. Demand remains concentrated in traditional uses: oil refining, chemical manufacturing (notably ammonia and methanol production), and steelmaking via the DRI process using fossil-derived synthesis gas. Demand in new applications increased less than in previous years, mostly driven by the use of hydrogen in biofuel production, but still accounts for less than 1% of hydrogen demand globally. In addition, nearly all of this demand was met by hydrogen produced from unabated fossil fuels (see Chapter 3 Hydrogen production).

Demand creation for low-emissions hydrogen

Demand for low-emissions hydrogen grew by nearly 10% in 2024 compared to 2023, driven primarily by greater use of hydrogen produced from renewable electricity in existing industrial processes and refining, particularly in China. Despite this, low-emissions hydrogen continues to represent less than 1% of total demand.

The higher cost of low-emissions hydrogen relative to hydrogen produced from unabated fossil fuels remains a significant barrier to broader adoption among existing hydrogen consumers. Similarly, the cost of using low-emissions hydrogen and hydrogen-based fuels in new applications where it can replace the use of fossil fuels is also higher than the use of incumbent fossil fuels or other clean energy technologies. This cost premium, combined with a limited range of commercially available end-use technologies (see Chapter 5 Investment and innovation), is constraining uptake in new applications.

In the absence of targeted policy interventions to narrow the cost gap and incentivise market participants to commit to low-emissions hydrogen, demand is likely to remain limited. While industrial sector engagement – such as through offtake agreements and procurement tenders – has gained momentum in recent years, emerging signs suggest that some of these private sector efforts may be losing traction.

[5] See annex for details on the definition of low-emissions hydrogen in the Global Hydrogen Review.

Hydrogen offtake agreements decline in volume and firmness amid slow market development

The total volume of hydrogen covered by offtake agreements reached more than 6 Mt at the end of 2024,[6] around one-quarter of which were firm offtakes.[7] However, after 3 consecutive years of growth, the volume included in agreements signed in 2024 declined to 1.7 Mtpa, from 2.4 Mtpa in 2023 (Figure 2.2). Agreements were also weaker: only around 20% of deals concluded in 2024 were firm agreements, compared to around 30% in 2023. In addition, some large preliminary agreements signed in previous years have been cancelled due to challenges with project development or the deprioritisation of hydrogen operations by some of the signing entities. More encouragingly, some previously announced preliminary agreements have become[8] or are close to becoming firm offtakes[9] that can help to unlock investments on the supply side in the near term.

The largest share of this decline was in offtake agreements for projects targeting international trade in hydrogen and hydrogen-based fuels without a disclosed end-use. These agreements are typically preliminary and non-binding in nature. This trend likely reflects the slower-than-anticipated development of global markets for low-emissions hydrogen and its derivatives, which has made it more difficult for potential buyers to commit to substantial offtake volumes.

Offtake agreements related to the use of hydrogen in established applications, such as ammonia production for chemical processes and refining decreased slightly. However, the share of firm agreements in these traditional sectors dropped significantly, from 65% in 2023 to just 20% in 2024. Nevertheless, in some cases, non-binding agreements have been sufficient to enable projects to reach financial close. For example, an AM Green (formerly Greenko) project in India secured preliminary offtake agreements totalling 850 ktpa of renewable ammonia with Yara, RWE and BASF, and was able to proceed to FID in the past year.

The total volume of hydrogen agreed in offtake deals for new applications – including steel, aviation, shipping and power generation – grew slightly in 2024, from 0.55 Mtpa to 0.7 Mtpa. However, the sectoral distribution of these agreements shifted: in 2023, aviation and shipping dominated the landscape, whereas in 2024, shipping was responsible for nearly half of the agreements, with steel and power being responsible for almost all of the remainder.

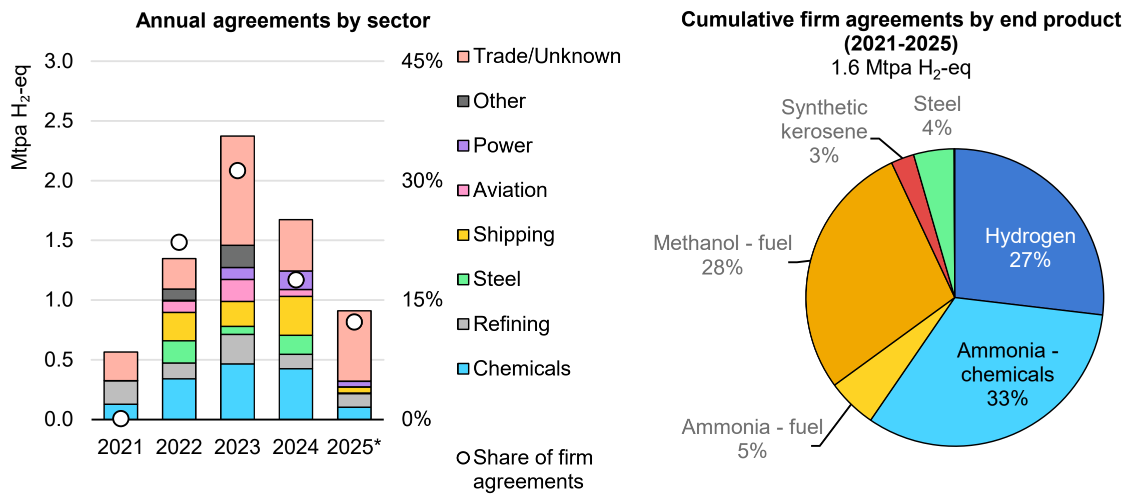
[6] This analysis excludes numerous small offtake agreements in the road transport sector, which together account for very small quantities at the global level. As a reference, global demand for hydrogen in the transport sector in 2024 reached around 100 kt (see Road transport section), mostly produced from unabated fossil fuels.

[7] Firm agreements include contractual arrangements with binding conditions for both suppliers and offtakers; preliminary agreements include other types of non-binding deals, such as Letters of Intent or memoranda of understanding (MoUs).

[8] Yara inks renewable ammonia offtake agreements with Indian producers at less than $680/mt: source, S&P Global (2025), Hydrogen Daily newsletter, 4 June.

[9] Atome, Yara target offtake agreement from Paraguay green fertilizer project in June, S&P Global (2025), Hydrogen Daily newsletter, 20 May.

Figure 2.2 Offtake agreements signed for low-emissions hydrogen and hydrogen-based products, 2021-2025



Notes: “Unknown” includes offtake agreements without a disclosed end-use for hydrogen and hydrogen-based fuels. “Other” includes road transport and industry applications other than chemicals and steel. Only offtake agreements disclosing the amount agreed and stating that they will take place before 2030 have been included. Firm offtake agreements are classed by the year in which they became firm. Cancelled agreements have been excluded. Announcements for hydrogen production and self-consumption are not included. 2025 data include agreements until July.

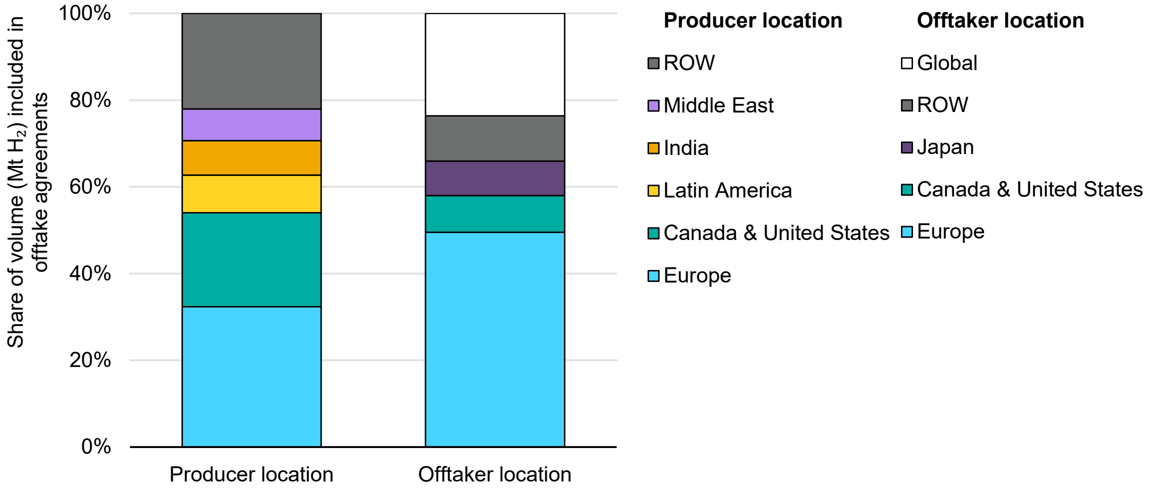
Sources: IEA analysis based on announcements of offtake agreements for hydrogen and hydrogen-based fuels and data from Argus Media Group, All rights reserved, BloombergNEF and S&P Global.

Offtake agreements for low-emissions hydrogen decreased in 2024, which could hinder investment in production projects.

The majority of firm offtakes are for the subsequent production of hydrogen-derived products, rather than the direct end-use of hydrogen (Figure 2.3). Offtakes of ammonia for chemical applications, such as fertiliser production, account for one-third of the firm offtake agreements, and the production of hydrogen-derived fuels (ammonia, methanol or synthetic kerosene) accounts for another third. This points to the potential for lead markets for hydrogen-derived end-use products to stimulate demand for low-emissions hydrogen (see The creation of lead markets).

In terms of regional distribution, offtake activity is concentrated in Europe (Figure 2.3), with around 50% of all volume included in agreements, followed by Japan with 8%. European offtakes are distributed across different sectors, with the largest deals coming from trade-oriented projects, and the chemical, steel and refining sectors, while Japanese offtakes are much more concentrated in the power sector. The producers involved in these agreements are more geographically diverse, with European producers accounting for around one-third of agreed volume, followed by the Canada and the United States with roughly one-fifth. Other regions with strong potential to produce low-emissions hydrogen, like Latin America, India, the Middle East, Africa and China, account for 5-10% of agreed volume, most of which is expected to be traded to major markets like Europe, Japan and Korea.

Figure 2.3 Regional distribution of cumulative offtake agreements, 2020-2025



Notes: ROW = Rest of world. “Global” refers to offtake agreements from companies that operate globally and for which a specific location for the offtake has not been identified. Data include agreements signed until July 2025.
Sources: IEA analysis based on announcements of offtake agreements for hydrogen and hydrogen-based fuels and data from Argus Media Group, All rights reserved, BloombergNEF and S&P Global.

European offtakers account for around half of the agreed volume included in offtake agreements, but only one-third of the agreed supply.

The creation of lead markets can kick-start demand creation

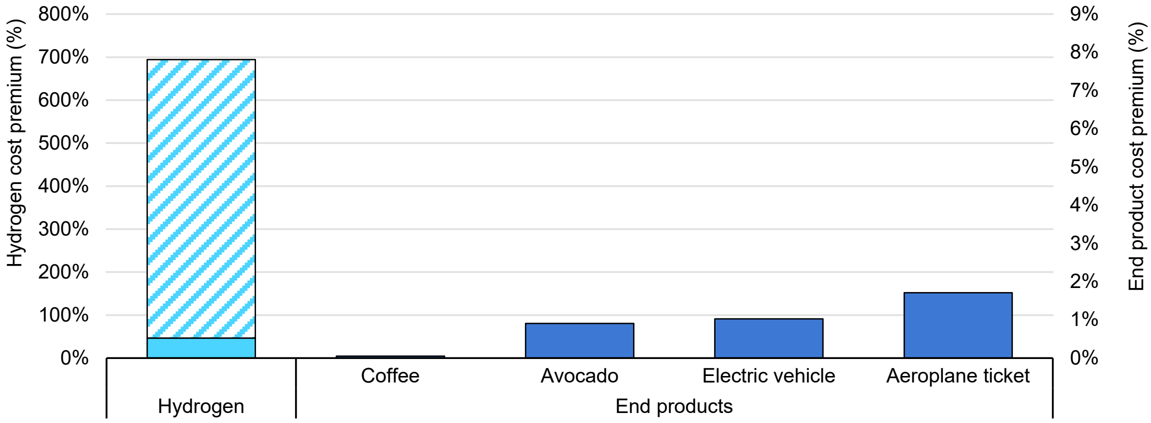
Depending on the location, renewable hydrogen can be between 1.5 and 7 times more expensive than unabated fossil hydrogen. This cost premium is an important challenge for project developers, but a wide range of final products use hydrogen as an intermediate feedstock, and in many cases the cost impact is likely to be manageable. The impact of using low-emissions intermediate products on the price of final products varies across sectors, but the premium decreases along the value chain, meaning that consumers see only a modest price increase in final products. The development of lead markets[10] therefore presents an opportunity to overcome these barriers and unlock demand for hydrogen. For example, using low-emissions fertilisers in the production of coffee would increase the cost of a cup of coffee in the United States by 0.05%, and using low-emissions ammonia in maritime transport would lead to a 0.9% increase in the cost of an avocado transported from Peru to China, over a distance of approximately 10 500 nautical miles. Similarly, the introduction of the ReFuelEU aviation quotas is expected to increase the cost of a flight ticket within the European Union by 1.7%, but only 1.4% of this increase comes from the use of synthetic fuels. Final industrial products also see a very moderate increase in cost when using low-emissions hydrogen in their production. The use of low-emissions steel (produced with

[10] A lead market is a country or region that pioneers the adoption and diffusion of products or technologies with a distinctive feature (e.g. environmentally friendly) that leads to a cost premium which prevents its adoption in traditional markets.

renewable hydrogen) in the production of electric vehicles (EVs) in the European Union increases the price of an EV by approximately 1% (Figure 2.4).

However, supply chains are complex and involve multiple intermediate actors who are likely to face additional challenges and require policy support to navigate the transition. Cost increases tend to be concentrated upstream in the supply chain, where producers operate with low price margins and competition is fierce. Producers in the middle of the chain often do not have visibility on the potential demand for their intermediate products from final consumers, and do not benefit directly from consumers' willingness to pay a higher price for those end products. For example, using renewable hydrogen in steel production leads to a cost premium of around 40% for the steel produced, which can be a major barrier for adoption in a sector that operates with very narrow margins.

Figure 2.4 Renewable hydrogen cost premium on selected end products



Notes: Profit margins are not included. Under "Coffee", average fertiliser use and yield for the United States is assumed, with a conventional ammonia price at USD 380/t and low-emissions ammonia price at USD 1 000/t, and a cup of coffee at USD 4. For "Avocado", assumptions include use of 100% of low-emissions ammonia as shipping fuel; heavy fuel oil price at USD 15/GJ and low-ammonia price at USD 50/GJ; maritime route of 10 500 nautical miles and a speed of 23.9 knots. For "Electric vehicle", assumptions include steel intensity of 820 kg/vehicle; price USD 40 000/vehicle. For "Aeroplane ticket", assumptions include the 2030 mandate of ReFuelEU for sustainable aviation fuels and e-fuels; fossil kerosene price at USD 28/GJ, bio-jet kerosene price at USD 35/GJ; and synthetic kerosene price at USD 163/GJ; fuel cost assumed to be 25% of the final ticket price. Detailed technoeconomic assumptions provided in the annex.

Sources: IEA analysis based on IEA (2023), The Role of E-fuels in Decarbonising Transport, REFuelEU, and data from UN Food and Agriculture Organization, Haifa, International Fertilizer Association, Bloomberg.

The low-emissions hydrogen cost premium is significant, but it translates into only small cost increases in end products.

A policy framework to create lead markets

The development of lead markets presents an opportunity to overcome these barriers and unlock demand for low-emissions hydrogen through early adopters who can drive the scale-up of hydrogen use. These markets can act as testing grounds, helping to demonstrate the viability and benefits of using low-emissions hydrogen. By creating an initial wave of demand, lead markets can help build momentum and encourage more businesses and industries to invest in hydrogen technologies. This early demand is essential for reducing the cost of production by enabling economies of scale, ultimately making hydrogen more affordable and accessible for a wider range of sectors.

Targeted policy action is required to overcome initial market challenges resulting from the small cost premium associated with the use of low-emissions hydrogen in the supply chain of final products. Some key policy instruments include:

- Demand-side policies: these include tax incentives linked to carbon intensity, quotas (as in the aviation sector), and public procurement programmes prioritising low-emissions materials and products.
- Carbon taxes: these can provide a strong economic signal to reduce carbon emissions, incentivising businesses to adopt cleaner technologies.
- Price support mechanisms: measures to help cover the cost premium include contracts for difference or product carbon premiums. Double-sided auctions, as used by the H2Global mechanism, promote competition on both sides of the market, ensuring greater price transparency and addressing the challenges of long-term offtake contracts.
- Certification and labelling: clear and reliable rules for measuring emissions and labelling products help consumers to trust low-emissions claims and help prevent greenwashing.
- Carbon border mechanisms: instruments like the EU Carbon Border Adjustment Mechanism (CBAM) aim to ensure that imported products comply with the same standards as those produced locally.
- Awareness and education: in addition to highlighting the environmental and social benefits of low-emissions products, it is important to raise awareness of concepts such as the "carbon footprint" of products to help consumers make informed decisions.

Policies that aim to foster lead markets must be carefully designed to balance industrial decarbonisation aims with affordability and equity considerations across sectors and regions. The product examples discussed above – coffee, EVs, avocados and aeroplane tickets – are all very different, and the public policy instruments required to distribute the cost premium across the value chain must take into account the varying implications for different consumer groups and industries.

The private sector also plays a role in the development of lead markets

The private sector has an important role to play in identifying areas in which such products are likely to gain traction among consumers, and which therefore present a market opportunity. There is already a pool of consumers willing to absorb small premiums for products that are sustainable and can offer additional benefits, as can be seen with the growing market for organic food in Europe, and in high-value sectors such as the automotive industry. The manufacturers of end products can act as anchor buyers for the low-emissions materials needed for their products by establishing long-term offtake commitments and de-risking the supply chain, thereby creating a knock-on effect that can trigger demand for intermediate products (including low-emissions hydrogen and its derivatives) and, therefore, investment in their production.

The establishment of initiatives based on transparent, measurable and verifiable demand-creation goals for different end products and co-ordination of stakeholders along the whole value chain can help achieve these aims. Private-led initiatives such as the First Movers Coalition and the Mission Possible Partnership have taken the first steps in this direction. However, despite positive first steps, the extent to which pledges made by such initiatives get implemented – and thus their real-world impact – remains to be seen.

Hydrogen procurement tenders yield mixed outcomes due to cost and infrastructure challenges

Several private sector actors have turned to hydrogen procurement tenders as a means to accelerate the adoption of low-emissions hydrogen, particularly in sectors in which emissions are hard to abate. The Global Hydrogen Review 2024 (GHR-24) highlighted the launch of six such initiatives in India and Europe that collectively targeted the procurement of nearly 1 Mtpa of low-emissions hydrogen. One year on, their outcomes have varied considerably, shaped by cost pressures, pricing mechanisms and infrastructure challenges (Table 2.1).

The most notable progress to date has come from TotalEnergies, which launched a tender in 2023 to procure renewable hydrogen for its refining operations across Europe. The company has already secured agreements covering 40% of its target of 500 ktpa, marking a significant step forward in advancing low-emissions hydrogen uptake in the refining sector. Since the release of the GHR-24, several state-owned refineries in India have launched six tenders for the supply of renewable hydrogen (Table 2.2).

In June 2024, the Solar Energy Corporation of India (SECI), a state-owned enterprise, issued a tender for the procurement of renewable ammonia (NH_3), to be supplied to 13 pre-selected fertiliser plants, to provide demand certainty. SECI evaluated the bids through a reverse auction process and awarded the contracts in August, at prices in the range of INR 49.75-64.74/kg NH_3 (Indian rupees) (~USD 580-750/t NH_3).

In Europe, three major steel producers – Salzgitter AG, Stahl-Holding-Saar and Thyssenkrupp Steel – launched tenders to secure hydrogen supply for their planned DRI plants. To date, none of these tenders have resulted in contract awards. Thyssenkrupp Steel, in particular, has temporarily suspended its tender process due to bid prices exceeding acceptable thresholds, a situation driven by elevated electrolyser costs and uncertainties surrounding renewable electricity pricing. Further delays in the development of hydrogen pipeline infrastructure have also impeded progress, requiring companies to adjust their project timelines.

Table 2.1 Tenders for procuring low-emissions hydrogen and hydrogen-based fuels and results as of May 2025

Company	Country	Sector	Capacity	Status (August 2025)
Salzgitter AG	Germany	Steel	Up to 141 ktpa of low-emissions hydrogen	Open; no contract awarded
Solar Energy Corporation of India	India	Fertilisers	724 ktpa of renewable ammonia*	Winning bids announced
Stahl-Holding-Saar	Germany	Steel	50 ktpa of renewable hydrogen	Open; no contract awarded
Thyssenkrupp Steel	Germany	Steel	143 ktpa of renewable hydrogen	Paused; no contract awarded
TotalEnergies	Belgium, France, Germany, the Netherlands	Refining	500 ktpa of renewable hydrogen	200 ktpa awarded; the rest is expected before the end of 2026
National Highways	United Kingdom	Construction	1.2 ktpa of low-emissions hydrogen	Open; companies shortlisted

* The size of the original tender was 539 ktpa, but this was later increased to 724 ktpa.

Emerging policy efforts are poised to drive uptake of low-emissions hydrogen in the near term

Despite the slowdown in efforts to adopt low-emissions hydrogen observed in 2024, several recent policy developments – which are expected to remain the primary driver of demand – suggest demand may improve in the near term. Notably, the IMO's Net-Zero Framework regulations, expected to be formally adopted in October 2025, could be a significant catalyst for the global uptake of clean fuels in the shipping sector, including hydrogen and hydrogen-derived fuels. However, some stakeholders have raised concerns that the current definition of IMO regulations may stimulate demand for other fuels (like LNG or biofuels) rather than hydrogen-based fuels in the short term (see Shipping for more details).

At the regional level, Europe continues to lead on policy-driven demand creation. This is reflected in mandates for the aviation sector introduced by the European Union (ReFuelEU Aviation) and the United Kingdom, Germany's Carbon Contracts for Difference scheme, and the ongoing transposition of the EU Renewable Energy Directive (RED) targets for transport and industry into national legislation (see Chapter 6: Policies). However, most EU member states have missed the original deadline of May 2025 for the transposition of these targets into national legislation. As of August 2025, only the Czech Republic and Romania (accounting for less than 5% of EU hydrogen demand) have adopted laws addressing both transport and industry RED targets for renewable fuels of non-biological origin (RFNBO) into their national legislation.

Other ambitious programmes that have been implemented since the GHR-2024 include Japan's Contracts for Difference scheme, Korea's Hydrogen Power Generation Bidding Market and the above-mentioned tenders for ammonia (in the fertiliser sector) and hydrogen (in refining) in India. On the other hand, the funding cuts for hydrogen projects announced by the US Department of Energy are likely to slow down the uptake of low-emissions hydrogen in the short term in the United States (see Chapter 6: Policies).

Demand in oil refining

Hydrogen demand in oil refining remains high, but growth is slowing, and adoption of low-emissions hydrogen is still limited

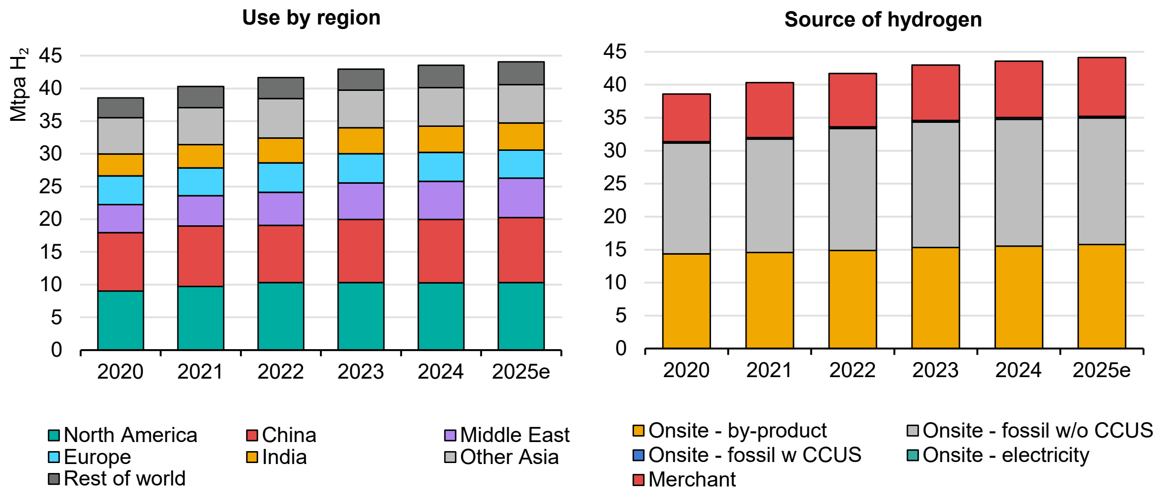
Oil refining is the sector with the second highest hydrogen demand after industry, exceeding 43 Mt in 2024 (Figure 2.5). However, demand growth in refining has slowed compared to previous years, with an increase of only about 0.5 Mt, nearly 40% of which originated from the Middle East.

As in previous years, most hydrogen consumed in refineries was produced onsite from unabated fossil fuels (45%) or as a by-product from other operations (35%), such as naphtha catalytic reforming. The remainder was merchant hydrogen,[11] which was also predominantly produced from unabated fossil fuels.

There was limited progress in adopting low-emissions hydrogen in refining in 2024, with use growing by just 3% to reach nearly 250 kt. This increase was mainly due to the ramp-up of projects that became partially operational in 2023 and the start-up of a project at the Szazhalombatta refinery in Hungary. Over 90% of the low-emissions hydrogen used in refineries today is produced from fossil fuels with carbon capture, utilisation, and storage (CCUS),[12] and is concentrated in a handful of projects in Canada and the United States, which mostly use the captured CO_2 in enhanced oil recovery.

[11] Merchant hydrogen refers to hydrogen that is purchased from external producers who then deliver hydrogen to the end users, normally by truck or using regional, privately owned hydrogen pipeline networks. In the case of refineries, merchant hydrogen is typically produced in plants located in proximity, and sometimes even in the same location, in plants operated by another company, given that hydrogen is not a global commodity today.
[12] See the Annex for details on the use of the terms CCUS, CCS and CCU in the Global Hydrogen Review.

Figure 2.5 Hydrogen use for refining by region and source of hydrogen, 2020-2025



Notes: Fossil w CCUS = fossil fuels with carbon capture, utilisation and storage; Fossil w/o CCUS = fossil fuels without CCUS. "Onsite" refers to the production of hydrogen inside refineries, including dedicated captive production and as a by-product of catalytic reformers. 2025e = estimate for 2025. The estimated value for 2025 is a projection based on trends observed until July 2025.

Hydrogen demand in oil refining reached its highest level yet in 2024, mostly produced onsite from unabated fossil fuels and as a by-product from other operations.

Box 2.1 The future of refineries

Oil refineries are a fundamental part of today's energy system, transforming crude oil into essential fuels and chemical feedstocks used every day across all economic sectors. Hydrogen plays a key role in refining operations as a feedstock, reagent and energy source for the transformation of crude oil into those products. Hydrogen is primarily used to hydrotreat products to remove impurities (especially sulphur) and in hydrocracking to upgrade heavier oil fractions into lighter products.

A complex short-term forecast

The IEA's Oil 2025 report showed that the refining sector is entering into a challenging phase. Demand for refined products is projected to peak in 2027 before declining, as accelerating drops in gasoline and diesel consumption outweigh growth in naphtha and jet fuel. In addition, the growing role of natural gas liquids in meeting petrochemical feedstock demand is eroding the market share of refineries in this sector.

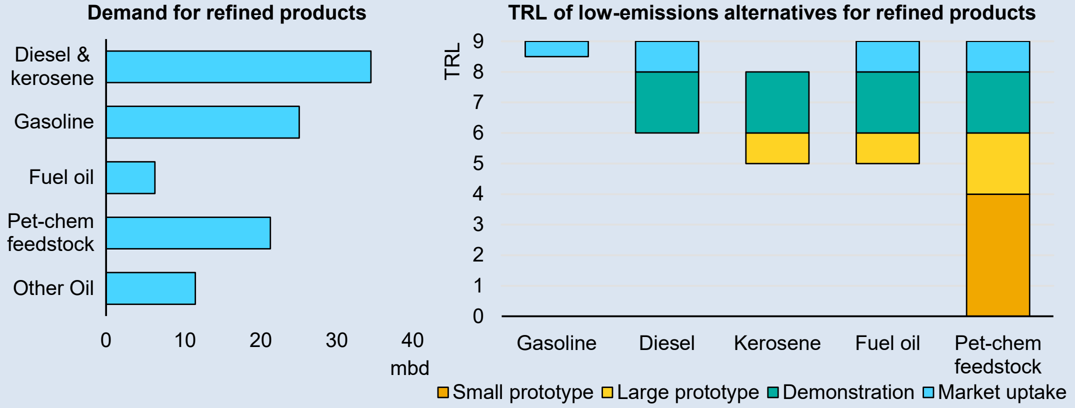
Despite tepid demand growth, global refining capacity is expected to increase by 2030, which will require refiners to either rationalise capacity or reduce utilisation rates. Regional trends differ, however: For example, refining capacity is projected to decrease in Europe from economic challenges associated with high energy costs and strict environmental regulations. Meanwhile, refining capacity is projected to expand in China, India and the Middle East due to factors like low energy and regulatory costs, rising domestic demands for petrochemical feedstocks and strategic positioning to export to growing Asian markets.

A vital sector despite growing challenges in the long term

A successful transition to a cleaner energy system means that several sectors shift to alternative technology, with impacts on the demand for oil products, particularly fuels. For example, further road transport electrification reduces demand for gasoline and diesel and the use of sustainable aviation fuels can decrease kerosene demand.

These challenges and uncertainties may lead to closures of some refineries, but transitions processes take time. In addition, modern refineries are multifaceted in that they produce more than just transportation fuels. Numerous products currently produced by refineries (such as petrochemical feedstocks, lubricants, asphalts and speciality products) appear to be difficult, or even impossible, to replace with low-emissions alternatives, either due to the high costs of alternatives or – first and foremost – to the lack of technological options for alternatives. Even in decarbonisation pathways, demand for these products is expected to remain resilient.

Demand for refined products, 2024, and technology readiness level of low-emissions technologies that could replace them



Notes: TRL = technology readiness level; Pet-chem = petrochemical. In the right-hand chart, alternative technologies for other oil products have been excluded since other oil products includes a very wide range of different products.
Source: ETP Clean Energy Technology Guide.

A potential future decline in the demand for refined oil fuels, at the same time as demand for refined oil products for non-energy uses remains stable, is likely to impact refinery operations, favouring refineries that are closely integrated with petrochemical plants. Demand for petrochemical feedstock is expected to grow substantially in the short term, prompting investment into integrated petrochemical complexes. This can have regional implications, as it already does today, given that most such facilities are based in Asia and the Middle East, and less so in Europe and North America.

A case for supporting low-emissions hydrogen in refining

Despite potential shifts in energy demand, the central role of refineries in the energy and chemical sectors is here to stay even under a fast energy transition.

However, many refineries are facing mounting challenges, particularly in advanced economies, and some are at risk of ending operations. More refineries may find themselves in this situation in the longer term. However, low-emissions fuels (biofuels, hydrogen and synthetic fuels) can provide an alternative to continue operations in many of these facilities. Refineries are well-placed to become supply centres for these fuels, making use of existing infrastructure as well as the expertise and skills in the sector, which can be critical to develop innovative, efficient and cost-effective solutions.

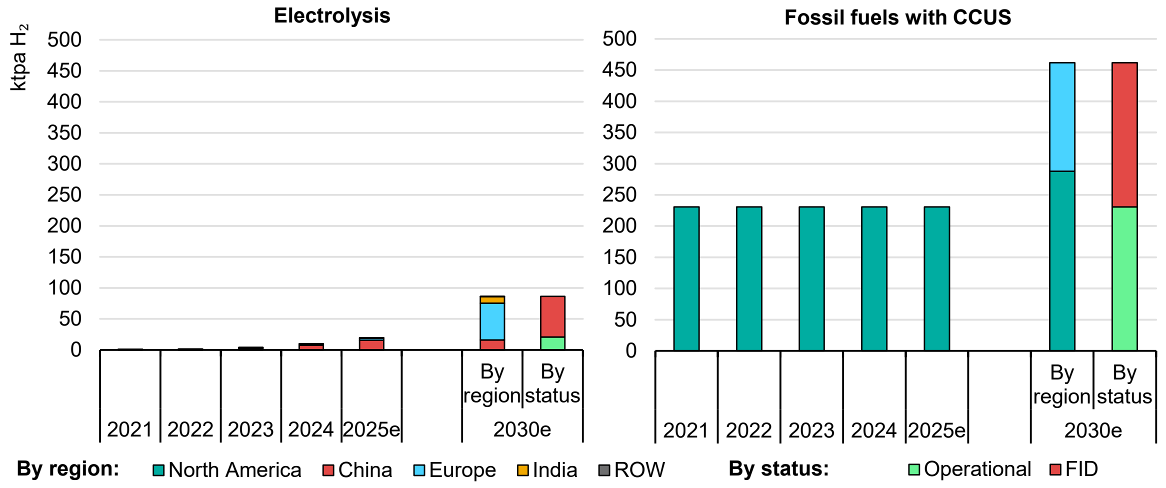
Additionally, a potential decline in demand for oil products does not necessarily imply a corresponding reduction in hydrogen use within refineries. Due to regulations requiring low-sulphur fuels, hydrogen consumption per unit of refinery output is expected to increase under energy transition scenarios.

There may also be a case for governments to work with refiners to chart a way forward in the interests of energy security, that can also be used to boost low-emissions hydrogen production and use. Australia, for example, is providing support to its last two refineries to stay open, in return for accelerated commitments to switch to producing low-sulphur fuels. This strategy could be replicated by governments elsewhere, supporting continued operation in refineries under the agreement to pursue an accelerated uptake for low-emissions hydrogen.

A growing pipeline of low-emissions hydrogen projects is emerging, with Europe leading new commitments

The short-term outlook for low-emissions hydrogen use in refining appears more promising. Considering only projects that have already reached FID, by 2030, production and use of low-emissions hydrogen in refineries for self-consumption could exceed 0.5 Mt – almost 15% more than last year's estimate (Figure 2.6). This increase is driven by nearly 100 kt of potential production from projects that reached FID in 2024 and 2025. The potential production from projects reaching FID in 2024 is half of that from projects reaching FID in 2023, when significant progress was made thanks to two large FIDs in the Netherlands (for hydrogen production from natural gas with CCUS linked to the Porthos project) and a 100 MW electrolysis project in Portugal.

Figure 2.6 Onsite production of low-emissions hydrogen for refining by technology and region from announced projects, 2021-2030



Notes: CCUS = carbon capture, utilisation and storage; FID = final investment decision; ROW = rest of world. “Onsite” refers to the production of hydrogen inside refineries, including dedicated captive production and as a by-product of catalytic reformers. 2025e = estimate for 2025. 2030e = estimate for 2030. The estimated values for 2025 and 2030 are based on projects that had reached FID by July 2025 with a target commercial operational date in 2025 and 2026-2030, respectively. Only projects that are operational, under construction of that reached FID are included.
Source: IEA Hydrogen Production Projects Database (September 2025).

More than 0.5 Mt of low-emissions hydrogen are expected to be produced and used in refineries by 2030.

In contrast, 2024 saw a larger number of projects reaching FID, but of smaller scale – a trend that has continued in the first half of 2025. The most significant developments have been in Europe (UpHy project in Austria and the Refhyne II and Lingen Green Hydrogen projects in Germany), but there was some progress in India (one project at the Panipat refinery) and Canada, with a project at the Scotford refinery (associated with the Polaris CCUS project).

Fossil-based hydrogen production with CCUS is expected to remain the main route for low-emissions hydrogen in refining in the near term. By 2030, hydrogen produced via electrolysis using low-emissions electricity is expected to be almost ten times larger than in 2024, but will only account for about 15% of all low-emissions hydrogen use.

Refining is the sector with the largest share of projects that have reached FID among announced projects, with one-third of potential production already at FID stage. If projects at earlier development stages (feasibility studies or concept phase) are also taken into account, an additional 0.7 Mt of low-emissions hydrogen could be used in refining by 2030 (1.2 Mt in total). These projects (together with projects that have reached FID or are operational) could meet the equivalent of nearly 3% of today’s global hydrogen demand in refining.

Supply from merchant low-emissions hydrogen projects could further increase this percentage. This avenue is being pursued by some oil and gas companies in order to secure low-emissions hydrogen supply for their refineries, particularly in Europe. As mentioned above, TotalEnergies has already contracted 200 ktpa of the 500 ktpa targeted by its tender launched in 2023 to procure low-emissions hydrogen for its European refineries, including large offtake agreements with Air Products (70 ktpa), RWE (30 ktpa), and Air Liquide (15 ktpa), as well as a joint venture with Air Liquide to build and operate a 250 MW electrolyser to supply 30 ktpa to its Zeeland refinery. The company plans to finalise agreements for the remaining 300 ktpa of its tender by the end of 2026. In addition, TotalEnergies and Air Liquide had already signed an offtake agreement for 15 ktpa prior the launch of the tender. Merchant supply allows refineries to minimise risks associated with onsite low-emissions hydrogen production, but it requires dedicated hydrogen infrastructure. In April 2025, Ontras completed the first conversion of a natural gas pipeline to hydrogen for refinery supply in Germany, but widespread infrastructure has not yet been developed, which could jeopardise this alternative supply route.

In India, several state-owned companies have launched tenders to secure the supply of merchant hydrogen to their refineries. These tenders have been launched in the form of Build-Own-Operate procurements, which imply that the companies with the awarded bids will be required to build a production plant, own, and operate it for the period of time stipulated in the tender. Successful commissioning of these tenders could lead to the use of more than 40 kt of merchant renewable hydrogen in India's refineries by 2030.

Table 2.2 Tenders for procuring merchant renewable hydrogen in refineries in India

Company	Refinery	Size (kt hydrogen)	Status (August 2025)
Indian Oil Corporation Limited	Panipat	10	Awarded to L&T Energy Green Tech with a bid of INR 397/kg H_2 (~USD 4.6/kg H_2), with the project already in FID
Bharat Petroleum Corporation Limited	Mumbai, Kochi or Bina	5	Awarded to Ocior Energy with a bid of INR 328/kg H_2 (~USD 3.8/kg H_2) for the Bina refinery
Hindustan Petroleum Corporation Limited	Visakh	5	Awarded to Ocior Energy with a bid of INR 328/kg H_2 (~USD 3.8/kg H_2)
Mangalore Refinery and Petrochemicals Limited	Mangalore	10	Bids submitted and under evaluation
Numaligarh Refinery Limited	Numaligarh	10	Bid submission deadline extended until August 2025
Chennai Petroleum Corporation	Tamil Nadu	2	Bids submitted and under evaluation

Source: IEA compilation based on data from corporate disclosures.

EU policy initiatives are driving demand for low-emissions hydrogen, though national implementation varies widely

Although North America currently accounts for over 90% of low-emissions hydrogen use in refining, Europe is expected to catch up by 2030. Today, Europe accounts for 75% of the FIDs for production projects in refining. Based on projects in operation and with FIDs, by 2030, Europe's share in the demand for low-emissions hydrogen could reach more than 45%, while North America's share could be reduced to 50%. This shift is largely due to EU policy measures. Although these policy efforts were initially intended to support decarbonisation goals, growing concerns about energy security and fossil fuel import dependency have contributed to renewed momentum behind the replacement of natural gas-based hydrogen use with renewable hydrogen.

The EU RED sets a target of 1% RFNBOs in transport fuels by 2030, including the use of renewable hydrogen to replace unabated fossil hydrogen in oil refining. This is expected to support the adoption of low-emissions hydrogen in refining in the near term, although only four EU member states have fully transposed the RED transport target into national legislation to date. The RED also gives member states flexibility in the measures they implement to meet the target, resulting in different policy approaches. As such, effectiveness in supporting low-emissions hydrogen adoption in refineries is likely to vary.

For example, the Czech Republic has included a mandatory 1% RFNBO quota in transport, with a non-compliance penalty of CZK 2/MJ (Czech koruny) (~USD 10/kg), allowing renewable hydrogen used as an intermediate product in refineries to count towards the obligation. Finland has set a 4% RFNBO quota in road transport with a non-compliance penalty of EUR 55/GJ, but renewable hydrogen used in refineries can only count for up to 1%. In response, Neste cancelled a 120 MW electrolysis project at its Porvoo refinery, arguing that this limitation reduced the project's economic viability. In the Netherlands, a GHG emission reduction quota of 1.07% for road transport and 0.32% for shipping to be met with RFNBOs by 2030 has been approved by the government.[13] An initial proposal to reduce renewable fuels credits by 60% if renewable hydrogen is used in refining, which could have impacted the viability of such projects, has been scrapped[14] (see Chapter 6: Policies).

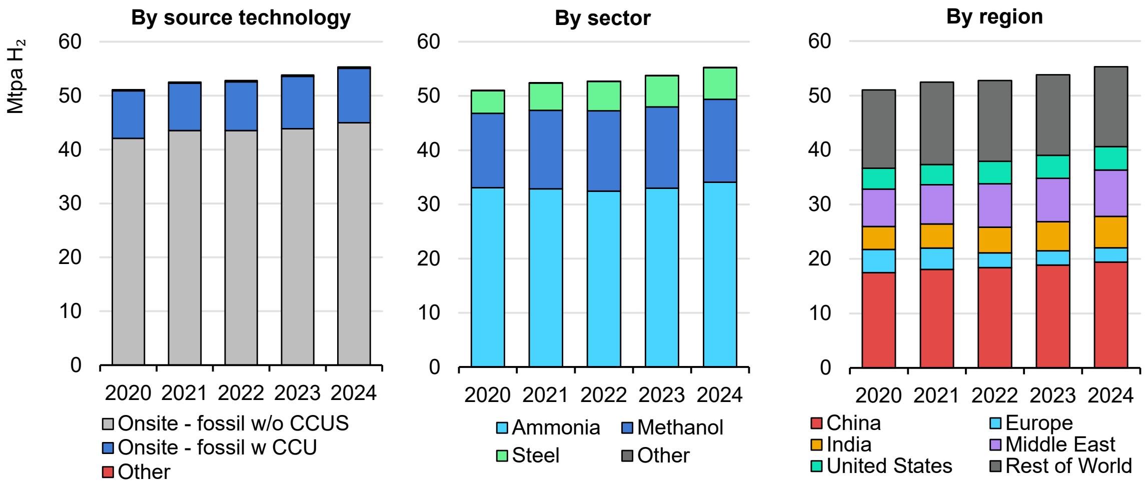
[13] The quotas have been included in a law that was submitted to parliament and is awaiting final approval.
[14] The proposal for the reduction credits has been scrapped at least until 2030 but may be re-introduced after then.

Demand in industry

Hydrogen demand growth in industry is accelerating

Global hydrogen demand in industry reached 55 Mt in 2024, an increase of almost 3% year-on-year (Figure 2.7). About 60% of this demand was for ammonia production, 30% for methanol and 10% for DRI in the iron and steel sector. The growth rate increased from 0.6% in 2022 and 2.0% in 2023.

Figure 2.7 Hydrogen use in industry by source technology, sector and region, 2020-2024



Notes: Fossil w/o CCUS = fossil fuels without carbon capture, utilisation and storage; Fossil w CCU = fossil fuels with carbon capture and use. In production by source technology, "Other" includes onsite production with bioenergy, carbon capture and storage or electricity, and merchant hydrogen. In demand by sector, "Other" includes dedicated hydrogen production for high-temperature heat applications.

Sources: IEA analysis based on data from Argus Media Group, All rights reserved, International Fertilizer Association, World Steel Association.

Growth in industrial hydrogen demand continued and even accelerated to 3%, comparable to the post-COVID rebound of 2021.

The majority of hydrogen used is produced within the same facility from unabated fossil fuels. Carbon capture is already a common practice in certain industries, although most of the 150 Mtpa of CO_2 captured is used for other industrial applications, such as urea production, and ends up being released to the atmosphere. As a result, hydrogen production in industry was responsible for around 705 Mt of direct CO_2 emissions in 2024, up 3% from 2023, and approximately equal to the total GHG emissions of Mexico.

Hydrogen use for ammonia had the highest growth rate, of 3.4%, followed by methanol, with 2.0%. China remains the largest user, with 35% of global industrial hydrogen use, followed by the Middle East (15%), India (10%), the United States (8%) and Europe (5%). Demand is currently growing fastest in the India and the

Middle East, with an increase of around 7% in 2024, with both locations building on their expertise to increase production of higher value-added chemical products like ammonia and methanol. In contrast, some European companies are now closing production facilities while infrastructure to import ammonia comes online. It therefore appears unlikely that Europe will return to its 2020 demand level of 4.2 Mt, compared to 2.6 Mt today.

The use of low-emissions hydrogen in industrial applications is moving towards maturity

Low-emissions hydrogen production in industrial plants in 2024 was about 320 kt, 85% of which was from fossil fuels with CCUS (Figure 2.8). Growth compared to 2023 was around 6%, with most of the additional capacity relying on electrolysis. Around 70% of capacity added in 2024 was located in China, 35% being for methanol production and 30% for ammonia. The number of projects in industry reached a new peak in 2024, with a dozen reaching operational status. Some noteworthy projects since GHR-24 include:

- Xingguo Precision Machinery (China) launched 300 000 m^3/day of electrolysis-based hydrogen for blending and use in blast furnace smelting.
- Xinjiang Dunhua (China) produces methanol with CCUS and captures 150 ktpa CO_2.
- In Cubatao (Brazil), Yara started production of ammonia from biomethane with a goal of producing 6-7 ktpa of ammonia.
- EMSTEEL (United Arab Emirates) successfully launched a demonstration project to produce low-emissions steel from hydrogen.

In 2025, production is expected to jump to 590 kt, mainly thanks to a large CCUS project from CF industries which started operation in their Donaldsonville facility (United States) in July, aiming to capture 2 Mtpa of CO_2 from ammonia production.

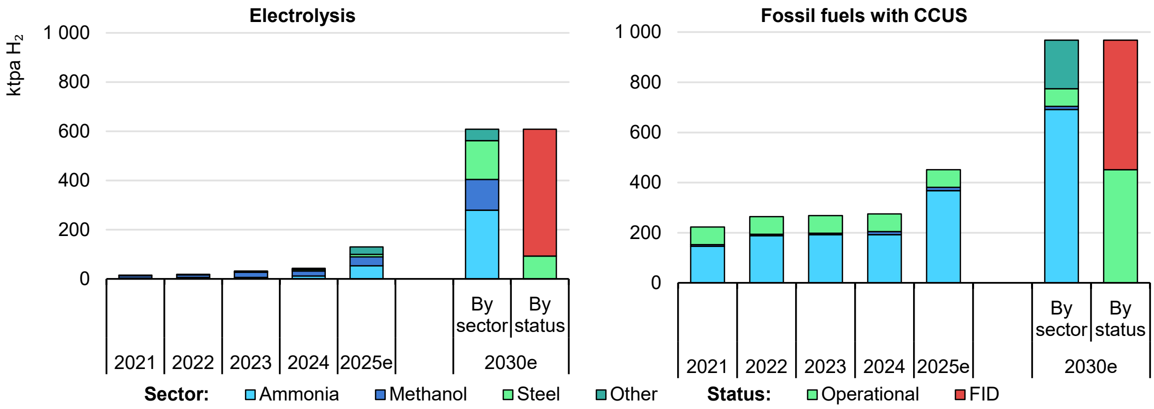
Considering all projects that are already under construction or that have reached FID, low-emissions hydrogen production in industry could reach 1 580 ktpa by 2030. Over 60% of those projects rely on CCUS, and almost two-thirds are aimed at ammonia production. In addition to methanol (9% of projects by 2030) and steel (14%), projects target numerous other applications, such as olefin, alumina, polysilicon or graphite production. Some of the most significant announcements of projects taking FID or starting construction since GHR-24 include:

- Envision Energy (China) commissioned the second phase of an electrolysis-based ammonia plant with a capacity of 300 ktpa NH_3, which is the world's largest operating electrolysis plant (500 MW).
- China General Nuclear started construction of a project with a production capacity of 400 ktpa of methanol from wind power in Inner Mongolia. The first phase, with

a production capacity of 200 ktpa of methanol, is expected to be operative by the end of 2025.

- JSW Energy (India) is setting up 25 MW of electrolyser capacity to manufacture near-zero emissions steel.
- Blue Point (United States) a joint venture between CF Industries, JERA and Mitsui to build a 1.4 Mt ammonia facility with carbon capture and storage (CCS) is expected to begin in 2029.

Figure 2.8 Onsite production of low-emissions hydrogen for industry applications by sector and by status, 2021-2030



Notes: CCUS = carbon capture, utilisation and storage; FID = final investment decision; 2025e, 2030e = estimate for 2025, and for 2030. The estimated values for 2025 and 2030 are based on projects that have reached FID by May 2025 with a target commercial operational date in 2025 and 2026-2030, respectively.
Source: IEA Hydrogen Production Projects Database (September 2025).

Major projects for the production and use of low-emissions hydrogen in industry are coming online in 2025, and additional growth is expected until 2030.

By 2030, over 95% of planned low-emissions hydrogen production in industry is expected to be located in North America (50%), China (25%), the European Union (15%), the Middle East (6%) and India (4%). However, production routes differ: Electrolysis is favoured in China, India and the European Union, while CCUS dominates in North America and the Middle East, reflecting their ample fossil fuel reserves. In terms of technology choice, alkaline electrolysers are the favoured option for electrolysis, and CCUS is mostly applied to ammonia production based on methane reforming (steam methane reforming [SMR] and autothermal reforming [ATR]) (see Chapter 3 Hydrogen production).

The competitiveness of hydrogen technologies

The cost of producing industrial materials such as ammonia, methanol and steel largely depends on three factors: the capital cost of the equipment, the cost of the energy inputs (fuels and electricity) and the cost of capital. The capital expenditures (CAPEX) for near-zero emissions facilities are often greater than for conventional ones. For steel H_2 DRI, upfront cost is expected to be 40-140% higher than for natural gas-based DRI once facilities reach commercial scale.[15] For ammonia production based on grid-connected electrolysis, the cost of the electrolysers alone accounts for 60-80% of the capital cost currently, for a total CAPEX up to double that of traditional unabated natural gas-based generation.[16] Nevertheless, energy costs often play a bigger role than CAPEX in the final production costs, meaning that a higher capital cost is not necessarily a barrier. Coal gasification for ammonia production is 55-90% more capital-intensive than SMR, but the technology is still widespread in China, where the lower cost for coal compared to natural gas offsets the higher capital costs. The strong impact of energy costs on the levelised cost of production of materials also leads to differences in the competitiveness of the different production routes across regions:

- **Steel:** Energy is one of the largest costs for steel manufacturers, alongside the iron ore input. The energy used takes the form of coal for blast furnaces, natural gas for DRI and electricity for H_2 DRI. The competitiveness of low-emissions routes depends on the incumbent unabated fossil-based technology that they replace. This depends on the existing production capacity, which varies across regions. DRI with CCUS technology generally yields the lowest cost gap with conventional DRI technologies, with regions like the Middle East and North America having a cost gap of 5% to 25%, due to access to cheap fossil fuel and domestic geological storage capacities. The cost gap is greater for H_2 DRI, ranging from 50% to 140% (depending on the region) when compared with blast furnaces, and 20% to 80% compared with unabated natural gas-based DRI.
- **Ammonia:** Across all production routes, energy is used to power the ammonia production, and the creation of hydrogen feedstock, be it through natural gas reforming, gasification or electrolysis. Energy is therefore the main cost driver for ammonia production. Low-emissions routes are currently more expensive than conventional routes in every region, particularly for electrolysis and CCUS technologies with high capture rates. In the European Union for instance, the cost gap is around 25% for CCUS and ranges around 120%-220% for electrolysis. However, the implementation of certain policies can be effective in closing this gap. The EU Emissions Trading System requires CO_2 emitters to pay a price for each tonne of CO_2 emitted. Fertiliser producers are eligible for free allowances that avoid or reduce CO_2 payments, but these free allowances will be gradually reduced as the CBAM enters in force. This could reduce the cost gap to as little as 5% for CCUS, and 75-160% for electrolysis, assuming a CO_2 cost of USD 100/t. The application of a CO_2 price in the region will help to level the playing field for low-emissions routes.

[15] The cost of the production process and of the eventual electrolyser and hydrogen storage are included in the CAPEX.
[16] This uncertainty range is the result of CAPEX variation between countries stemming from factors like cost of labour and cost of materials, as well as the inherent uncertainty related to a technology that is still improving.

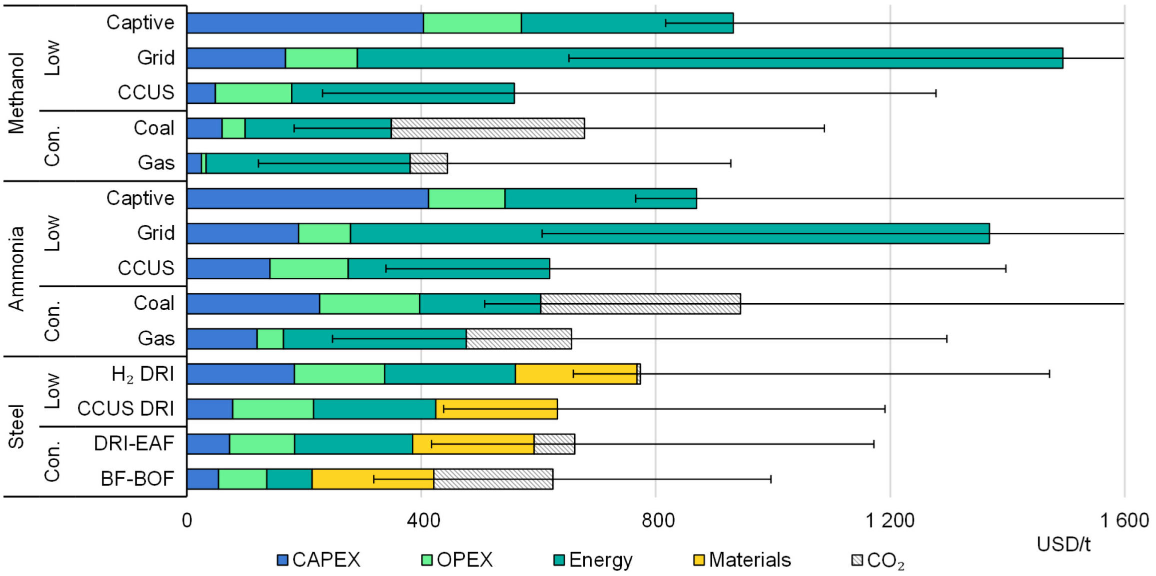
- **Methanol:** The factors affecting production cost are similar to those for ammonia. In the case of methanol produced using electrolysis, there is an additional complexity in finding a carbon source (normally captured CO_2). As a consequence of this, and the larger difference in CAPEX between conventional and hydrogen-based routes (compared to ammonia production), the cost gap for electrolytic methanol is greater than for ammonia or steel. India currently has the lowest cost gap (100%) between unabated natural gas-based production and electrolytic methanol, due to the high cost of imported natural gas. In the case of China, the world's largest producer of methanol, the price gap is around 70% for CCUS and 160% for electrolysis compared with unabated coal-based production, which is today's main production route in the country.

For electrolytic routes, electricity is often the main contributor to production costs (Figure 2.9). Price variation between regions can be significant, with the average industrial electricity price in Western Europe being USD 240/MWh compared to USD 80/MWh in the United States in 2023.[17] Even within a given region, price can vary greatly during the year or during the day.

Establishing an initial connection to the grid can take several years, and has already been a challenge for some advanced projects. As such, investing in captive renewable capacity can reduce uncertainty, and potentially also production costs, if conditions are favourable. The variability of renewables can be compensated with electricity from the grid at times of lower generation or onsite hydrogen storage, so the electrolyser operates following power output, while the main material production systems remain at nominal capacity. However, operating such storage capacity can be difficult (see Chapter 4 Hydrogen trade and infrastructure). Another alternative is to increase the flexibility of the process for the production of the final material (steel, ammonia or methanol). For example, some ammonia companies (such as Topsoe and KBR) are providing technologies that can already operate flexibly, even at as little as 10% of nominal capacity.

[17] Average end-user prices for grid-connected industries, including taxes and connection fees.

Figure 2.9 Levelised cost of production of selected materials by technology, 2024



Notes: Con. = Conventional; Low = Low-emissions; CCUS = carbon capture, utilisation and storage; DRI = direct reduced iron; EAF = electric arc furnace; BF = blast furnace; BOF = basic oxygen furnace; H_2 = hydrogen. Grid and Captive refer to electrolysis-based routes using either grid electricity or captive renewable production. CCUS refers to carbon capture and storage applied to natural gas. H_2 DRI uses captive power. The cost of the CO_2 input for methanol production and the cost of CO_2 transport and storage for CCUS are included in the OPEX category. CO_2 represents the cost increase if a USD 100/t CO_2 tax were in place. Error bars represent regional variation together with cost uncertainty for near-zero emissions technologies for material production. Energy costs are based on regional end-user prices for industry, including taxes and charges, and include fuel use for energy and for feedstock. The base case values and the ranges are as follows: USD 10/Mbtu for natural gas (USD 2.5-23/Mbtu); USD 100/t for coal (USD 17-200/t); USD 100/MWh for grid electricity (USD 30-300/MWh); USD 30/MWh for captive electricity (USD 20-50/MWh); USD 900/kW for electrolyser CAPEX in China and USD 2 300/kW elsewhere. Costs shown here do not include explicit financial support but may include financial support embedded in individual cost components (e.g. fossil fuel subsidies). See technical annex for further detail on technoeconomic assumptions.

Hydrogen technologies remain more expensive than conventional options, but CO_2 costs and regional characteristics can narrow the competitiveness gap in some cases.

Drivers of demand for low-emissions hydrogen in industry

Although the economics of using low-emissions hydrogen currently poses challenges, new projects are emerging and the project pipeline appears to be fairly robust. While most of these projects result from mature hydrogen demands in industry, such as ammonia or methanol production switching to low-emissions hydrogen, some are for more novel uses, such as steel production. Some of these use cases have recently become more mature, increasing the potential size of the market over the short to medium term, and stimulating demand (Figure 2.8).

More generally, projects are now emerging as a result of clearly communicated demand for lower-carbon commodities and products, such as through offtake agreements. For steel, offtake agreements amount to at least 2.2 Mtpa of steel produced using low-emissions hydrogen (with around 55% firm agreements), and another approximately 3 Mtpa of demand is covered by private sector demand aggregation initiatives for near-zero emissions steel. This amounts to a hydrogen demand of around 140 ktpa, rising to approximately 330 ktpa if it is used to produce the full 5 Mtpa of steel. For ammonia made with low-emissions hydrogen with a clear industrial end-use, offtake agreements account for 6.8 Mtpa (around 45% of which are firm agreements), which could correspond to a hydrogen demand of around 1.2 Mtpa. This potential hydrogen demand is similar to the 1.6 Mtpa of low-emissions hydrogen supply projects coming online by 2030 in industry.

Different factors on the supply side are also stimulating low-emissions hydrogen demand. Price rises and variability in fossil fuel markets over the last few years have increased prices and risks that need hedging or accounting for, and concerns around energy security have reduced the attractiveness of fossil fuel-based options in importing countries. In regions where electricity prices can be disconnected from fossil fuel prices and supply risks, electrolysis could become an attractive option for hydrogen supply. This may be through either onsite generation, power purchase agreements, or markets with low exposure to fossil fuels or price-setting. As an example, Quebec (Canada) has an almost 100% renewable grid, dominated by hydropower, and this low-cost electricity supply has historically attracted users such as aluminium producers (which is also an electrolytic process). Today, electrolytic ammonia projects are being developed in Quebec and other markets with similar characteristics.

Changes in the wider context and at the policy level also support a move away from incumbent options, such as India's policy on renewable hydrogen hubs, the EU RED (which includes a target to meet 42% of industrial demand for hydrogen with RFNBO), and China's Implementation Plan for Accelerating the Application of Clean and Low-Carbon Hydrogen in the Industrial Field (see Chapter 6: Policy). Policies continue to play a critical role in stimulating demand, through both explicit support and actions to remove barriers for low-emissions hydrogen.

Action underway to develop standards and labelling that can enable differentiation of lower-emission products can be especially important for industry, boosting demand and stimulating market formation. For ammonia, carbon intensity certification schemes from Ammonia Europe, The Fertiliser Institute, and the Ammonia Energy Association are being launched. Standards for steel include the Low Emissions Steel Standard, the ResponsibleSteel Standard, the Global Steel Climate Council (GSCC) Standard, and China Iron and Steel Association's Low Carbon Emission Steel Evaluation Method unveiled in October 2024. Market participants also price-in signals of potential future policies and anticipated future demand (such as national or company-level net zero targets), when making investment decisions, although these have less influence on supplier decision-making than the current market and policy environment.

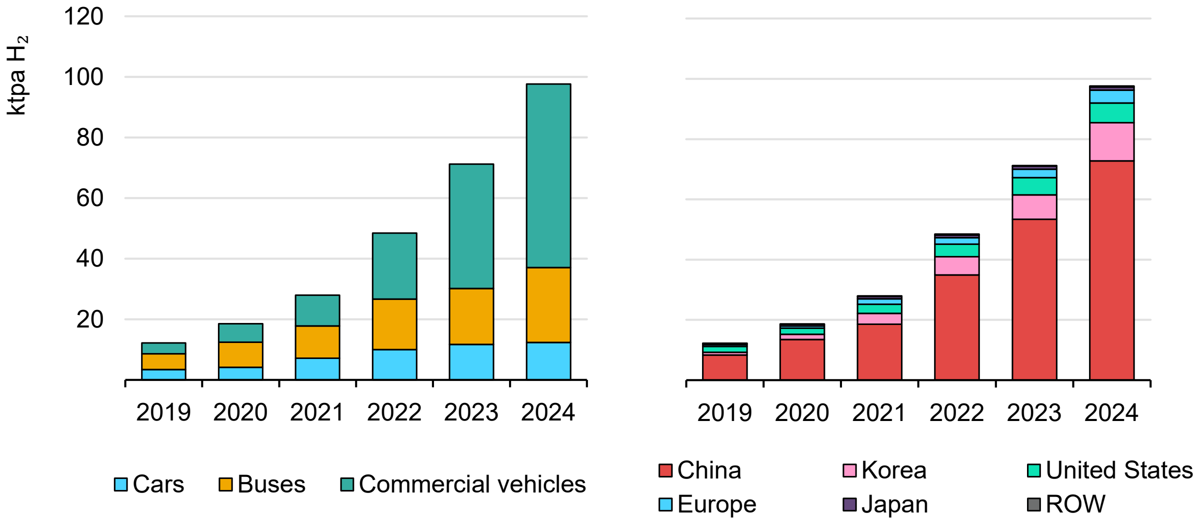
Demand in transport

Road transport

Heavy-duty vehicles are behind growth in hydrogen use in road transport

In 2024, hydrogen demand for road transport grew almost 40% year-on-year to reach around 100 kt (Figure 2.10). Despite this significant increase, the road transport sector remains a minor and emerging contributor to global hydrogen demand, accounting for roughly 0.1% of total consumption.

Figure 2.10 Hydrogen demand in road transport by vehicle mode and region, 2019-2024



Notes: ROW = Rest of World. Commercial vehicles include light commercial vehicles and medium- and heavy-duty trucks. Assumptions on annual mileage and fuel economy come from the IEA Global Energy and Climate Model.

Hydrogen demand in road transport increased nearly 40% in 2024, largely as a result of growth in demand for trucks in China.

This increase was primarily driven by growth in demand for heavy-duty trucks, particularly in China. Although trucks made up only 15% of the global stock of hydrogen-fuelled vehicles in 2024, or about 15 500 fuel cell trucks, they accounted for nearly two-thirds of hydrogen consumption in the sector, as they cover greater distances and have higher energy demands per kilometre than other road transport modes. The single largest share of demand was for heavy-duty trucks in China, which accounted for more than half of road transport hydrogen use globally. Buses accounted for about one-quarter, and although they make up 70% of the hydrogen vehicle fleet, passenger cars accounted for only around 10% of hydrogen use in the sector, due to their lower energy intensity compared to heavier commercial vehicles.

Hydrogen demand in the road transport sector remains concentrated in a few countries. In 2024, China accounted for 75% of global demand, followed by Korea with almost 15%, and the United States representing more than 5% of the total. Emerging use of hydrogen-fuelled heavy-duty trucks in Europe meant hydrogen demand for transport in the region grew by over 50%, bringing its share of the total close to 5%.

Sales of fuel cell electric vehicles are strongest for commercial vehicles

Less than 5 000 fuel cell car sales were reported worldwide in 2024, continuing a decreasing trend in annual sales (Figure 2.11). This trend is most noticeable in the United States and Korea, which have the largest stocks of fuel cell cars. In Korea, less than 3 000 fuel cell cars were sold in 2024, about 40% less than in 2023 and 75% less than in 2022. Despite this downturn, Korea's largest carmaker, Hyundai, is still committed to its fuel cell electric vehicle (FCEV) deployment strategy. In 2024, the company announced the successor to its only fuel cell car model, the Hyundai Nexo, featuring an extended range of 700 km. The Nexo production will be supported by in a new domestic fuel cell manufacturing plant set to break ground in 2028, with an annual output capacity of 6 500 units. In the United States, Toyota cleared stock by reducing the price of its hydrogen fuel cell model by up to 70% at the start of 2024, in addition to offering USD 15 000 worth of hydrogen to potential buyers.

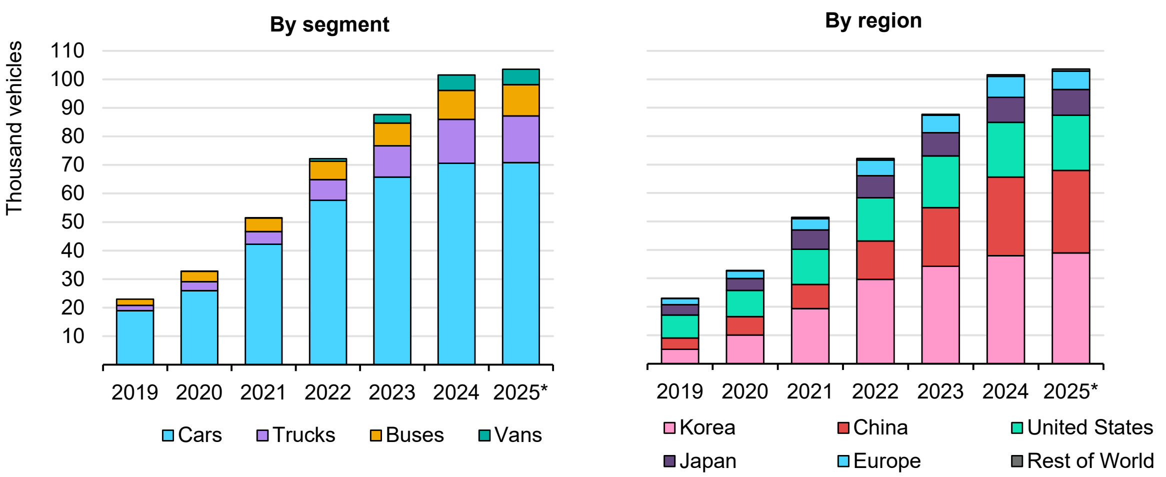
While only a handful of original equipment manufacturers produce fuel cell cars, Chinese carmakers, such as FAW and SAIC, have added fuel cell car models to their line-ups in recent years. Nevertheless, fuel cell car sales in China decreased to less than 100 units in 2024, down from about 500 units the year before.

In contrast, the stock of fuel cell trucks in China increased 40% in 2024 compared with 2023, reaching almost 15 000 vehicles, about 5 times the number at the end of 2020. Yet the number of fuel cell trucks on Chinese roads still pales in comparison to other alternative powertrain technologies and, even when other road vehicle types are included, the 2024 FCEV stock falls short of the 50 000 target set for the end of 2025. In 2024, there were around 25 times as many battery electric trucks and about 65 times as many compressed natural gas trucks as hydrogen-fuelled trucks operating in the country. In addition, the stock of fuel cell light commercial vehicles (LCVs) in China reached more than 5 000 by the end of 2024, nearly double that of the previous year. Almost 95% of the world's fuel cell commercial vehicles (including LCVs, medium- and heavy-duty trucks) are in China, where they make up more than 70% of the country's FCEV stock. The higher total cost of ownership of fuel cell electric trucks compared to their battery electric equivalents (see However, there were also some setbacks; in Austria, for example, the country's sole operator of HRSs, OMV, announced that it will close all stations by September 2025 due to poor market uptake and operating financial losses. The United States and Japan have also seen the number of available

HRSs fluctuate over the past year or so, as hydrogen supply and station reliability issues have led to temporary and permanent closures. The number of operational stations in the United States increased in 2024, but remains below the number available between 2017 and 2022. In California, in particular, the number of HRSs declined year-on-year as Shell and other operators permanently closed their stations, making the state's goal of deploying 200 HRSs by the end of 2025 increasingly unlikely. In Japan, the number of available HRSs fell for the second consecutive year in 2025, dropping to about 160 operational stations, the lowest total since 2020. This decline was due to the closure of small- to medium-sized facilities as the focus shifted towards expanding larger HRSs across the country.

Fuel cell long-haul trucks require major cost reductions to compete with their battery electric counterparts) suggest that their recent adoption in China is most likely a result of recent policies. In 2020, the Chinese government issued several pilot policies to support the use of hydrogen in the road transport sector within three key city clusters (Beijing, Shanghai and Guangdong). In 2022, two more clusters (Henan and Hebei) were added, bringing the programme's coverage to a total of over 50 cities. Running from 2022 to 2025, these pilots grant purchase subsidies and financial credits to cities, fleet operators and hydrogen refuelling station operators based on their achievement of predefined targets. By April 2025, the five clusters had already received RMB 5.1 billion (USD 710 million), 60% of the total budget envelope. This policy framework underpins the emergence of a network to support hydrogen use in road transport in China and also supports the country's goal of reaching 1 million FCEVs on the road by 2035, as set by the New Energy Vehicle Industrial Development Plan for 2021 to 2035.

Figure 2.11 Fuel cell electric vehicle stock by segment and region, 2019-2025



Note: 2025* includes data from January to July.

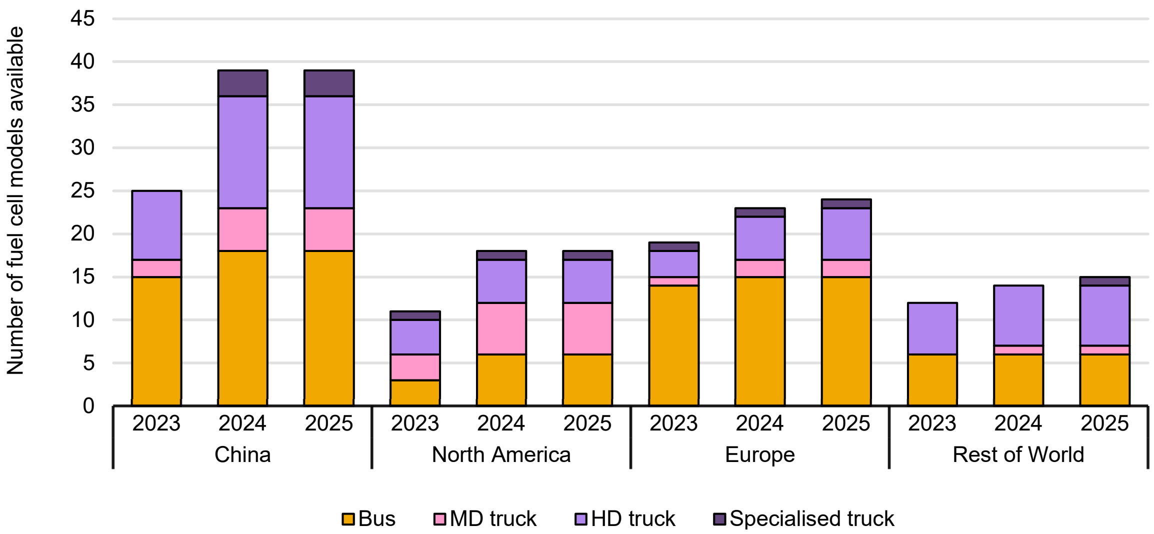
Sources: IEA (2025), Global EV Outlook 2025, EAFO (European Alternative Fuels Observatory), H2FCP (Hydrogen Fuel Cell Partnership), JADA (Japan Automobile Dealers Association), EV Volumes and Clean Energy Ministerial Hydrogen Initiative country survey responses.

Fuel cell car sales growth continues to slow down globally, though China is driving a surge in fuel cell commercial vehicle sales.

Some 50 fuel cell commercial vehicle models were available worldwide in 2024, about 10 times fewer than battery electric models. Of these, more than 60% were heavy-duty truck models, from around 20 different manufacturers (Figure 2.12). Nevertheless, there are signs that the market remains difficult, with several truck manufacturers facing bankruptcy or insolvency proceedings (see Chapter 5 Investment and innovation). The fuel cell LCV industry is also suffering major setbacks in Europe. In February 2025, the joint venture between Renault and Plug Power was put into liquidation. In July 2025, Stellantis announced it was abandoning its fuel cell technology development programme, ending the production of its fuel cell van models; France's largest fuel cell producer, Symbio, lost its main partner as a result.

The global stock of fuel cell buses grew by around 25% in 2024. Of this, almost 75% are in China, and more than 15% in Korea, where the stock grew strongly in 2024 to reach 1 700. The Korean government is seeking to increase the country's hydrogen bus fleet more than tenfold by 2030, to gradually replace conventional options. To drive uptake, fuel subsidies for fuel cell bus operators were raised to KRW 5 000 (Korean won) per kg H_2 (equivalent to USD 3.7/kg H_2 with 2024 conversion rates).

Figure 2.12 Fuel cell electric heavy-duty vehicle models by original equipment manufacturer origin, vehicle mode and release date, 2023-2025



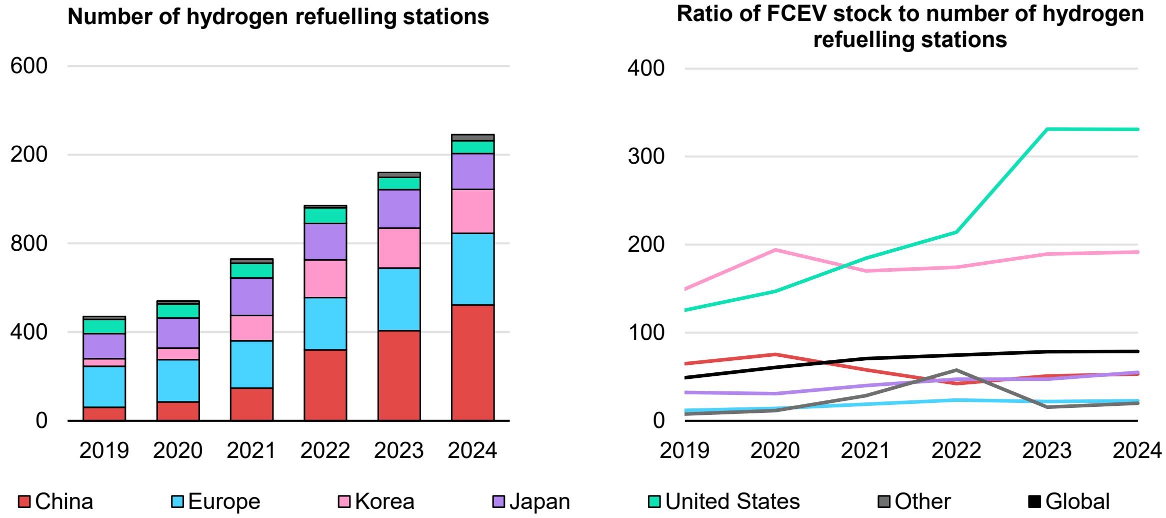
Notes: MD = medium-duty; HD = heavy-duty. This figure is based on a continually updated inventory and may not be fully comprehensive due to new model announcements and small manufacturers not yet captured in the database. Values for 2023 include models released between 2016 and 2023 inclusive. The database contains coaches, school buses, shuttle buses, and transit buses, categorised here as "Bus", which refers to those with more than 25 seats. "MD truck" includes medium-duty (MD) trucks, MD step vans, and cargo vans with a gross vehicle weight (GVW) of greater than 3.5 t but less than 15 t. "HD truck" includes all freight trucks with a GVW of greater than 15 t. "Specialised truck" includes garbage trucks, concrete mixers, and other specialised mobile commercial trucks. Buses with 25 seats or fewer and light commercial vehicles that have a GVW of less than 3.5 t are excluded from this analysis. Vehicles of the same model that appear more than once in the database, but with small variations in specifications, such as power, payload or seating, are counted as one model.
Source: IEA analysis based on the Global Drive to Zero ZETI tool database.

Buses account for the largest share of available fuel cell heavy-duty vehicle models globally but fuel cell heavy-duty truck models gained ground in 2024.

Number of hydrogen refuelling stations continues to grow, despite setbacks

At the end of 2024, there were around 1 300 hydrogen refuelling stations (HRSs) in operation worldwide, 15% more than at the end of 2023 (Figure 2.13). The biggest increase was in China, where the number of stations increased 30% to over 500. In Europe, there were more than 300 stations at the end of 2024, 15% more than 2023, but still below the 2030 goal to deploy one HRS every 200 km along the TEN-T core road network, and one HRS in all the 337 urban nodes selected by the EU Alternative Fuel Infrastructure Regulation.

Figure 2.13 Number of hydrogen refuelling stations by region and ratio of fuel cell electric vehicle stock to number of stations, 2019-2024



Note: FCEV = fuel cell electric vehicle.
Source: IEA (2025), Global Electric Vehicle Outlook 2025.

China leads the global roll-out of hydrogen refuelling stations, whereas station availability has declined in the United States, due to reliability and hydrogen supply issues.

However, there were also some setbacks; in Austria, for example, the country's sole operator of HRSs, OMV, announced that it will close all stations by September 2025 due to poor market uptake and operating financial losses. The United States and Japan have also seen the number of available HRSs fluctuate over the past year or so, as hydrogen supply and station reliability issues have led to temporary and permanent closures. The number of operational stations in the United States increased in 2024, but remains below the number available between 2017 and 2022. In California, in particular, the number of HRSs declined year-on-year as Shell and other operators permanently closed their stations, making the state's goal of deploying 200 HRSs by the end of 2025 increasingly unlikely. In Japan, the number of available HRSs fell for the second consecutive year in 2025, dropping to about 160 operational stations, the lowest total since 2020. This decline was due to the closure of small- to medium-sized facilities as the focus shifted towards expanding larger HRSs across the country.

Fuel cell long-haul trucks require major cost reductions to compete with their battery electric counterparts

Commercial vehicle owners and operators are typically very sensitive to the total cost of ownership (TCO) of zero-emissions trucks, such as fuel cell or battery electric long-haul trucks, when compared with their traditional diesel counterparts. TCO is therefore one of the key factors determining adoption. In analysis published in the IEA's Global EV Outlook 2025, we show that the TCO after 5 years of operation of a 500-km range battery electric heavy-duty truck (BET) acquired in 2024 is already lower than for a diesel equivalent in China in certain cases – but the TCO of an equivalent hydrogen fuel cell electric truck (FCET) remained about 35% higher.

In Europe and the United States, both BETs and FCETs currently have a higher TCO than diesel equivalents in an identical use case. For BETs, the TCO is on average 15-20% higher, and for FCETs, 50% higher. However, the specific application and use profile of trucks are key factors for determining which powertrain technology is most suitable and whether FCET can complement BET as an alternative to diesel, meaning case-by-case analysis may be needed to evaluate the costs of various alternatives.

FCETs face significant cost hurdles due to fuel and necessary infrastructure. Fuel costs account for up to 35% of their TCO (excluding driver costs), and hydrogen refuelling infrastructure adds another 10-20%, depending on the region. While FCETs are about 30% more energy-efficient than diesel trucks in relative terms, they lag behind BETs, which are 55% more efficient on identical mission profiles. Hydrogen fuel remains expensive, due to high costs for both production and for HRSs, especially when utilisation rates are low. Hydrogen fuel prices at the pump vary hugely by region; for example, in March 2025, S&P Global Platts reported average hydrogen pump prices at USD 6.3, USD 14.6 and USD 34.3 per kilogramme in China, Germany and California, respectively.[18] These prices were between 2 and 6.5 times more expensive than electricity per unit of energy. When compared to diesel, these reported hydrogen prices more than 2 times more expensive per unit of energy in China and Germany, respectively, while in California hydrogen pump prices were about 10 times those of diesel. HRSs are more costly to build than EV chargers but can support more trucks daily without adding as much stress for the electrical grid. With 2024 assumed fuel price levels,

[18] For the TCO analysis presented in this report, different hydrogen prices have been used, based on production costs to avoid distortions from market equilibrium and subsidies. See annex for methodological details.

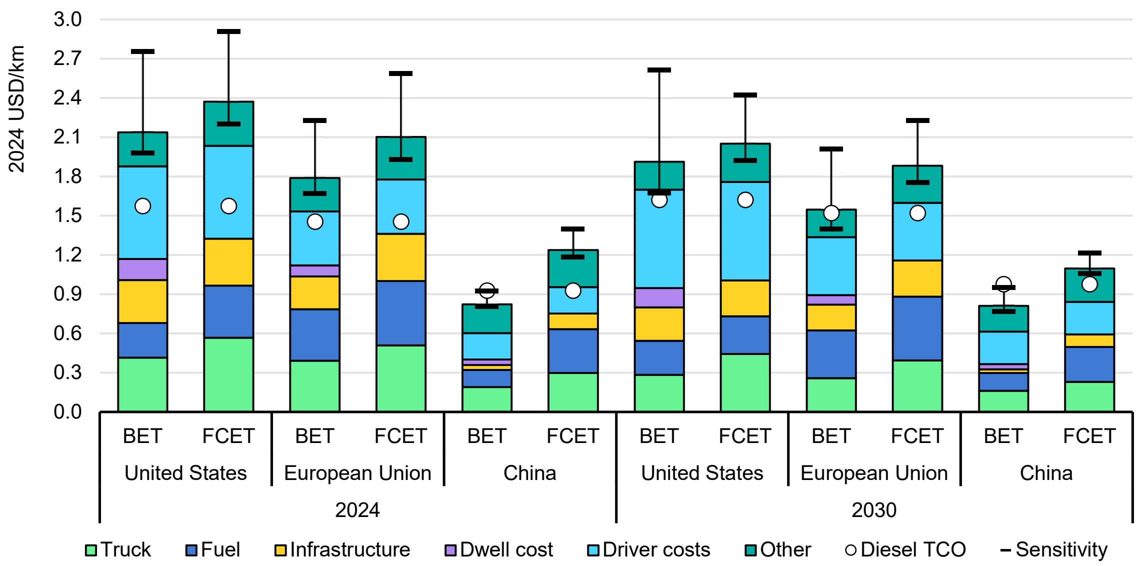
boosting HRS utilisation from 30% to 80% can cut infrastructure-related hydrogen costs by nearly 60%, reducing overall hydrogen fuel costs per kilometre by 25%. However, even under such optimal conditions, fuel cell trucks still end up being more expensive than their battery electric equivalents – about 5% more when a little-utilised EV charger is considered for BETs, and twice as expensive in the case of a BET served by a highly utilised EV charger.

The manufacturing costs of batteries, fuel cells, and hydrogen storage tanks are expected to decline thanks to greater economies of scale and technology improvements, driving down the capital costs of both battery electric and fuel cell trucks. However, although the purchase price of a FCET is likely to fall 20-25% in the next 5 years, they are expected to remain more expensive than both battery electric and diesel trucks at the point of purchase. By 2030, resulting capital costs, together with higher fuel costs, mean that a 500-km range FCET remains more costly to own than a diesel truck, while equivalent BETs are set to reach TCO parity by 2030 in the three major regions analysed.

Longer-haul applications could improve the competitiveness of FCETs with their battery electric equivalents, for three key reasons. First, the capital costs associated with BETs could rise significantly if larger batteries are required to extend their range. Second, a larger battery would lead to a significant powertrain weight increase, reducing the truck's payload capacity. Third, if the battery size remains unchanged despite longer daily driving distances, drivers must spend more time charging to complete their daily routes, leading to higher dwell time costs. To determine whether such a use case could negate the TCO advantage of BETs over FCETs, Figure 2.14 shows a comparison of the TCO based on a mission profile with a daily driving distance of 800 km. Such long-distance routes may be uncommon in some regions, but are more typical in others. In China, more than 95% of road freight activity hinges on daily trips shorter than 500 km. In the European Union, only 25% of long-haul trips exceed 500 km per day and less than 3% go beyond 800 km. On the other hand, population density, geographic scale and longer permitted driving hours all increase the average daily distance of long-haul applications in the United States. In 2023, although not necessarily completed in a single day, about 40% of US road freight activity was tied to routes longer than 800 km.

By 2030, in the 800-km daily route scenario, the TCO gaps between FCETs and diesel and battery electric trucks narrow, but remain in place across all analysed regions. However, in China in 2030, optimistic assumptions for FCETs (low-cost in the sensitivity analysis) bring the TCO of FCETs within less than 15% of that for diesel trucks. Importantly, BETs still offer a lower TCO than diesel trucks in this case, even if costs are high in the sensitivity analysis.

Figure 2.14 Total cost of ownership for battery electric and hydrogen fuel cell heavy-duty trucks operating an 800-km daily haulage in selected regions, 2024-2030



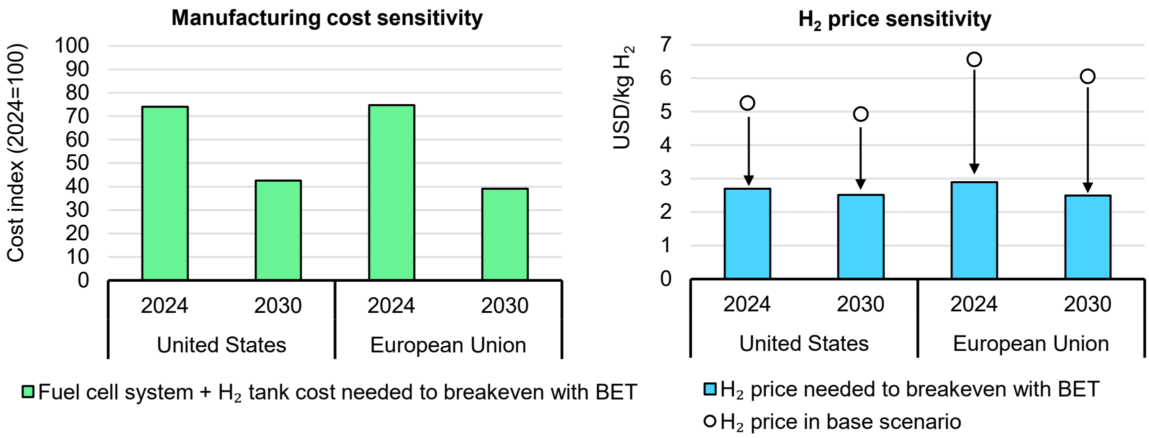
Notes: TCO = total cost of ownership; FCET = fuel cell electric truck; BET = battery electric truck. "Truck" refers to the cost of the truck including financing over 5 years at 5% interest and the residual value in year 5. "Infrastructure" is the levelised contribution to the cost of the EV charging or hydrogen refuelling station. "Driver costs" is the cost of employing a truck driver during normal working. "Dwell cost" is the additional cost incurred when a driver must continue charging beyond their rest period. "Other" costs include insurance and maintenance. Cost projections are based on the 2024 Global Energy and Climate Model Stated Policies Scenario in the IEA's World Energy Outlook 2024 report. See the annex for a full list of sources, assumptions, and other inputs. An 800-km daily route was considered in this analysis, as opposed to the 500-km daily routes assumed in GEVO-25 analysis. The battery size of the battery electric truck used for comparison remains unchanged from GEVO-25 analysis, and such trucks need to stop twice a day to complete the 800-km mission profile. The hydrogen tank capacity of the considered fuel cell truck has been increased from 60 kg to 80 kg to cover the longer daily route.
Source: Based on IEA (2025), Global Electric Vehicle Outlook 2025.

By 2030, differences in TCO between fuel cell and battery electric trucks operating an 800-km daily route narrow, but do not disappear.

In 2024 and 2030, the TCO of FCETs in the base case is lower than that of BETs recharged at under-utilised charging points (high cost in the sensitivity analysis) in both the European Union and the United States. In 2024, in the base case scenario, a hydrogen price around USD 2.8/kg H_2 is required for FCETs to reach TCO parity with BETs in both the latter regions, all else being equal (Figure 2.15). In China, in both 2024 and 2030, low charging infrastructure costs and low electricity prices for BETs would make it impossible to reach TCO parity between the two technologies by lowering the hydrogen price.

This comparative TCO study does not include potential electricity grid upgrade costs, which can vary significantly by region depending on local grid readiness and the level of infrastructure required (distribution lines, substations, breakers, transformers, switchgear, etc.). While a 350-kW charger is assumed for opportunity charging in this TCO comparative analysis, electric truck fleet operators could also opt for megawatt charging solutions to speed up recharging times. Such high-power charging technologies could place higher pressure on the grid and may consequently require costlier hardware upgrades. Factoring in grid upgrade costs could more than double the total infrastructure costs in the case of a megawatt charging station located in a remote rural area, while those located in urban areas that are closer to existing substations may only require less than 30% increase in total investment. In the current analysis, the doubling the infrastructure cost would translate into a hike of about 10% in the TCO of the 800km-range BET in both the European Union and the United States and an increase of about 2% in China. In the European Union, lengthy permitting and grid connection procedures pose a greater hurdle for charging point operators than the cost of rolling out the charging infrastructure itself, as highlighted by a European Commission communication in June 2025.

Figure 2.15 Breakeven hydrogen price, fuel cell system and hydrogen tank manufacturing costs needed to reach total cost of ownership parity with battery electric trucks in selected regions, 2024-2030



IEA. CC BY 4.0.

Notes: H_2 = hydrogen; BET = battery electric truck. In 2024, the manufacturing costs of the fuel cell system are USD 330/kW and USD 365/kW in the European Union and the United States, respectively. Those of the hydrogen tank system are USD 910/kg H_2 and USD 1 010/kg H_2. In the left-hand side figure, manufacturing costs of the fuel cell system and hydrogen tanks are scaled down evenly (all else being equal) in the base case scenario, with a constant hydrogen price of USD 4/kg H_2 across all regions and timeframes. The hydrogen price represents the price paid by the hydrogen refuelling station operator; as such, hydrogen price shown is exclusive of infrastructure cost. In the right-hand side figure, the hydrogen price is varied, all else being equal in the base case scenario.
Source: Based on IEA (2025), Global EV Outlook 2025.

By 2030, with a hydrogen price of USD 4/kg, fuel cell and tank costs would still need to drop roughly 60% from 2024 levels for fuel cell and battery electric trucks to reach TCO parity.

Another charging cost increase may come from grid upgrade costs associated with the combination of rapidly expanding electricity demand, projected to grow at nearly 4% per year through 2027, and significant growth of renewable energy capacity. This is expected to require substantial grid reinforcement and new operational approaches. Integrating higher shares of variable renewable energy and new types of demand will necessitate enhanced system flexibility, including investments in enhancing dispatchability of generation, storage systems and flexible demand response, demand side management, and advanced digital technologies to better match supply and demand in real time. These interventions involve significant capital investment, with current annual global spending on grids at around USD 400 billion. The costs of these grid transformations are typically recovered through the grid cost component of electricity prices, affecting all end users. However, the direct impact of these costs on electricity prices will vary by region and depend on factors such as local infrastructure readiness, demand, and the evolving generation mix. In some cases, grid modernisation can improve system efficiency through better optimisation, enhanced flexibility, improved reliability and secure operation, and access to lower-cost renewables, potentially offsetting some cost increases. Given these complexities and the interplay of multiple regional and technological factors, it is not possible to provide a robust quantitative estimate for the impact of grid upgrades on TCO in this analysis.

Another source of uncertainty is the potential role of BETs to offer flexibility to the grid, acting as a dispatchable source of both electricity demand and supply through vehicle-to-grid (V2G) technology. By making use of smart charging and V2G services, electric truck owners could lower their charging costs thanks to the flexibility offered to the grid.

Both the hydrogen price and fuel cell powertrain manufacturing costs would need to fall to help fuel cell trucks become cost-competitive with their battery electric equivalents. When considering a hydrogen price of USD 4/kg delivered to the HRS (i.e. not accounting for refuelling infrastructure costs) in both the European Union and the United States, the fuel cell and hydrogen tank manufacturing costs would need to have fallen by about 25% in 2024, relative to our base case assumptions, and by roughly 60% in 2030, to enable TCO parity between FCETs and BETs. This would translate into breakeven manufacturing costs reaching about USD 100-150/kW for fuel cell systems and around USD 450-500/kg H_2 for hydrogen tanks by 2030. In China, in both 2024 and 2030, even eliminating fuel cell and hydrogen tank manufacturing costs would not make FCETs cost-competitive with their battery electric counterparts due to the low charging costs of BETs.

In many applications and use profiles, FCETs will still trail BETs on cost unless there are substantial drops in hydrogen fuel prices, refuelling stations and fuel cell powertrain manufacturing costs. Public incentives – like direct purchase subsidies or differentiated tax setups – could accelerate cost parity in niche applications, but overall, BETs will remain the more cost-competitive zero-emission option for most heavy-duty use cases.

However, in certain long-haul freight applications, BETs may incur higher dwell time costs than anticipated in this study. Truck fleet operators with strict service-continuity requirements may face increased downtime costs, especially on routes lacking sufficient high-power opportunity chargers. In these cases, the faster refuelling time offered by FCETs may help close service gaps, provided their higher TCO does not outweigh the gains in operational continuity.

Shipping

The fleet of ships able to use hydrogen-based fuels keeps growing, but momentum is slowing down

Maritime shipping has a dual role with respect to hydrogen: both as a means of transport, and as potential major consumer of hydrogen-based fuels, which is the focus of this section.[19]

Alternative fuels – including biofuels, hydrogen and hydrogen-based fuels – are a key component of the decarbonisation of the shipping sector, together with energy efficiency measures and wind assistance. Some of these alternative fuels are “drop-in” fuels, meaning they do not necessitate any major transformation of existing ships. For example, diesel engines can run on biodiesel (with possible blending requirements), while LNG engines can run on biomethane. However, the availability of such fuels is limited by the quantity of available sustainable biomass for biofuels, the high production cost for hydrogen-based fuels, and competition with other sectors. Other alternative fuels are expected to be cheaper or more readily available, but necessitate specific engine and ship designs. Among those, methanol-powered ships are likely to be the most common in the short term, thanks to their technical feasibility: large methanol-powered ships have been on the water since the 2010s, whereas only a couple of small demonstration ammonia-powered vessels are operational at present (see Chapter 5 Investment and innovation). Low-emissions methanol can be either produced from biomass (biomethanol) or synthesised from low-emissions hydrogen, combined with carbon from a sustainable source (either biogenic CO_2 or CO_2 captured from the atmosphere). The two pathways are currently being developed at a similar pace, meaning that, in the initial stages of adoption of methanol in maritime shipping until 2030, both pathways could capture similar market shares.

As of June 2025, more than 60 methanol-powered ships were on the water, although about half were chemical tankers that tend to run on fossil methanol.[20] In 2024, 7 smaller 1 200 twenty-foot equivalent unit (TEU)-capacity containerships were delivered to X-press Feeders, and 7 large 16 000 TEU containerships to Maersk, one of the world's largest shipping companies and a pioneer in the

[19] See Chapter on Trade and Infrastructure of the Global Hydrogen Review 2024 for more information about the status of shipping for transporting hydrogen and hydrogen-based fuels.
[20] Unless stated otherwise, information concerning orderbooks is retrieved from the Ship Register accessed through the UN Global platform.

promotion of methanol ships. As of June 2025, around 300 additional methanol-powered ships were on order books, with an average size of more than 100 000 deadweight tonnes (DWT). Of the ships expected to be delivered in 2028, only one-third have conventional oil engines in gross tonnage, while methanol-powered ships represent about 10%. Those ships are typically fitted with a dual-fuel engine that can operate on both methanol and conventional oil. If their fuel storage system is additionally designed to enable a full voyage on either fuel, they can be fully flexible.

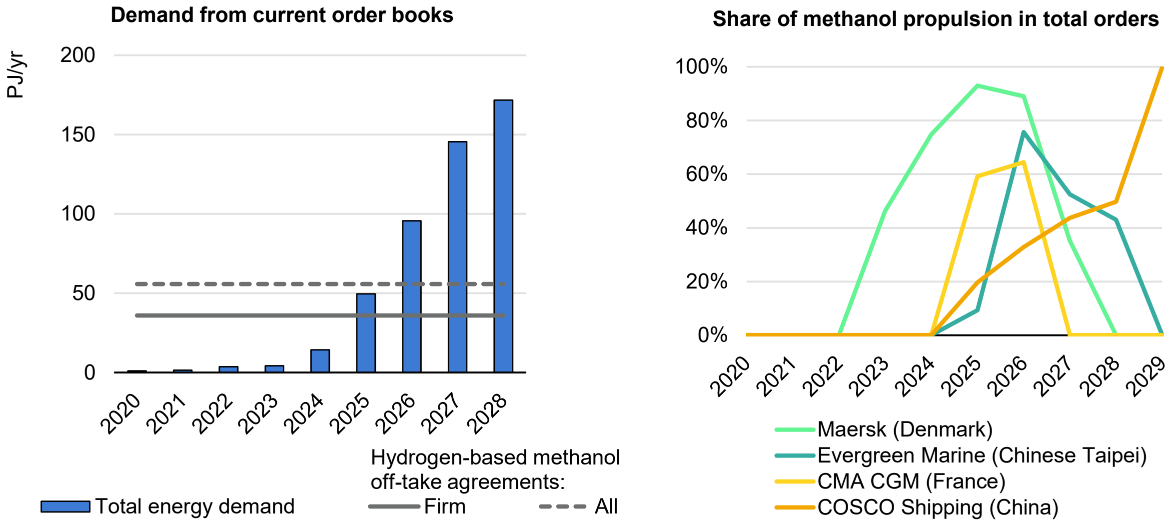
Low-emissions methanol is not a readily available commodity like fossil heavy fuel oil, and ship owners therefore need to set up offtake agreements with producers in order to secure sufficient supplies for their fleets. However, concerns are appearing around the adequacy of alternative marine fuel supply compared to demand in the next few years. For example, Maersk is scaling back the share of methanol on its order books as a hedging strategy to mitigate risk related to fuel supply (Figure 2.16). On the other hand, several shipping companies in Asia are still placing large orders, but do not necessarily make public their offtake agreements. Globally, the share of methanol-powered ships in order books has plateaued for delivery years 2026 to 2028, suggesting momentum is slowing.

In the long run, it is expected that the supply of sustainable biomass for the production of biomethanol and synthetic methanol with CO_2 from biogenic sources will be limited, and that methanol produced from CO_2 captured from the atmosphere will be very expensive. In this context, carbon-free alternative fuels like ammonia and hydrogen appear to be the most scalable solutions.

Ammonia-powered ships are expected to be a cost-competitive option in the long term, but their technological maturity is behind that of methanol-powered ships. Two recent regulatory advances are expected to bring the use of ammonia in shipping closer to commercialisation:

- In December 2024, the IMO revised the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code) to permit the use of ammonia cargo as a marine fuel. This amendment is scheduled to enter into force in July 2026, but flag administrations can opt to apply it before the official enforcement date.
- In September 2024, the IMO Sub-Committee on Carriage of Cargoes and Containers agreed on interim guidelines for the safety of ships using ammonia as a fuel, which aim to minimise the risk to the ship, its crew and the environment. This includes provisions for the arrangement, installation, control and monitoring of machinery, equipment and systems, and gives more certainty to ship-builders, and shipowners considering ordering ammonia-based propulsion ships. These guidelines are expected to be further revised in 2026 or 2027 and eventually incorporated in the mandatory International Code of Safety for Ships Using Gases or Other Low-flashpoint Fuels (IGF Code).

Figure 2.16 Energy demand from methanol-propulsion ships on order books, and share of methanol in order books for selected shipping companies, 2020-2028



Notes: Energy demand of dual-fuel methanol ships can be met with hydrogen-based methanol, biomethanol or oil. Only the offtake agreements for hydrogen-based methanol are shown on the figure. The supply for offtake agreements includes all known announcements, irrespective of their start-up date. Agreements are considered firm if they contain a contractual commitment. Shares of methanol in total orders are calculated based on gross tonnage.

Orders for methanol ships are slowing down amidst concerns around supply of low-emissions fuels.

4-stroke ammonia engines are now commercially available, and suitable for smaller vessels, such as ferries and cruise ships (see Chapter 5 Investment and innovation). Although 2-stroke ammonia engines for large ocean-going vessels are not yet commercial, more than 30 ships, in particular large bulk carriers, LPG tankers and oil tankers, are already on order books, with deliveries expected to start from late 2025. Ammonia bunkering facilities also need to be developed (see Infrastructure at ports).

In addition to hydrogen-based fuels, the direct use of hydrogen is another alternative for decarbonising the shipping sector, but due to its lower volumetric energy density (8 GJ/m^3 for liquid hydrogen vs 37 GJ/m^3 for diesel) and the need for cryogenic storage for liquid hydrogen, hydrogen propulsion is not suited to long voyages. Both hydrogen internal combustion engines (ICEs) and fuel cells are being developed. Hydrogen ICE vessels are at the demonstration stage, while marine applications for fuel cells are at the first-of-a-kind commercial stage (see Chapter 5 Investment and innovation). As of today, 13 hydrogen ICE vessels are operating or on order, which are mainly smaller service vessels like tugs and off-shore crew transfer vessels. In comparison, hydrogen fuel cells have a better energy efficiency and can be fitted on a wider range of ships. A total of 29 such vessels are currently operating or on order, mainly cruise ships and passenger ferries. The IMO interim guidelines for the safety of ships using hydrogen as a fuel are still under discussion and expected to be approved in 2026.

Adoption of low-emissions hydrogen-based fuels in shipping may accelerate following IMO Net-Zero Framework

Regulatory pressure to limit emissions is an important driver for low-emissions fuel[21] deployment; financial support schemes from governments and innovative contractual structures also play a role.

In 2023, the IMO adopted a revised GHG strategy that includes the ambition that so-called "zero or near-zero GHG emission" energy sources make up 5% (striving for 10%) of the energy used by international shipping by 2030. In addition, indicative checkpoints have been defined for the total well-to-wake emissions of the sector, including a reduction of 20% (striving for 30%) by 2030 with respect to 2008 levels, and a reduction of 70% (striving for 80%) by 2040.

As part of strategy implementation, the IMO Net-Zero Framework was approved in April 2025. This sets out regulatory measures comprising a standard on fuel well-to-wake emission intensity and a GHG pricing mechanism. Two fuel emission intensity trajectories have been defined: a base target, and a direct compliance target. Emissions from the use of fuels with an emission intensity above the base target will be subject to "Tier 2" GHG pricing that is initially set at USD 380 /t CO_2--equivalent (CO_2-eq). For fuels with an emission intensity above the direct compliance target, the "Tier 1" pricing is initially set at USD 100/t CO_2-eq. Energy sources with an emission intensity lower than the zero or near-zero threshold, initially set at 19 g CO_2-eq/MJ, will be eligible for a reward (through a mechanism that is still to be defined) (Figure 2.17). Ships using fuels below the direct compliance line are not subject to any pricing and generate surplus units that can be used by other ships to offset their emissions.

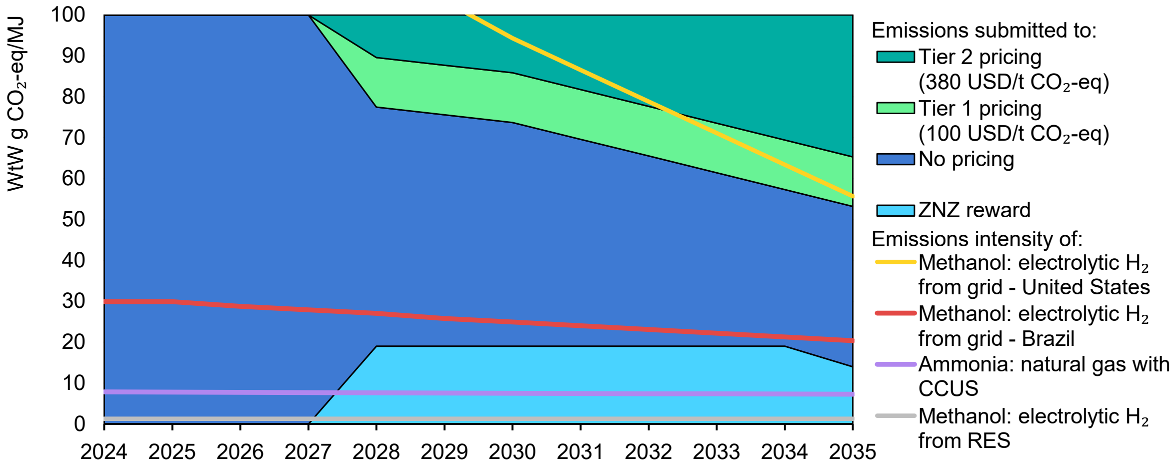
The money collected by the IMO through the GHG pricing mechanism is expected to be in the billions of dollars per year in the first years, and will go into the IMO's Net Zero Fund. It will then be disbursed to reward ships using low-emissions technologies, support infrastructure and transition initiatives, and mitigate negative impacts on vulnerable countries such as Small Island Developing States and Least Developed Countries. Final adoption of the Net-Zero Framework is expected in October 2025, and it will come into force in Q1 2027. The fuel emission intensity trajectories are currently defined annually for the period 2028-2035, with a value already set for the base target in 2040. A planned revision before the end of 2031

[21] Includes bioenergy, low-emissions hydrogen and low-emissions hydrogen-based fuels.

will extend the yearly coverage until 2040. This gives a clear signal to the industry, removing a lot of the uncertainties that have hindered investment in alternative fuel production and use.

Some of the details of the Net-Zero Framework are not yet defined, so its potential impact on the uptake of hydrogen-based fuels is still to be determined. While some research suggests it will favour the deployment of ammonia in the medium term, others estimate that it could favour first-generation biofuels or even LNG in the short term. A lot will hinge on the guidelines to be developed in the next few months,[22] and in particular on the default emission factors included in the guidelines on life-cycle GHG intensity of marine fuels.

Figure 2.17 International Maritime Organization Net-Zero Framework emission pricing and emission intensity of selected hydrogen-based marine fuels, 2024-2035



Notes: WtW = well-to-wake; CCUS = carbon capture use and storage; RES = renewable energy source; ZNZ = zero or near-zero. The methanol routes consider the use of biogenic CO_2. The calculation of the WtW emissions of the electrolytic routes consider a carbon intensity of the electricity used in line with the IEA's Stated Policies Scenario (STEPS). Ammonia from electrolytic H_2 from grid is about 5% lower than its methanol counterpart and is not represented on the graph.

The IMO Net-Zero Framework reduces uncertainties for investors and can incentivise the use of hydrogen-based fuels.

In the European Union, the FuelEU regulation came into force in January 2025. This includes a standard on the emission intensity of fuels, with a trajectory where the value permitted declines every 5 years, from -2% in 2025, through -14.5% in 2035 and -80% in 2050, compared to 2020 levels. There is also an incentive to use RFNBOs through a reward factor with a value of 2 until 2033 (and 1 afterwards): when calculating the average emission intensity of the fuels used by a ship, the emissions are divided by the quantity of fuel consumed, with the

[22] See IMO MEPC/ES.2/3 for the detailed work plan.

quantity of RFNBOs being multiplied by the reward factor. The RFNBO "sunrise clause" also states that, if in 2031 the share of RFNBOs in the yearly energy used on-board ships is less than 1%, a mandatory quota of 2% RFNBOs shall apply by 2034. The EU RED regulation also stipulates that EU member states with maritime ports shall ensure that the share of RNFBOs in the total amount of energy supplied to the maritime sector is at least 1.2% by 2030. Currently, EU regulations and the proposed IMO Net-Zero Framework exist in parallel, with the potential for a double reporting system and double taxation. However, the FuelEU documentation notes that the regulation will be reviewed with a view to alignment with international rules once the details of the Net-Zero Framework become clearer.

Several private sector initiatives also aim to take advantage of cargo-owners willingness to pay for low-emission transportation of goods. For example, the Katalist book-and-claim platform was started in late 2024 by the Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping and RMI. Under this system, freight customers can purchase emission savings from vessels using low-emissions fuels, even if their cargo is not transported on those specific vessels. The Zero Emission Maritime Buyer Alliance, established in 2023, announced in February 2025 that it is accepting bids for its second e-fuel-focused tender, with results expected by the end of 2025 and fuel delivery starting in 2027. The corresponding e-fuel demand is expected to be on the order of hundreds of kilotonnes over the 3-5-year period of the tender. This process enables interested cargo-owners to pool their resources together.

Aviation

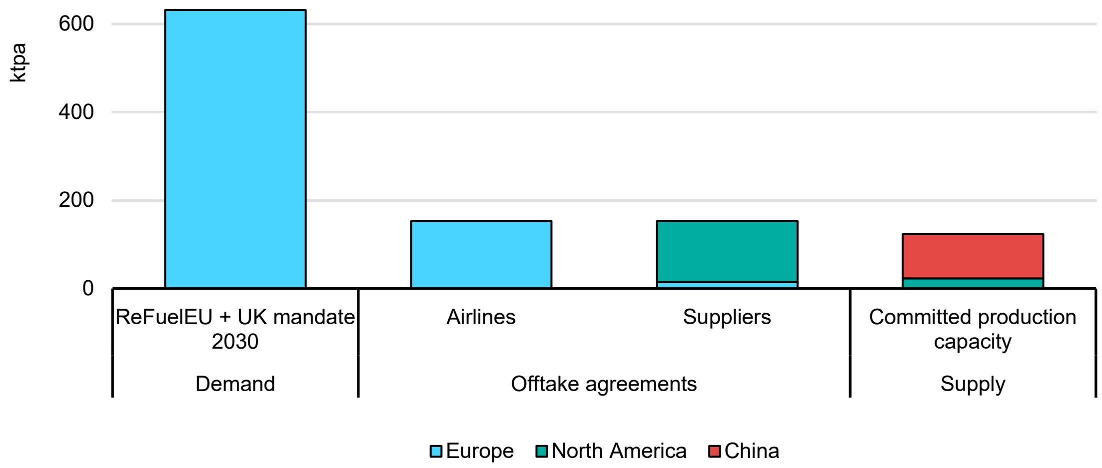
Use of synthetic hydrogen-based fuels can kick-start demand in aviation, but offtake remains small and concentrated in Europe

Today, over 99% of the fuel used in aviation is fossil jet kerosene. Excluding demand for hydrogen in refining activities to produce fossil and bio-jet kerosene (see Demand in oil refining), aviation has negligible demand for hydrogen and hydrogen-based fuels today. However, this could soon change following policy action in some regions. Over the past 2 years, both the European Union and the United Kingdom have introduced sustainable aviation fuel (SAF) blending mandates, setting progressively higher minimum quotas for SAF and including specific lower limits for hydrogen-based aviation fuels (e-SAFs). In 2030, 1.2% of aviation fuel demand must be met with RFNBOs in the case of the ReFuelEU Aviation regulation,[23] and 0.6% of demand with e-SAF in the UK regulation. These blending mandates are set to create demand for more than 600 ktpa of synthetic kerosene, which could entail a demand of up to 170 ktpa of low-emissions

[23] ReFuelEU sets 1.2% as the average share over the years 2030 and 2031 with a minimum share of 0.7% per year.

hydrogen,[24] positioning Europe as the lead market for e-SAF adoption. E-SAF can be used as drop-in fuel, although the blending share has been limited to 50% to date. Certification of fuels, aircraft and engines for 100% SAF use is expected within this decade.

Figure 2.18 Demand for and supply of synthetic kerosene by region towards 2030



Notes: Airlines are distributed across regions according to the location of the company headquarters, although the fuel included in the offtake may also be used in other regions. Demand is taken from the IEA's Stated Policies Scenario. In 2030, ReFuelEU sets the minimum share of synthetic kerosene at 1.2%; the UK mandate at 0.6%. Only firm offtake agreements are included. Production from plants counted towards "committed production capacity" has yet to be certified to comply with the definition of renewable fuels of non-biological origin (RFNBO) under EU and UK law.

Europe has positioned itself as a lead market for synthetic kerosene, though offtake agreements and production capacity have not yet caught up.

Multiple airlines have already struck alliances with synthetic fuel producers, but firm offtakes cover less than a quarter of mandated demand in 2030. In May 2025, Infinium reached FID on a 23 ktpa synthetic fuel plant in Texas, following an offtake agreement with IAG for 7.5 ktpa of e-SAF in 2024. IAG signed a larger deal with Twelve, in early 2024, for 785 kt over 14 years. United Airlines also recently invested in Twelve, adding to the over USD 700 million raised by the company since September 2024. In late 2023, Air France-KLM invested USD 4.7 million in synthetic fuel producer DG Fuels, including options to buy 75 ktpa, and signed preliminary offtake agreements with SAF+, and Engie. Lufthansa group and its subsidiary SWISS have invested in Synhelion, which is operating a first small-scale e-SAF plant in Germany and is developing a project for a 1 ktpa plant in Spain, with the objective of starting production in 2027.

E-SAF production will need to ramp up soon to meet demand in 2030. A large number of projects are in the pipeline, with more than half of the announced

[24] Assuming that all synthetic kerosene is produced through the Fischer-Tropsch route.

volume located in Europe, and over 40 projects for a combined capacity of 2 800 ktpa – more than four times more than the minimum needed to meet the implemented mandates in 2030. However, few projects have reached FID to date, partly because policies have only been implemented very recently. In early 2025, industry initiative SkyPower called for more political support regarding financing, derisking and long-term certainty on fuel mandates to address the uncertainties facing e-SAF projects today. Such support is urgently needed for projects to reach FID. Given that constructing a production facility typically takes 3-4 years, it could become increasingly difficult to meet the mandates in Europe if no FIDs are taken within the next couple of years. Outside Europe, there is currently little political stimulus to boost e-SAF demand. The picture on the supply side is different, however, as US-based fuel producers have taken the first FID on an e-SAF plant and have secured the largest offtakes so far, while some of the world's largest e-SAF projects are being developed in China. Energy China started construction of the first phase (100 ktpa) of a 300 ktpa plant in north-east China in 2024, and another agreement was reportedly signed between Shanxi International Energy Group and a local government to construct a 350 ktpa e-SAF plant.

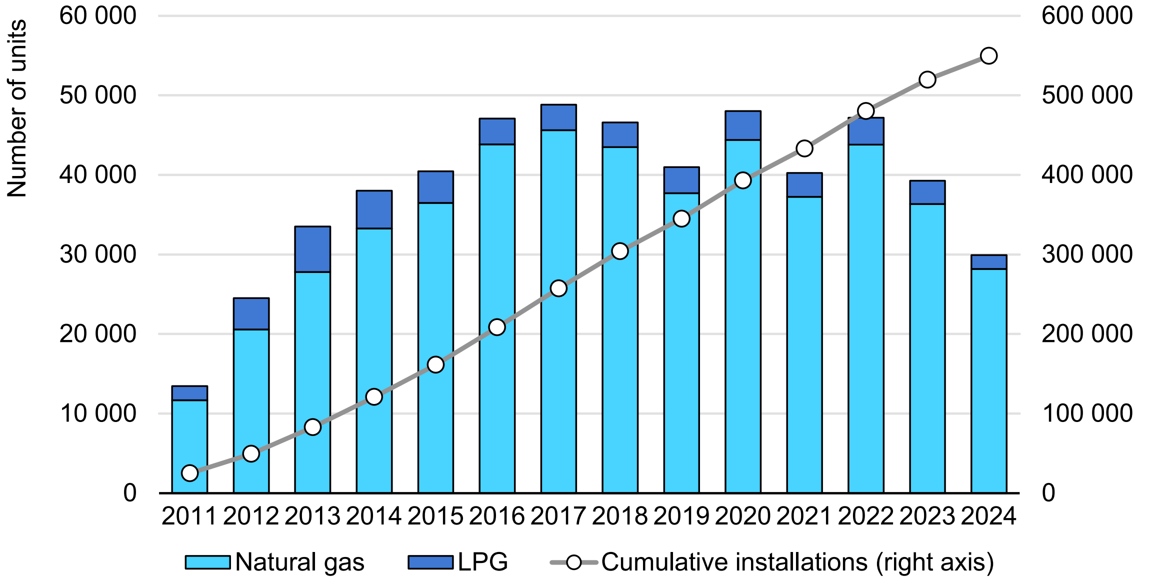
Technology to use hydrogen on planes directly – in fuel cells or gas turbines – is under development (see Chapter 5 Investment and innovation). Key technical challenges involve redesigning aircraft to house larger tanks and establishing infrastructure for safely handling cryogenic fuels at airports. Hydrogen-powered flight a took step towards commercialisation in 2024 when Joby Aviation flew a small hydrogen-electric vertical take-off and landing aircraft over more than 800 km. In the same year, American Airlines signed a conditional purchase agreement with ZeroAvia for 100 hydrogen-electric (fuel-cell) engines for regional planes. In contrast, in a setback to the prospects of commercial application on larger aircraft, Airbus announced a delay to the launch of a hydrogen-powered commercial airliner that was originally planned for 2035, citing doubts about sufficient low-emissions hydrogen supply and challenges with establishing infrastructure and regulation. To address some of these issues, the European Union and Airbus are funding the GOLIAT project to develop technology needed for the safe handling of hydrogen at airports. Meanwhile, over 220 airports are collaborating on the Hydrogen Hubs at Airports project, to advance on infrastructure, regulatory and operational challenges.

Demand in buildings

The contribution of hydrogen to meet energy demand in residential and commercial buildings remains negligible, with no significant developments in 2024. Electrification, district heating and distributed renewables remain far ahead of technologies using hydrogen in fulfilling this need.

Similarly, there was very little progress in 2024 in the deployment of technologies that are capable of running on hydrogen. Where fuel cells are installed – mostly in Europe, Japan, Korea and the United States – they predominantly run on natural gas, which is pre-reformed into hydrogen in the fuel cell before being used to produce heat and power. In Japan, the stock of deployed fuel cell micro-combined heat and power units reached 550 000 at the end of 2024. Although yearly installations declined by around 25%, the total installed capacity continued to grow in 2024, supported by the ongoing ENE-FARM technology programme (Figure 2.19).

Figure 2.19 Yearly and cumulative shipments of fuel cell micro-combined heat and power units in Japan, 2011-2024



Source: IEA analysis based on data from the Advanced Cogeneration and Energy Utilization Center of Japan (ACEJ).

Around 550 000 fuel cells have been installed in Japan since the ENE-FARM programme was launched in 2009 – an average of around 35 000 units per year.

Advances in the use of pure hydrogen in buildings – mostly in boilers – are still limited to small-scale pilots and demonstration projects. However, a significant number of these projects face low social acceptance or have proved not financially viable. For example, in Stad aan 't Haringvliet (the Netherlands) the existing natural gas network was supposed to be converted to distribute hydrogen for residential heating, but the project is now in jeopardy due to questions about its economic feasibility. As of early 2025, the project is evaluating the use of a hybrid system, combining heat pumps and hydrogen boilers, to reduce the demand for hydrogen and improve the economics. Similarly, in Lochem (the Netherlands), the trial to test hydrogen boilers in 12 homes will conclude in 2025, when all homes will be reconnected to the natural gas grid, as the pilot had proved financially unsustainable. The H2Direkt project, located in Hohenwart (Germany), was launched in 2023 to provide hydrogen for heating via existing natural gas infrastructure to ten households and one commercial building. For this pilot, hydrogen was delivered by trailer. However, in 2025, a follow-up project, H2Dahoam, was launched to produce hydrogen onsite using solar-powered electrolysis, with the goal of beginning operations in 2027. In Hoogeveen (the Netherlands), a hydrogen heating pilot received the green light after a 1-year delay, and renewable hydrogen was delivered to the first home in September 2024. In Edmonton (Canada) the first Canadian hydrogen-powered house had been developed by the end of 2024.

Demand in power generation

Japan and Korea lead efforts on the use of hydrogen-based fuels in power generation, but progress remains slow

Hydrogen and ammonia can become an important source of low-emissions electricity system flexibility and are among only a few options for large-scale and seasonal electricity storage, particularly in electricity systems with high shares of variable renewable electricity generation and limited other flexibility or long-term storage options.

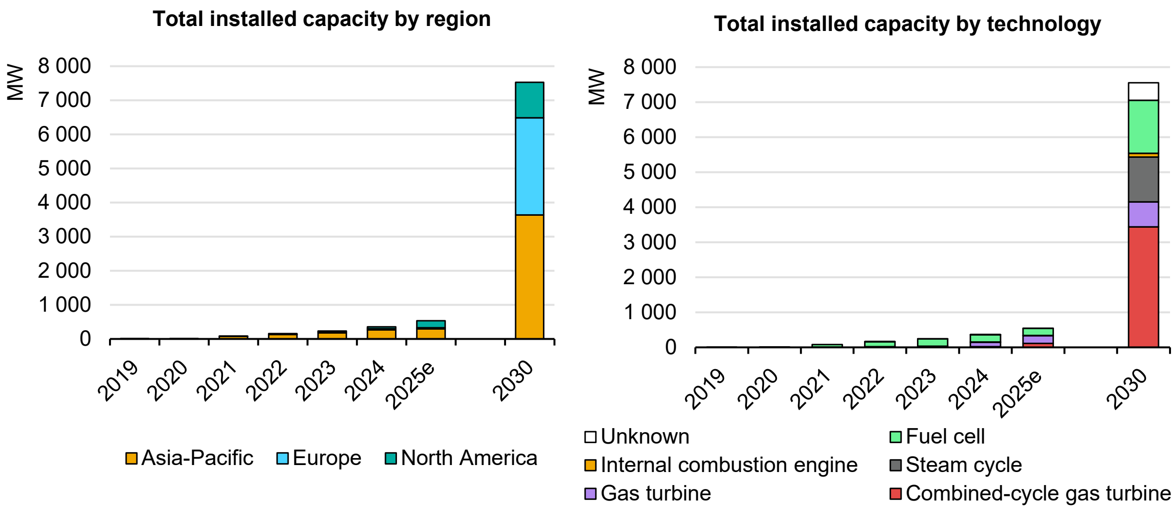
The global installed power capacity using hydrogen or ammonia reached 360 MW at the end of 2024, an increase of 50% compared to 2023, albeit representing less than 0.01% of the total global capacity of the power sector.[25] Around 75% of the hydrogen- or ammonia-fired capacity is located in the Asia-Pacific region, 15% in North America and 10% in Europe.

Based on announced projects,[26] the power capacity using hydrogen and ammonia could reach 7 500 MW by 2030 (or 4 900 MW if projects at very early stages of development are excluded) (Figure 2.20). This represents an increase of 6% compared to the corresponding capacity identified in the GHR-24. The Asia-Pacific region accounts for almost half of announced capacity by 2030, followed by Europe with 38% and North America with 14%. Japan and Korea alone account for more than a third of the announced power capacity by 2030. Most projects in Korea focus on the use of hydrogen, while both hydrogen and ammonia projects are under development in Japan.

[25] In the case of co-firing hydrogen or ammonia, the capacity corresponds to the total installed capacity multiplied by the co-firing share in energy terms. Plants using mixed gases containing hydrogen from steel production, refineries or petrochemical plants are not included.
[26] Announced projects include plants that are under construction, have reached FID, are under feasibility study or at an earlier development stage.

Several projects aiming to use 100% hydrogen have been announced over the past 12 months. In Korea, Korea Southeast Power and Samsung C&T presented plans for a 900-MW combustion power plant running on local renewable hydrogen. A 108-MW fuel cell power plant is already under construction in Korea, while in China a 40-MW fuel cell power plant is being built by the China Energy Engineering Corporation. In the United States, Duke Energy plans to start commercial operation of a 75-MW gas turbine in 2025, running on 100% renewable hydrogen. However, projects have also been delayed or cancelled. In South Australia, plans to build a 200-MW gas turbine power plant running on renewable hydrogen were deferred in early 2025. With the relatively large hydrogen or ammonia volumes needed for commercial power plants (e.g. 10 GW of gas turbine capacity running 100% on hydrogen with 2 000 full load hours and efficiency of 40% would require 1.5 Mtpa of hydrogen), the slow development of the hydrogen sector in terms of cost reductions and infrastructure, as well as regulatory or political uncertainties, are mentioned as reasons for projects being postponed or cancelled.

Figure 2.20 Power generation capacity using hydrogen and ammonia by region, historical and from announced projects, 2019-2030



Notes: Values for 2025 are estimates, assuming plants with an announced start date in 2024 that are under construction or have reached FID actually start operation in 2025.
Sources: IEA analysis based on announcements from industrial stakeholders; ERM for fuel cells.

Based on existing plants and announced projects, hydrogen- and ammonia-fired power capacity could reach 7 500 MW by 2030.

With regards to technology, fuel cells account for more than 55% of today's installed power capacity using hydrogen and ammonia. The remainder is mainly based on open-cycle and combined-cycle gas turbines. By 2030, the share of fuel cells among the announced projects declines to 20%, while open-cycle and combined-cycle gas turbines reach a share of 55%. Projects planning to co-fire ammonia in coal power plants reach a share of more than 15%, almost all located in the Asia-Pacific region. Though not reflected in the announced projects, development efforts are also underway to demonstrate direct 100% ammonia gas firing in larger gas turbines, after the direct use of 100% ammonia was demonstrated in a 2-MW gas turbine in 2022 in Japan. Manufacturers are also working on retrofittable ammonia combustion systems for existing gas turbines.

With today's gas turbines technologies being able to co-fire high shares of hydrogen, several utilities have announced plans to build gas power plants that are "H_2-ready" or to retrofit existing plants for hydrogen co-firing. Current gas turbines can already use 100% hydrogen, using diffusion combustion, but steam or water injection is used as a measure to reduce nitrogen oxides (NOx) emissions. Manufacturers are confident in their ability to commercially provide, by 2030, modern large-scale gas turbines (using dry low-NOx combustion systems) that can run entirely on hydrogen with very low NOx emissions, avoiding the efficiency penalty of diffusion combustion systems. In June 2025, a 50% hydrogen co-firing share was successfully demonstrated in an existing 283-MW gas turbine in the United States. In Japan, the utility Kepco has been running a unit at its 2 919 MW Himeji Daini gas-fired power plant at a 30%-hydrogen co-firing share since April 2025. A combustion system using 100% hydrogen for existing and new gas turbines was demonstrated by a manufacturer in early 2025. Based on announcements by utilities, the share of H_2-ready announced capacity corresponds to almost 20 GW. However, this number is likely to represent a lower range, given that it is based only on projects for which relevant information has been released. In addition, other new gas-fired power plants in planning are also likely to be able to co-fire a certain amount of hydrogen, although no information has been made available yet. Likewise, many existing gas-fired power plants are able to co-fire certain shares of hydrogen, varying from 5% to 100%, depending on the gas turbine design.[27] Based on information on existing gas turbines in operation, and their maximum hydrogen blending shares as specified by gas turbine manufacturers, their hydrogen-fired capacity could amount to more than 130 GW globally.[28] As before, this represents a lower bound, given that detailed information was only available for 1 500 GW of the existing total gas-fired capacity of 2 000 GW in 2024, and retrofits can increase the capability of existing gas turbines to use hydrogen.

[27] Other factors, such as the capability of the gas supply pipes and valves to handle certain hydrogen blending shares are not considered here, but are, of course, critical to assessing specific plants.
[28] Derived by taking the maximum co-firing share multiplied by the total capacity for individual plants. The total capacity of these plants capable of hydrogen co-firing amounts to 950 GW.

The high premium for using low-emissions hydrogen-based fuels in power generation requires strong policy support

In the coming years, low-emissions hydrogen and ammonia are likely to remain expensive energy carriers for power generation. They can benefit from higher prices during peak hours in wholesale electricity markets, and from carbon pricing having been introduced in many countries in the power sector. Nevertheless, if countries want to demonstrate the use of hydrogen and ammonia in power generation, policy support will be needed to close the cost gap. Since the GHR-24, several countries have introduced support measures or continued existing instruments for the use of low-emissions hydrogen or ammonia in the power sector, in particular through auctions or tenders.

Korea presented its 11th Basic Electricity Supply and Demand Plan in February 2025. According to the plan, electricity generation from low-emissions hydrogen and ammonia will almost triple between 2030 and 2038 from 15.5 TWh to 43.9 TWh, which would correspond to a 6.2% share of electricity in 2038. In Korea's first tender of up to 6 500 GWh of electricity annually generated from clean hydrogen and ammonia, only the state-owned utility Korea Southern Power (Kospo) was selected in 2024. Kospo plans to generate 750 GWh per annum by co-firing ammonia in its Samcheok Unit 1 coal power plant from 2028 onwards. In May 2025, a second tender was announced, targeting 3 000 GWh and requiring successful bidders to start operation within 3 years. As in the first tender, the emissions intensity of hydrogen has to be below 4 kg CO_2-eq/kg H_2, and the offtake contracts run for 15 years. While the first tender included only fixed exchange rates, the second round introduces an exchange rate indexation to reflect that the subsidy is in Korean won, but hydrogen or ammonia supply prices, particularly if imported, are often based on USD. The second tender also gives flexibility to shift production of up to 10% of the annual contact volume between subsequent years. Korea also opened in May 2025 a fourth tender for general hydrogen, which does not include any emissions thresholds. The auction awarded in August 2025 52 projects with a combined electricity generation volume of up to 1 355 GWh. The winners of the previous third general hydrogen tender were announced in September 2024, with 16 projects with a combined generation of 1 314 GWh being successful. The first two general hydrogen tenders took place in 2023 and awarded 24 projects with a combined generation of 1 430 GWh from general hydrogen.

In Japan, the results of the second Long-Term Decarbonization Auction (LTDA) were released at the end of April 2025. Among the selected projects, only one was linked to the use of hydrogen or ammonia in power generation. Shikoku Electric Power plans to co-fire ammonia with a corresponding capacity of 94.6 MW at its Unit 1 of the Saijo coal power plant with a total capacity of 500 MW, resulting in a co-firing share of 20%. In the first LTDA in 2024, ammonia and hydrogen in power generation played a larger role: Five coal power plants with ammonia co-firing and a coal-fired power plant with hydrogen co-firing were among the winners. The LTDA offers 20-year offtake contracts, providing demand certainty. Successful bidders have to refund 90% of revenues gained from other markets, such as wholesale electricity or capacity markets. Ongoing improvements are being considered in preparation towards the third LTDA for 2026, such as expanding support for the fuel costs of hydrogen and ammonia and raising the ceiling price.

Indonesia released a National Hydrogen and Ammonia Roadmap in April 2025. For the power sector, this includes the targets to demonstrate 10% ammonia co-firing in coal power plants by 2030 and a 30% share by 2035. By 2045, the goal is to have 2 GW of 100% ammonia-fired capacity installed and to reach a 60% hydrogen co-firing share in gas-fired electricity generation. For 2060, the roadmap aims to have 25.3 GW of 100% hydrogen-fired capacity and 8.4 GW of 100% ammonia-fired capacity.

In its Sixth National Development Plan, Namibia sets the target to generate by 2030 143 GWh of baseload electricity from hydrogen, an amount corresponding to around 4% of Namibia's electricity supply in 2022, of which almost 70% was imported. HDF Energy is planning a renewable electricity project in Namibia, combining solar PV with batteries, an electrolyser, hydrogen storage and fuel cells to ensure a stable electricity output of 30 MW during the day and 6 MW during the night.

Chapter 3. Hydrogen production

Highlights

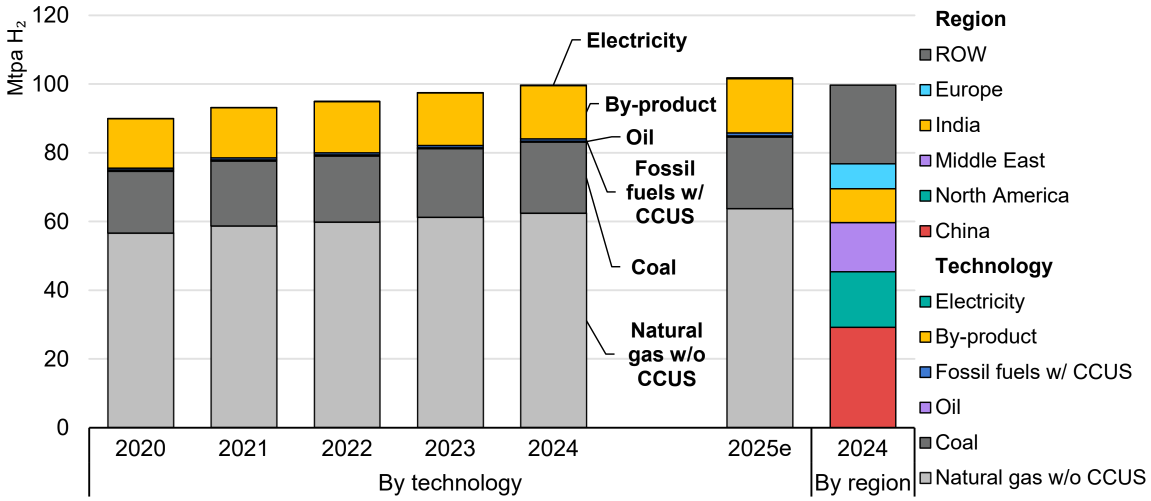
- Hydrogen production reached almost 100 Mt in 2024, but less than 1% was based on low-emissions hydrogen technologies. Based on announced projects, low-emissions hydrogen could reach 37 Mtpa by 2030, a reduction from the 49 Mtpa estimated in the Global Hydrogen Review 2024 (GHR-24).
- More projects are reaching final investment decision (FID), although the total production capacity reaching this stage in 2024 remained at the same level as in 2023. Persisting technical and regulatory barriers, financial obstacles and challenges in securing reliable offtake, in particular, continue to delay and occasionally completely stall project progress.
- Despite announced delays and cancellations, low-emissions hydrogen production is expected to increase significantly by 2030. Based only on projects that are operational, have already reached FID or are under construction, low-emissions hydrogen production can reach more than 4 Mtpa by 2030.
- For the first time, this report systematically assesses the likelihood of announced projects going ahead by 2030. This analysis suggests that 10 Mt of low-emissions hydrogen production is almost certain or has strong potential to be operational by 2030, if the right policy efforts to stimulate demand in traditional applications and emerging sectors are implemented. However, another 19 Mt is from projects that have low potential or are uncertain to be operational by 2030 considering the short time remaining for those projects to materialise.
- Low-emissions hydrogen production will remain more costly than unabated fossil-based production in the near term, with cost projections for electrolysers being less optimistic than in previous years due to the limited deployment achieved to date. However, this cost gap is still expected to narrow by 2030, with China reaching cost competitiveness thanks to low technology costs and a low cost of capital, and other regions reducing the cost gap significantly due to the combination of high cost of imported natural gas, good renewable resources and policy action in the form of CO_2 prices (e.g. Europe, Latin America) .
- China leads on electrolyser manufacturing, deployment and cost-competitiveness. This has raised concerns about a repetition of the story of the solar PV or battery sectors, for which China now holds the large majority of the supply chain, having overtaken other regions that were first movers years ago. However, using Chinese-manufactured electrolysers outside of China is expected to lead to only very modest cost savings.

Overview and outlook

Global hydrogen production neared 100 Mt in 2024, dominated by unabated fossil-based routes

Global hydrogen supply rose by approximately 2% in 2024 compared with 2023, reaching almost 100 Mt H_2. Supply is poised to exceed the 100 Mt H_2 milestone in 2025 (Figure 3.1). Production remains largely co-located with demand, with minimal international trade today. As a result, regional output mirrors consumption patterns, with China accounting for almost 30% of global hydrogen, followed by North America and the Middle East, each contributing around 15%.

Figure 3.1 Hydrogen production by technology and by region, 2020-2025e



Notes: CCUS = carbon capture, utilisation and storage; ROW = rest of world; 2025e= estimate for 2025, based on trends observed until July 2025. By-product hydrogen includes production in catalytic naphtha crackers and steam crackers which is subsequently used in refining.

Hydrogen production remains dominated by unabated fossil fuels and is largely concentrated in a few key regions.

Unabated fossil fuels dominate the hydrogen supply chain, with low-emissions hydrogen accounting for less than 1% of total supply. Deployment of low-emissions hydrogen production technologies faces significant barriers, as the system is deeply locked-in due to sunk costs in existing production capacities and established infrastructure. Enabling a structural shift will therefore require ambitious policy action. Production from natural gas reforming supplies nearly two-thirds of total demand, benefitting from well-developed infrastructure and established cost advantages. Coal-based hydrogen accounts for the second-largest share, concentrated primarily in China and, to a much smaller extent, India, where integrated coal and chemical complexes supply refineries and fertiliser plants. By-product hydrogen recovered from gaseous streams in refineries and petrochemical facilities (e.g. naphtha crackers and steam crackers) adds a further portion, but this remains a secondary contributor compared with dedicated production. Reliance on unabated fossil fuel pathways generated roughly 980 Mt CO_2 in 2024,[29] (around 3% more than in 2023), more than the combined annual emissions of Indonesia and France.

Low-emissions hydrogen remained under 1% of production in 2024, but is expected to reach 1 Mt in 2025

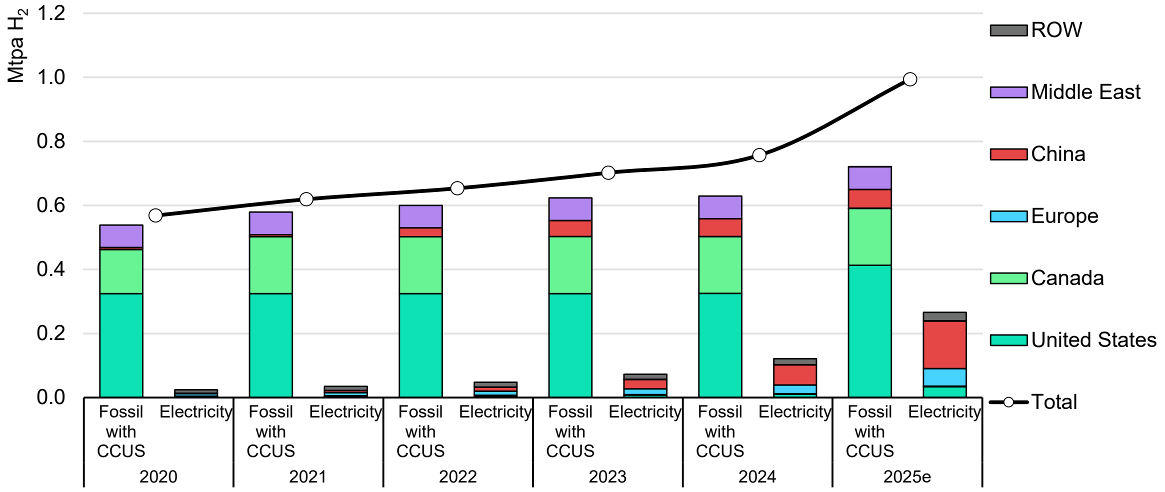
Low-emissions hydrogen production has grown steadily since 2020, albeit from a very low base. In 2024, output reached almost 0.8 Mt H_2, representing less than 1% of total global supply, but a near 10% increase on 2023 output (Figure 3.2). Existing low-emissions volumes come predominantly from a small number of fossil fuel facilities in North America that integrate partial carbon capture, utilisation and storage (CCUS). However, no new CCUS fossil fuel projects commenced production in 2024; instead, most of the growth stems from electrolyser-based units that began operation in 2023 (and ramped up production last year) and 2024. A handful of small biomass-to-hydrogen and methane-pyrolysis ventures also contribute, but their combined output remains marginal.

Electrolysis-derived hydrogen surged by 60% year-on-year in 2024 to reach more than 100 kt H_2, with the bulk of new capacity coming online in China. Despite this progress, electrolysis still represents only around one-sixth of total low-emissions hydrogen production, highlighting that scaling up water-splitting technologies remains a challenge, but that there are opportunities.

Based on projects under construction or that have reached FID, production is expected to jump by around 30% to reach 1 Mt in 2025. Approximately 40% of this growth stems from a large CCUS project led by CF Industries that started operations in July in the United States. The other 60% of expected growth is from electrolyser projects, which could more than double their 2024 output. China remains the primary driver of electrolysis growth, followed by Europe and the United States.

[29] Considering 0 kg CO_2/kg H_2 for hydrogen produced as a by-product in naphtha crackers and steam crackers. Considering a maximum of 10 kg CO_2/kg H_2, emissions would increase to more than 1 100 Mt CO_2. This includes direct emissions from hydrogen production and more than 300 Mt of CO_2 utilised in the synthesis of urea and methanol, the majority of which is later emitted. This excludes upstream and midstream emissions for fossil fuel supply.

Figure 3.2 Low-emissions hydrogen production, 2020-2025e



Notes: CCUS = carbon capture, utilisation and storage; ROW = rest of world; 2025e = estimate for 2025, based on projects planned to start operations in 2025 that have at least reached FID.
Source: IEA Hydrogen Production Projects Database (September 2025).

Low-emissions hydrogen production remains concentrated in CCUS projects in North America, but electrolytic hydrogen production in China is growing fast.

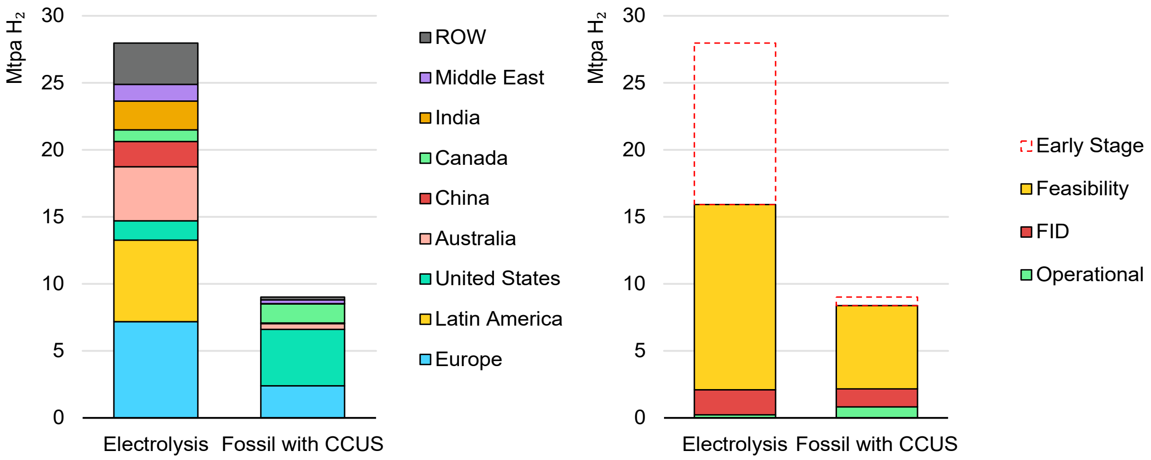
Low-emissions hydrogen production could reach 37 Mtpa by 2030, but this volume has shrunk since last year

Globally, announced projects for producing low-emissions hydrogen could increase production to 37 Mtpa by 2030 (Figure 3.3). This assessment includes only projects using low-emissions electricity in electrolysers and fossil fuel with CCUS, and excludes smaller initiatives like biomass-based routes (that could produce less than 1 Mtpa) or underground natural hydrogen, which remains at early stages, despite recent interest, and is not expected to contribute meaningfully by 2030 (see Chapter 5: Investment and innovation).

For the first time since the IEA's Global Hydrogen Review 2021, the 2030 potential has declined from the estimate of the previous year (49 Mtpa reported in the GHR-24). This reflects three principal factors. First, delays have pushed back expected start dates for several projects to after 2030. Second, a number of projects have been placed on indefinite hold pending improved market conditions or revised business cases. Third, definitive project cancellations have removed capacity from the pipeline. On aggregate, a breakdown of projects in the pipeline shows a maturation pattern, in which early-stage projects without a clear business case cannot progress toward more advanced stages in the near term. On the other hand, projects with strong business cases and access to supportive policies to bridge the gap in cost-competitiveness with unabated fossil fuel-based production (see A closer look at the hydrogen production projects that have been cancelled reveals that specific barriers such as regulatory and permitting issues (44%), economic challenges (28%), technical difficulties (13%), and lack of prospective clients (9%) were frequently cited as reasons for cancellation. In addition, a notable 31% of cancellations correspond to projects that were cancelled at early stages of development that often referred to overambitious assumptions on cost reductions or premature expectations of market development as key reasons for cancellation (Figure 3.7). These figures highlight how the initial wave of announcements often lacked alignment with real market and policy conditions, reinforcing the notion that the sector is now consolidating around more mature projects with solid business cases. Projects of this kind combine technical maturity, commercial realism and alignment with government ambitions for decarbonisation and enhancement of energy security, but they will still need policy support to materialise.

Cost comparison of different production routes) can reach more advanced stages. Projects at FID rose by more than 15% to 3.2 Mtpa this year (from 2.8 Mtpa in GHR-24[30]), those in feasibility studies fell by 7% to 19 Mtpa, while early-stage developments fell by 45%. Despite these signs of maturation, the share of announced production at FID edged up only modestly, from 6% to 9% of the pipeline.

Figure 3.3 Low-emissions hydrogen production by technology, region and status based on announced projects, 2030



Notes: CCUS = carbon capture, utilisation and storage; FID = final investment decision; ROW = rest of world. FID 2030 includes projects that have reached FID and those that are under construction. “Feasibility” includes projects undergoing a feasibility study; “Early stage” includes projects at early stages of development, such as those for which only a co-operation agreement among stakeholders has been announced. Only planned projects with a disclosed start year of operation are included. More details about announced projects for low-emissions hydrogen production can be found in the new Hydrogen Tracker available on the IEA website.
Source: IEA Hydrogen Production Projects Database (September 2025).

Low-emissions hydrogen production could reach 37 Mtpa by 2030, but only 4.2 Mtpa are operational, under construction or have reached FID.

[30] This value differs from the value published in the GHR-24 as it excludes a large Air Products CCUS project in Louisiana (United States) that announced an FID in 2023. However, the latest statement of the company from May 2025 notes that the investment for this project is not yet committed, until enough offtake can be secured.

At the regional level, Europe continues to have the largest project pipeline, accounting for nearly one-quarter of potential production from announced projects by 2030, despite a 20% y-on-y decline, driven by slow market uptake and halts to projects found to lack a viable business case. North America and Latin America represent about 20% and 15% of the global pipeline, respectively. In both regions projects in the pipeline fell by around 10% and 15% respectively. In North America, this decline was largely in the United States amid policy uncertainty due to the review of support for low-emissions hydrogen under the Inflation Reduction Act (IRA). In Latin America, the drop reflected the postponement or cancellation of more than half of Chile's projects, even as Brazil's capacity soared 60%, boosted by the announcement of its new hubs programme. China's announced capacity increased by 30%, driven entirely by electrolyser projects.

With regards to technology, both electrolysis and CCUS segments contracted: electrolysis potential production fell 25% and CCUS projects declined 20%. European CCUS suffered the greatest reduction, although greater openness among governments to support CCUS technologies may rekindle interest in the most advanced projects in the region (see section on Fossil fuels with CCUS).

Yearly final investment decisions remained above 1 Mtpa in 2024

The pace of FIDs offers a window into near-term delivery prospects. In 2023, FIDs reached a record 1.1 Mtpa, [31] driven by five large CCUS commitments and a five-fold increase in electrolysis, with the NEOM Green Hydrogen Project alone accounting for nearly 40% of the volume of FIDs for electrolysis (Figure 3.4).

In 2024 the capacity advancing to FID reached again more than 1 Mtpa, but technology trends differed. There was a significant slowdown in CCUS project approvals: only two smaller CCUS facilities reached FID. In early-stage markets, where a handful of very large projects dominate decisions, fluctuations in a few announcements can produce large swings in total capacity at FID. Electrolysis projects bucked this trend, continuing their upward trajectory with a 85% increase in FID capacity to almost 1 Mtpa. Not only more projects reached FID in 2024, but also the average electrolyser project size at FID nearly doubled. [32]

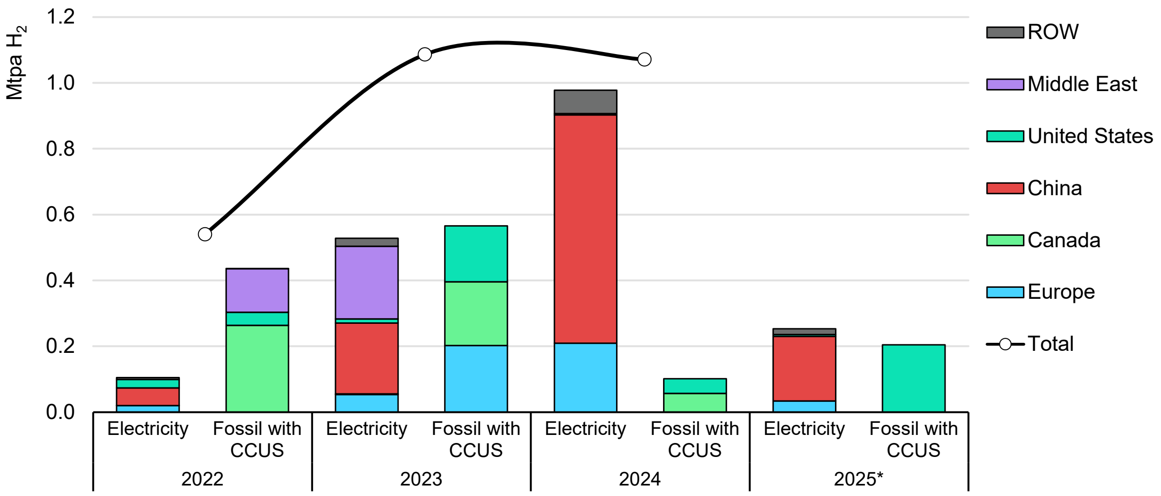
Regional patterns diverge by technology. Historical CCUS FIDs are concentrated in North America, making use of federal tax credits in the United States and Canada. In Europe, all CCUS FIDs took place in the Netherlands, where government schemes have underwritten projects. Historical electrolyser FIDs are

[31] This analysis excludes a large CCUS project of Air Products in Louisiana (United States) that had been included in previous GHRs on the basis that an FID was announced in 2023 (see previous footnote).

[32] This analysis excludes the largest project achieving FID in 2023 (NEOM Green Hydrogen Project 2.2 GW of electrolysis capacity) and in 2024 (AM Green project in Kakinada city, 1.3 GW), which completely skew the analysis.

dominated by China, which accounts for 60% of electrolyser FIDs over the past 3 years, driven largely by state-owned enterprises executing national renewable hydrogen plans. China's strong lead in electrolysis deployment is undeniable, but there have also been some setbacks to projects that had previously reached FID and were eventually cancelled. This demonstrates that not all the production at FID stage will become operational. However, given the pace of growth in FIDs in China, it seems likely that new FIDs will more than compensate for the cancellations in the country.

Figure 3.4 Low-emissions hydrogen production to reach final investment decision, 2022-2025H1



Notes: CCUS = carbon capture, utilisation and storage; ROW = rest of world. 2025* based on data up to July 2025.
Source: IEA Hydrogen Production Projects Database (September 2025).

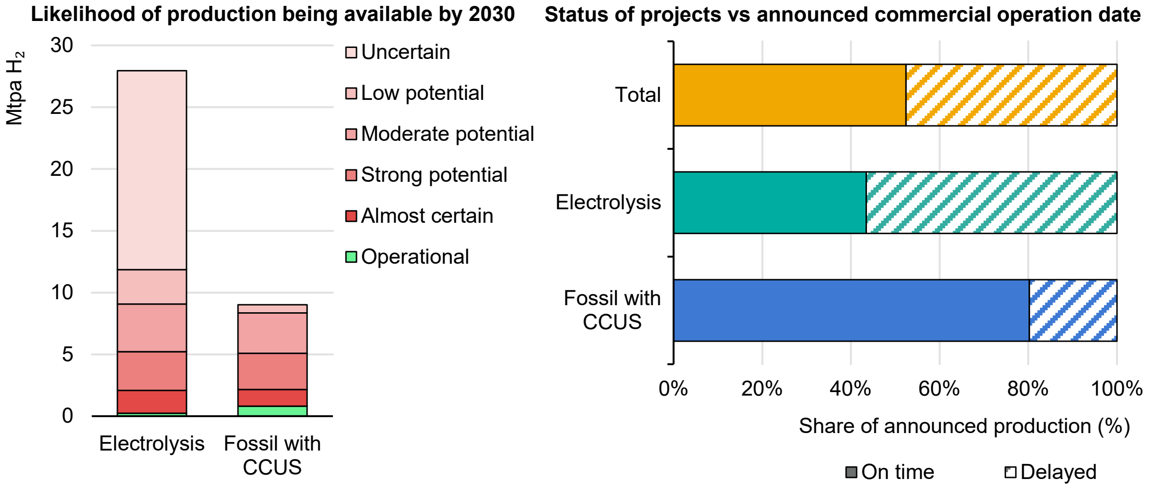
Investment decisions remained above 1 Mt in 2024, with a large increase in annual FIDs for electrolysis projects compensating a reduction in FIDs for CCUS projects.

Only a small fraction of the total project pipeline can realistically start operating by 2030, highlighting policy gaps

The potential low-emissions hydrogen production from announced projects that could be available by 2030 has declined compared to in GHR-24. With only 5 years to 2030, and taking into account typical development cycles, which stretch from 3 to 6 years, realising the full pipeline of projects would appear very difficult. In addition, we estimate that half of the announced project pipeline faces deferred start dates compared to the commercial operation date announced by developers. Delays are particularly acute among electrolyser projects, many of which had announced what were very ambitious timelines for a technology that had not been deployed at large scale before; in comparison, large-scale CCUS projects have been operating for several years. More than half of potential electrolyser capacity is now set to slip past target operational dates, while 20% of CCUS capacity is similarly deferred (Figure 3.5).

This delay in project delivery raises questions about the volume of low-emissions hydrogen production that can feasibly be in operation by 2030. To evaluate announced projects, we have developed a methodology based on the status, size, location and target end-use sector of the projects, in order to assess the likelihood for 2030 operation (Box 3.1). Projects that are under construction or at FID comprise more than 3 Mtpa of production that can be deemed almost certain (equalling more than 4 Mtpa when also considering operational projects). An additional 6 Mtpa has strong potential to be operative by 2030, but unlocking this volume will depend on closing the cost gap with unabated fossil fuel-based hydrogen through targeted subsidies, stimulating demand in existing industrial applications, and scaling up supporting infrastructure such as CO_2 transport and storage networks and hydrogen pipelines. A further 7 Mtpa has moderate potential but will require intensified policy efforts to secure offtake in emerging sectors (such as steelmaking, maritime shipping and aviation), and to provide concessional finance to projects under development in emerging markets and developing economies (EMDEs), where regulatory frameworks remain nascent and access to capital is particularly challenging.

Figure 3.5 Likelihood of production being available by 2030 and share of potential production that is on time according to the schedules announced by project developers, by technology



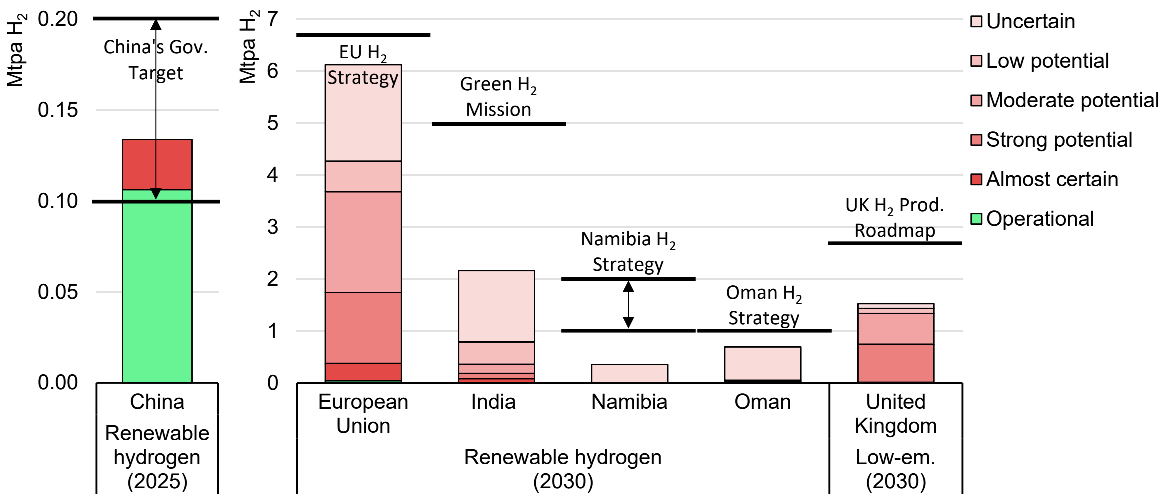
Notes: CCUS = carbon capture, utilisation and storage. More details about announced projects for low-emissions hydrogen production can be found in the new Hydrogen Tracker available on the IEA website.
Source: IEA Hydrogen Production Projects Database (September 2025).

Only around 10 Mtpa of low-emissions hydrogen production are almost certain or have strong potential to be operational by 2030.

However, more than half of the potential production in the pipeline has low potential or is uncertain to be operative by 2030. Almost half of these projects are very large electrolysis developments in EMDEs that may have access to low-cost renewable electricity but face high barriers to development due to a lack of regulatory readiness, of clear offtake frameworks and of reliable financing channels. Even with rapid improvements to these conditions, the sheer scale of some announced projects makes it unlikely they will be commissioned before 2030, meaning that realistic operational timelines stretch into 2035–2040.

This likelihood assessment also helps to evaluate the likelihood of achieving government targets. Based only on already operating projects, China has already reached the lower end of its target of producing 100–200 ktpa of renewable hydrogen by 2025 (Figure 3.6). The European Union's project pipeline could technically deliver around 6 Mtpa by 2030, which is lower than its [Hydrogen Strategy] target, and just under 2 Mtpa are operational, almost certain or have strong potential of being available by 2030. A similar situation can be observed in the United Kingdom, with a total pipeline that accounts for close to 60% of its target, but just around 25% having strong potential to be operative by 2030. Other countries with ambitious targets, such as India, Namibia and Oman, risk falling far short of their announced ambitions. In all these cases, projects that are operational, almost certain or have a very strong potential to be available by 2030 account for less than 20% of their target. With the right incentives and policy settings, market development can be accelerated, but the short time to 2030 makes the achievement of some stated ambitions very unlikely. This juncture calls for governments to recalibrate hydrogen production targets to align with sectoral maturity, at the same time as maintaining and strengthening regulatory frameworks, financial incentives and demand-creation measures, to ensure that anticipated low-emissions volumes materialise.

Figure 3.6 Low-emissions hydrogen production from announced projects compared with government targets for 2025 and 2030



Notes: Low-em. = low-emissions hydrogen. The EU Hydrogen strategy target is based on modelling results for the Fit-for-55 package. For the United Kingdom, the targets reflect low-emissions hydrogen, which includes both hydrogen produced from low-emissions electricity, from biomass, and from fossil fuels with CCUS..

Sources: IEA Hydrogen Production Projects Database (September 2025); Hydrogen Industry Development Plan (2021-2035); EU Hydrogen Strategy; India's Green Hydrogen Mission; Oman Green Hydrogen Strategy; Namibia Green Hydrogen and Derivatives Strategy; UK Hydrogen Production Delivery Roadmap.

The status of the project pipeline suggests that government targets for low-emissions hydrogen production by 2030 are unlikely to be met.

Box 3.1 Project methodology assessment

We have developed a methodology to assess the likelihood of the hydrogen projects with an announced operational date between 2026 and 2030 becoming operational by 2030. This is based on the following key deliverability parameters:

- *Size factor*: electrolysis projects were divided into four groups based on their size (≤200 MW, 200 MW-1 GW, 1-2.5 GW, >2.5 GW), with the likelihood of becoming operational decreasing as the size increases. The ranges for the groups were selected based on a common size for projects reaching FID today (200 MW), the size of the largest projects taking FID (1 GW), and the size of the single largest project that could be delivered by 2030 if FID were to be reached this year (2.5 GW), based on the size (2.2 GW) and the lead time (~4 years) of the largest project currently under construction. For CCUS, the size of projects was not factored into the likelihood assessment, given that announced CCUS projects span a much narrower range of scale than electrolysis projects. For projects with multiple phases, each phase is assessed individually as a single project.
- *End-use factor:* all projects were classified into four groups based on their announced target end-uses. The projects classed as having a higher likelihood are those that already have an off-taker or that are targeting existing hydrogen applications, whereas the projects with a lower likelihood are merchant hydrogen projects without a clearly defined target end-user, or trade-related projects that do not target already globally traded commodities (e.g. ammonia for fertiliser production).
- *Regional factors:* countries have been assessed according to a series of indicators and enabling factors that can influence the likelihood of a project being delivered. A total of 30 indicators were identified and grouped under 6 enabling factors: ease of doing business, industrial competitiveness, financing costs, energy infrastructure, access to low-emissions energy and status of hydrogen market. This expands on the list of indicators used in the IEA's Energy Technologies Perspectives 2024 to assess the attractiveness of countries for investment in clean energy technology manufacturing by incorporating indicators that are specific to the hydrogen sector. A detailed description of the enabling factors, the indicators and their distribution across technologies is provided in the annex, along with a methodology used to distribute countries in four groups according to their likelihood to host low-emissions hydrogen production projects.

Based on the status of the projects and the factors previously described, we have determined the likelihood of projects being realised by categorising them as almost certain, strong potential, moderate potential, low potential and uncertain. For example, projects with an FID have been categorised as almost certain, whereas multi-GW projects at very early stages of development without identified potential offtakers in countries with weak enabling factors have been categorised as uncertain.

This assessment should be interpreted as an indication, not a definitive judgement. The analysis reflects each project's current status based on a range of diverse factors. Project and market conditions evolve, however, and so scores may shift, highlighting the importance of ongoing monitoring and reassessment.

Persistent barriers to final investment decisions in hydrogen production projects are causing delays and cancellations

For investors and project developers, technical, regulatory and financial obstacles, as well as difficulties in securing reliable offtake agreements, continue to slow down or even completely stall project progress.

The broader economic context – marked by high inflation and increased uncertainty – has led many companies to reduce, delay or suspend investment plans. ArcelorMittal, for example, has paused key direct reduced iron (DRI) projects in Europe despite having secured public subsidies, citing weak demand and regulatory barriers. Regulatory challenges often include unclear, complex or evolving definitions of low-emissions hydrogen, lack of harmonised certification schemes, and slow, complex permitting procedures. Several oil and gas majors have taken a step back in their plans to transition to clean energy technologies, which have, of course, impacted hydrogen. For example, BP has restructured its hydrogen strategy to focus on a smaller number of high-certainty projects, and Japan's ENEOS Holdings has similarly scaled back its hydrogen ambitions, delaying its targets and prioritising investments in liquefied natural gas (LNG) and conventional oil assets.

Given the current cost gap between unabated fossil-based hydrogen production and low-emissions production, supportive policies and funding remain essential to aid project development. However, developers frequently face long delays and uncertainty regarding eligibility, implementation timelines, and disbursement of funds. In some cases, the roll-out of announced support schemes has been paused or delayed, as seen with the temporary suspension of the IRA in the United States. In the United Kingdom, stakeholders have expressed concern over the lack of implementation timelines, despite the presence of well-designed policy frameworks. Developers have highlighted that the project delivery deadlines set by support mechanisms, such as those under the EU Hydrogen Bank, are difficult to meet, increasing the risk of losing support if commissioning is delayed. In Queensland, Australia, the CQ-H2 project was shortlisted in the first round of the

Hydrogen HeadStart programme, but the state government decided not to provide further funding. Stanwell, the lead developer, has discontinued its involvement in the project.

Regulatory uncertainty in key markets further complicates the investment landscape. A recent example is the postponement of EWE's 50 MW electrolysis project in Bremen (Germany) due to regulatory barriers at both national and EU level, despite having secured public funding to cover around two-thirds of the total investment cost. The definitions and eligibility criteria for support schemes continue to evolve, and political transitions can lead to abrupt shifts in support. For instance, some countries, such as Germany, have called for a relaxation of the EU Renewable Fuels of Non-Biological Origin (RFNBO) rules, citing concerns that overly strict requirements could limit project viability and delay investment. This regulatory uncertainty is further compounded by the fact that the full regulatory framework for low-emissions hydrogen production, including the delegated act setting the methodology for "low carbon" hydrogen,[33] is still pending final approval from the European Parliament (expected in mid- 2025). Whether due to policy changes or administrative complexity, this type of instability continues to affect project developers' ability to plan and invest with confidence.

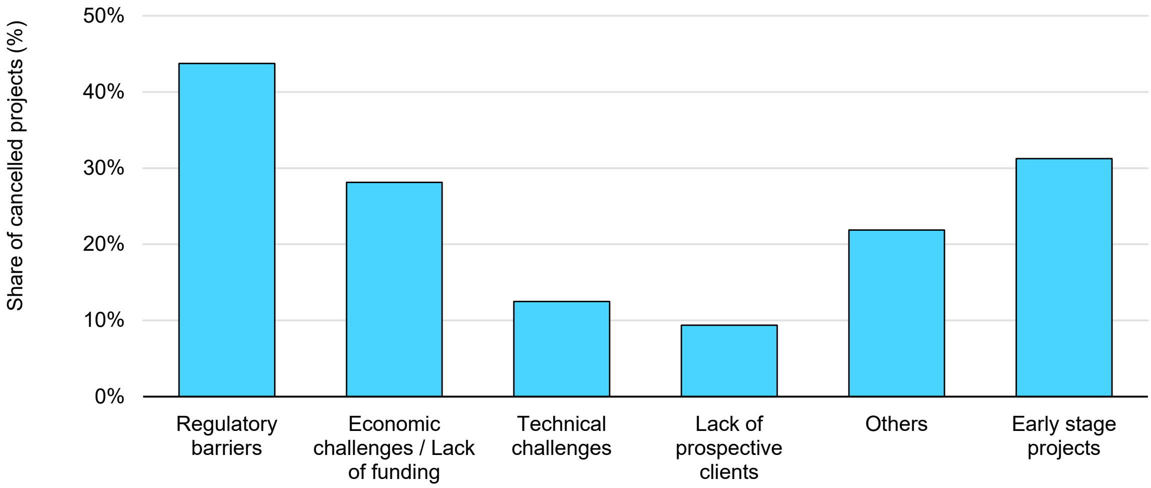
While there is consensus that hydrogen can play an important role in global decarbonisation and enhancing energy security, market demand is not yet mature enough to provide long-term stability and a reliable basis for large-scale investments. Many projects struggle to secure creditworthy offtake agreements that meet the requirements of financiers and investors. Intentions to purchase low-emissions hydrogen are frequently announced, but few result in firm, long-term contracts with bankable prices and volume. For instance, Saudi Aramco announced in March 2025 the reduction of its 2030 target to produce ammonia from fossil fuels with CCUS (from 11 Mtpa to 2.5 Mtpa) due to a lack of offtake agreements. Similarly, Orsted's FlagshipONE project in Sweden was cancelled after FID due to a lack of long-term offtake contracts. Firm offtake agreements account for only 5% of the 37 Mtpa of the potential production of low-emissions hydrogen from announced projects (see Chapter 2 Hydrogen demand). This highlights the need to implement more ambitious policies to stimulate demand more effectively and facilitate offtake agreements. For example, in the European Union, despite the adoption of binding targets for use of RFNBOs in industry and transport under the Renewable Energy Directive (RED), future demand for renewable hydrogen remains uncertain due to the delay in transposition into national legislation in most EU member states, leading to slow market uptake. Ensuring timely and co-ordinated implementation of such frameworks will be important to support investment and build confidence.

[33] See Explanatory notes annex regarding the use of the term "low-carbon" hydrogen in this report.

In parallel, as projects scale from pilots to commercial operation, the need for mature and reliable production technologies becomes increasingly important. Developers are no longer focused solely on efficiency or innovation – they require industrial partners capable of guaranteeing long-term performance, delivery timelines and maintenance. However, several electrolyser manufacturers are currently facing insolvency or scaling back operations (see Electrolyser manufacturing for more details), which undermines confidence in the supply chain. This creates risks both during project delivery and subsequent operation. The engineering design of a plant is technology-specific, meaning that the loss of a selected electrolyser manufacturer could require a complete re-engineering of the project, impacting cost and lead time. Developers also fear not being able to get technical support over the economic lifetime of the plant. Government-backed counter-guarantees for advance payment or performance guarantees can help mitigate these risks (see Chapter 5 Investment and innovation).

In response to these challenges, companies are adopting a more selective approach. The enthusiasm observed during 2020-2022 has given way to strategic consolidation. Firms are prioritising projects with clear internal synergies or direct links to their own decarbonisation goals, as seen at Johnson Matthey.

Figure 3.7 Share of cancelled hydrogen projects by reason for cancellation



Notes: A total of 32 projects with available information on the reasons for their cancellation are included. Each project may cite more than one barrier as contributing to its cancellation. Categories reflect self-reported reasons from project developers or official announcements. "Early-stage projects" refer to projects that were cancelled at early stages of development, some without stating publicly a reason for the cancellation and others also citing one of the other reasons shown in the chart.

Sources: IEA analysis based on the IEA Hydrogen Production Projects Database (September 2025), announcements by project developers and personal communications.

Most projects cancelled were at very early stages of development, but even more advanced projects are struggling with regulations and gaps or delays in support schemes.

A closer look at the hydrogen production projects that have been cancelled reveals that specific barriers such as regulatory and permitting issues (44%), economic challenges (28%), technical difficulties (13%), and lack of prospective clients (9%) were frequently cited as reasons for cancellation. In addition, a notable 31% of cancellations correspond to projects that were cancelled at early stages of development that often referred to overambitious assumptions on cost reductions or premature expectations of market development as key reasons for cancellation (Figure 3.7). These figures highlight how the initial wave of announcements often lacked alignment with real market and policy conditions, reinforcing the notion that the sector is now consolidating around more mature projects with solid business cases. Projects of this kind combine technical maturity, commercial realism and alignment with government ambitions for decarbonisation and enhancement of energy security, but they will still need policy support to materialise.

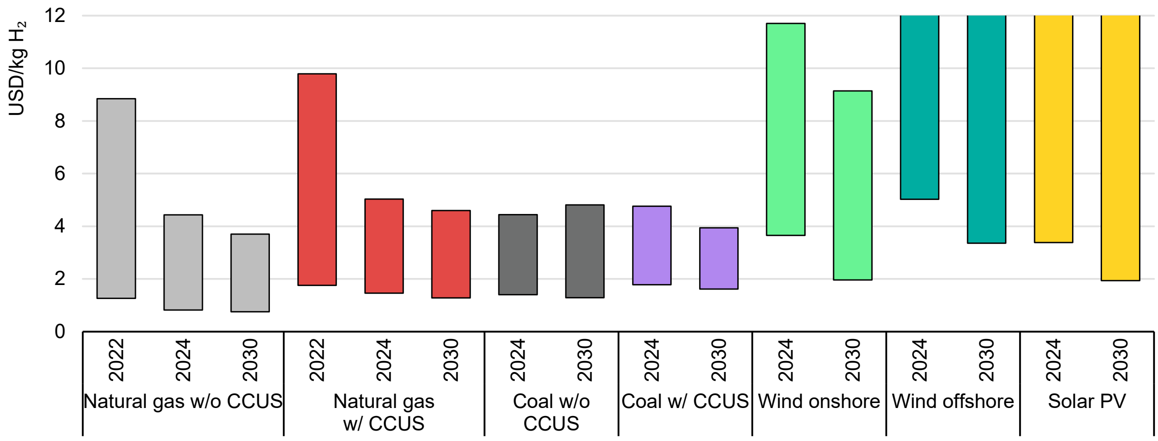
Cost comparison of different production routes

Low-emissions hydrogen production to remain more costly than unabated fossil-based routes in most regions in the mid-term

Hydrogen production continues to be dominated by unabated fossil fuel routes, which still have a cost advantage over low-emissions hydrogen production routes. This situation was briefly challenged in 2022, when the price of fossil fuels (particularly natural gas) steeply increased in several regions of the world as a consequence of the geopolitical and energy turmoil following Russia's full-scale invasion of Ukraine. During this time, the levelised cost of hydrogen (LCOH) production from unabated natural gas ranged from just above USD 1/kg H_2 (nearly USD 2/kg H_2 in the case of natural gas with CCUS) in some natural gas-producing regions, to values close to USD 9/kg H_2 in natural gas-importing regions (Figure 3.8). In this situation, the cost of production of hydrogen from renewable electricity (which then ranged from slightly less than USD 4/kg H_2 in locations with strong renewable resources to more than USD 10/kg H_2 in locations with less potential) became competitive in some regions, but replacing unabated fossil fuel production was not readily achievable.

However, this situation did not last: natural gas prices have declined sharply in the past 2 years, although in regions such as Europe and Asia, they remained at around twice their historical average in 2024. As a consequence, in 2024, the cost range for the production of hydrogen from unabated fossil natural gas decreased to USD 0.8-4.6/kg H_2. In contrast with this, the cost of equipment for the production of renewable hydrogen has increased in recent years due to inflation and the slower-than-expected deployment of the technology. This means that the lower boundary cost for hydrogen from renewable electricity in 2024, achieved in China, was broadly aligned with the upper range limit for unabated natural gas, achieved in regions like Korea and the European Union. China can count on an important advantage with lower electricity prices (coming from lower capital expenditures [CAPEX] and cost of capital for renewables) and lower CAPEX for electrolysers, despite issues with efficiency and underperformance of Chinese electrolysers (see Electrolysis). This production route would therefore not have been cost-competitive anywhere in the world, even if production capacities had been available.

Figure 3.8 Hydrogen production cost by pathway, 2024, and in the Stated Policies Scenario, 2030



Notes: CCUS = carbon capture, utilisation and storage; w/ = with; w/o = without. Cost ranges reflect regional differences in fossil fuel prices, renewable costs, CO_2 prices, technology CAPEX and OPEX as well as cost of capital. Natural gas price is USD 5.7-50/MBtu for 2022, USD 1.7-25/MBtu for 2024 and USD 1.6-21/MBtu in the Stated Policies Scenario (STEPS) in 2030. Coal price is USD 21-260/t for 2024 and USD 22-200/t for the STEPS in 2030. CO_2 price is USD 0-90/t CO_2 for 2022, USD 0-70/t CO_2 for 2024 and USD 0-106/t CO_2 for the STEPS in 2030. The levelised production cost of solar PV electricity is USD 20-110/MWh for 2024 and USD 13-85/MWh for the STEPS in 2030, with a capacity factor of 12-35%. The levelised production cost of onshore wind electricity is USD 25-100/MWh for 2024, USD 23-90/MWh for the STEPS in 2030, with a capacity factor of 30-53%. The offshore wind electricity levelised production cost is USD 52-270/MWh for 2024, USD 40-165/MWh for the STEPS in 2030, with a capacity factor of 30-67%. For China, electrolyser CAPEX is USD 900/kW in 2024 and USD 675/kW for the STEPS in 2030, whereas for the rest of the world, it is USD 2 300/kW in 2024 and USD 1 600/kW for the STEPS in 2030. Electrolyser CAPEX includes the electrolyser system, balance of plant, engineering, procurement and construction (EPC) and contingencies; electrolyser capacity factor is assumed to be the same as the renewable power plant. The cost of capital is 6-20%. Figure capped at USD 12/kg H_2, although some production routes reach higher values. Water cost is not included. More details on the cost of producing low-emissions hydrogen using different technologies and in different regions can be found in the new Hydrogen Tracker available on the IEA website.

Sources: IEA analysis based on data collected through a survey to original equipment manufacturers, EPC companies and project developers, data from McKinsey & Company and the Hydrogen Council; BloombergNEF, Argus Media Group, All rights reserved, NETL (2022); IEA GHG (2017).

The recent drop in fossil fuel prices has increased the cost gap between low-emissions hydrogen production and unabated fossil-based routes.

As such, it is clear that the use of supportive policies to close the cost gap with unabated fossil-based production will remain necessary if countries want to kick-start large production of renewable hydrogen, and thus drive cost reductions from economies of scale and learning-by-doing. This is particularly important for countries that are highly dependent on fossil fuel imports, since renewable hydrogen can both support achievement of decarbonisation goals and hedge against price volatility, thereby improving energy security.

Under today's policy settings, this situation may change slightly by 2030. In the IEA's Stated Policies Scenario (STEPS), the production of hydrogen from natural gas without CCUS remains in the range of USD 0.7-3.7/kg H_2 in 2030. There is a larger drop at the higher end of the cost range, since natural gas demand is often already lower in regions where natural gas prices are higher, due to efforts to reduce dependency on fossil fuels. This limits the potential for a robust demand response to the larger LNG supplies becoming available by 2030, thus pushing natural gas prices down. However, this drop is partially compensated by an increase in carbon prices. In the case of renewable hydrogen, the large-scale deployment of electrolysers leads to technology cost reductions, combined with the continued decrease in the cost of variable renewables, lead to a reduction of the cost of producing renewable hydrogen. This brings the lower end of the cost range close to under USD 2/kg in the case of China. Other regions with ample renewable potential and a low cost of capital, such as Australia, Chile, Brazil, the Middle East or the United States, can reach values in the range of USD 3-4/kg H_2.

Beyond the production costs, the key driver of offtake is the price of hydrogen, which differs from production costs since it includes other additional costs and factors (Box 3.2).

Box 3.2 The differences between hydrogen production cost, price index and market price

In the context of low-emissions hydrogen development, it is essential to distinguish between the concepts of production cost, price index and market price, which all refer to very different economic realities.

Hydrogen production cost

The production cost refers to the total expenditure incurred to produce one unit of hydrogen, typically expressed in monetary values per kg of hydrogen (e.g. USD/kg H_2 or EUR/kg H_2). In the case of hydrogen produced in electrolysers running on low-emissions electricity, this cost mainly depends on the price of electricity, the CAPEX, the cost of capital and the efficiency of the electrolyser and its utilisation rate. In the case of hydrogen produced from fossil fuels with CCUS, the production cost is largely dominated by the costs of the fuel input and the CO_2 prices. This is a theoretical value that does not account for commercial margins and does not reflect actual market behaviour.

Price indexes

Price indexes are indicative references of hydrogen's theoretical market value, based on various assumptions. While they may not reflect actual transactions, they provide useful signals for regulators, investors and market participants. Assumptions such as electricity prices, technological configurations, or financial parameters can influence their robustness and limit comparability across indexes. Notable initiatives include:

- The HYDRIX index, the first renewable hydrogen price index published in Europe, developed by the European Energy Exchange with the H2Global Foundation. HYDRIX does not reflect actual transaction prices but is based on indicative prices voluntarily submitted by market participants. Contributors report a single average buy and/or sell price, expressed in EUR/MWh. Only data aligned with the index's specification (hydrogen produced via electrolysis from renewable electricity) are accepted. The index is calculated as an arithmetic average of all qualifying submissions, provided that at least five contributors each submit four valid data points. If this condition is not met, the index is based on the average of the previous three weeks, or may go unpublished.
- The IBHYX index, developed by MIBGAS, reflects the production cost of renewable hydrogen in the Iberian Peninsula. It is the outcome of a technical working group composed of key stakeholders across the hydrogen value chain in Spain and Portugal. The group defined a model plant, representative of a renewable hydrogen production project aligned with EU regulations. IBHYX represents the minimum price at which a producer would be willing to sell hydrogen to recover costs and earn a return. Its methodology is based on a project finance model that goes beyond the traditional LCOH approach, incorporating separate return expectations for equity and debt and key investment variables. The price is derived through an iterative process that ensures financial balance over the project's life. The index is published weekly.
- The GreenHydrogen index, developed by the Central European Gas Hub, estimates the LCOH of renewable hydrogen in Austria. It is based on a model electrolysis plant connected to a renewable energy source, using standardised technical and financial parameters. The calculation incorporates the average hourly price of renewable electricity from the European Power Exchange (EPEX) Spot market, along with investment costs, operating expenditure (OPEX), and system efficiency. The index is expressed in EUR/MWh and published every Tuesday.
- The HYCLICX index, developed by HyXchange, estimates the variable production cost of renewable hydrogen from electrolysis in the Netherlands. The index links the hydrogen price to the hourly electricity spot market and incorporates costs related to electricity consumption, renewable electricity

guarantees, and operational expenses. It is published monthly in EUR/MWh, based on the Higher Heating Value (HHV) of hydrogen.

In addition to these initiatives, some consulting companies and data providers have developed hydrogen price indexes in other regions of the world. An example is S&P Global, which offers daily price assessments for various production pathways in North America (United States and Canada) and Asia (Japan) through Platts. The assessments include hydrogen produced through steam methane reforming (SMR) with and without carbon capture and storage, alkaline electrolysis and proton exchange membrane (PEM) electrolysis.

Market price

The market price refers to the actual value at which a good is exchanged in a commercial transaction between two parties. In mature markets, this price results from the balance of supply and demand, reflecting a liquid market with multiple buyers and sellers. In the case of low-emissions hydrogen, such a market has not yet been developed, so it is not possible, strictly speaking, to refer to a market price. The limited transactions that do occur are typically linked to pilot projects, confidential bilateral agreements, or publicly supported schemes, and are insufficient to establish a representative price reference.

Moreover, hydrogen market prices are strongly shaped by regulatory frameworks, which define eligibility and influence demand. For instance, in some jurisdictions, only hydrogen meeting specific sustainability criteria qualifies for public support or market incentives. In the European Union, for example, only renewable hydrogen classified as a RFNBO qualifies for certain support schemes, and EU legislation distinguishes between renewable and “low-carbon” hydrogen.* These definitions could lead to differentiated demand and segmented price signals based on compliance with specific classifications.

A clear understanding of these concepts is essential to avoid misinterpretation and to assess hydrogen market development rigorously in the coming years.

* See explanatory notes annex regarding the use of the term “low-carbon” hydrogen in this report.

The cost gap varies significantly across regions, and some are ready to close the gap by 2030

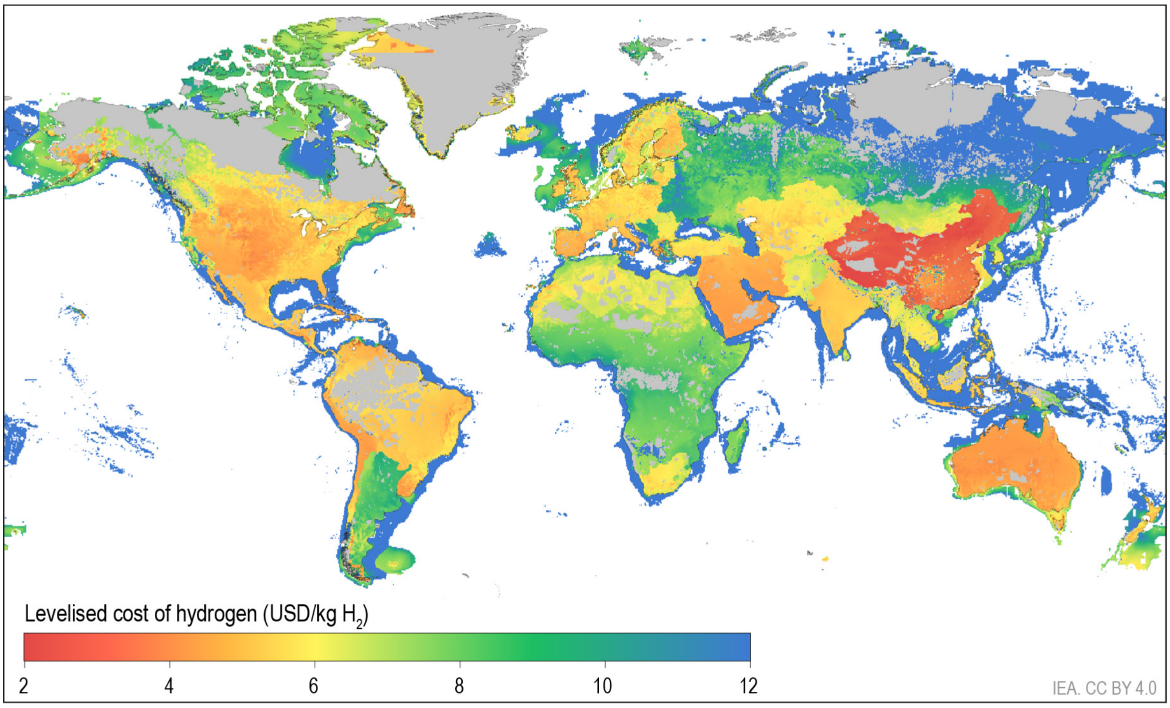
The global ranges of hydrogen production cost give an indication of how technology cost can evolve over time, but do not enable a deep assessment of the competitiveness of different technology routes, which is strongly dependent on regional conditions.

The cost of production of low-emissions hydrogen from renewable electricity depends primarily on the cost of the renewable electricity, which is ultimately related to the renewable energy resources of each region. However, other factors such as the cost of installing electrolysers (including CAPEX of the electrolyser, BoP and engineering, procurement and construction [EPC]) or the cost of capital for the development of the project, which can also vary across different regions (see Electrolysis section for more details), can strongly impact the cost of producing renewable hydrogen. In the STEPS, certain regions in China (that combine very low costs for electrolysis technology and installation, a low cost of capital and strong renewable resources), the Middle East (with a very low cost of capital and large renewable potential) and Australia and some areas of the United States (both benefitting from a low cost of capital and large renewable potential) can reduce the cost of producing renewable hydrogen down to USD 2-4/kg H_2 (Figure 3.9).

The cost of producing hydrogen from fossil fuels (either unabated or with CCUS) also varies regionally. Gas-producing regions like the United States or the Middle East have a competitive advantage due to their lower natural gas prices. On the other hand, regions like China and Europe, which depend on imports to meet natural gas demand, face higher natural gas prices. In the case of China, the combination of large coal reserves with low prices has historically led the country to move away from using natural gas for hydrogen production and to use coal instead (60% of domestic hydrogen production). In the case of Europe, the existing production capacity was developed when regional gas reserves were available, or demand could be met with low-cost imported natural gas. However, the combination of decarbonisation goals and growing concerns about the energy security risks of dependence on imported natural gas are now steering the region to replace existing production with renewable-based domestic production.

These cost variations will determine when low-emissions hydrogen production routes will become competitive in each region, as well as the cost gap that would need to be covered by policy action in the interim period until these technologies can be deployed at scale without the need for policy intervention. In the case of renewable hydrogen, the cost gap with the incumbent technology is large in all regions, although there are significant differences. For example, in China, producing hydrogen with unabated coal is more than USD 1.5/kg H_2 cheaper than using the best conditions for renewable electricity, whereas the cost gap with the use of unabated natural gas is more than USD 4/kg H_2 in the case of the United States, and USD 6/kg H_2 in the Middle East (Figure 3.10).

Figure 3.9 Hydrogen production cost from electrolysis using hybrid solar PV and onshore wind, and from offshore wind, in the Stated Policies Scenario, 2030



Notes: Assuming optimal oversizing of the renewable plant in each location to minimise the levelised cost of hydrogen production. Solar PV CAPEX is USD 400-1 250/kW, Onshore Wind CAPEX is USD 950-2 300/kW, Offshore Wind CAPEX is USD 1 720-4 850/kW. The cost of capital is assumed to be between 6-20% across different locations in this map. Water cost is not included. More details on the cost of producing low-emissions hydrogen using different technologies and in different regions can be found in the new Hydrogen Tracker available on the IEA website.

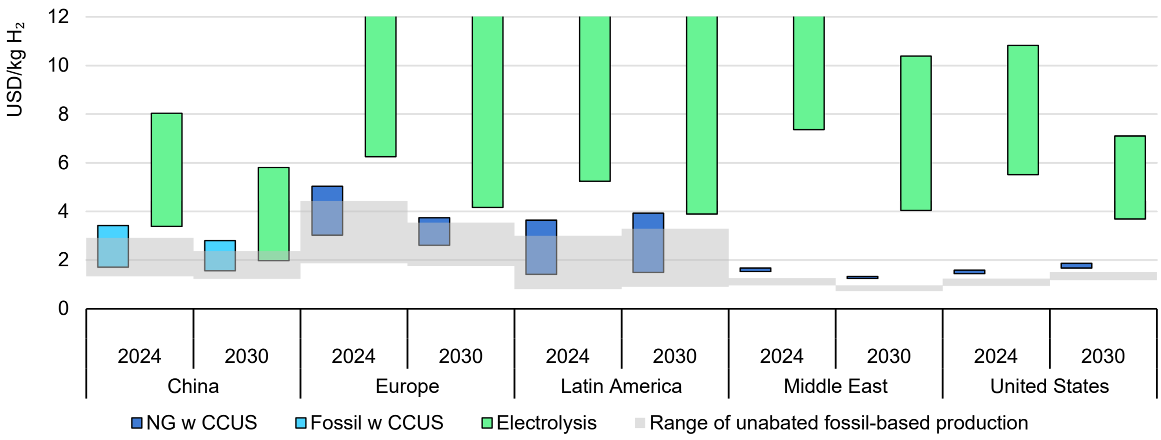
Source: Analysis by Jülich Systems Analysis at Forschungszentrum Jülich using the ETHOS model suite.

Regions with large renewable resources and low costs for electrolysers and renewable energy technologies, plus a low cost of capital, could achieve competitive production of renewable hydrogen by 2030.

In the coming years, the continued decline in the cost of renewable energy technologies, and the potential drop in electrolysis costs resulting from larger deployment, improved technology integration and manufacturing and technology innovation, is expected to narrow the cost gap. Some regions are well placed to close the gap entirely. By 2030, in the STEPS, the cost of producing hydrogen using optimal conditions for renewable electricity generation in China is within the range of producing hydrogen from unabated fossil fuels. In other regions, although renewable hydrogen does not reach competitiveness with unabated fossil-based generation, the cost gap narrows significantly. For example, in some areas of Latin America the cost gap in 2030 could be reduced to just above USD 0.5/kg H_2, same as in some areas of Europe (assuming that CO_2 prices reach more than USD 100/t CO_2). However, although the cost gap is reduced across all the regions considered, in some cases it remains high, at more than USD 2/kg H_2 in the

United States and around USD 3/kg H_2 in the Middle East. Closing the cost gap in these cases will require the implementation of CO_2 prices close to USD 200/t CO_2 and USD 270/t CO_2 respectively.

Figure 3.10 Hydrogen production cost by pathway and region in the Stated Policies Scenario, 2024-2030



INotes: NG = natural gas; CCUS = carbon capture, utilisation and storage. Natural gas price is USD 2.5-25/MBtu for 2024 and USD 1.8-18/MBtu for 2030. Coal price is USD 80-100/t for 2024 and USD 65-80/t for 2030. CO_2 price is USD 0-70/t CO_2 for 2024 and USD 0-106/t CO_2 for 2030. Solar PV CAPEX is USD 600-1 000/kW for 2024 and USD 400-700/kW for 2030, Onshore Wind CAPEX is USD 1050-1 950/kW for 2024 USD 950-1 750/kW for 2030, Offshore Wind CAPEX is USD 2 400-4 900/kW for 2024 and USD 1 720-3 3800/kW for 2030. For China, electrolyser CAPEX is USD 900/kW in 2024 and USD 675/kW in 2030, whereas for the rest of the world, it is USD 2 300/kW in 2024 and USD 1 600/kW in 2030. Electrolyser CAPEX includes the electrolyser system, balance of plant, engineering, procurement and construction (EPC) and contingencies. The cost of capital is 6-18%. The grey shades represent the range of production costs for routes using unabated fossil fuels in each of the regions assessed. The ranges of the fossil-based routes for China include both natural gas reforming and coal gasification. Figure capped at USD 12/kg H_2, although some production routes reach higher values. Water cost is not included. More details on the cost of producing low-emissions hydrogen using different technologies and in different regions can be found in the new Hydrogen Tracker available on the IEA website.

Sources: IEA analysis based on data collected through a survey to original equipment manufacturers, EPC companies and project developers, data from McKinsey & Company and the Hydrogen Council; BloombergNEF, Argus Media Group, All rights reserved, NETL (2022); IEA GHG (2017)

In regions that currently depend on imports and face high natural gas prices, renewable hydrogen production could become competitive by 2030 with the right policy incentives.

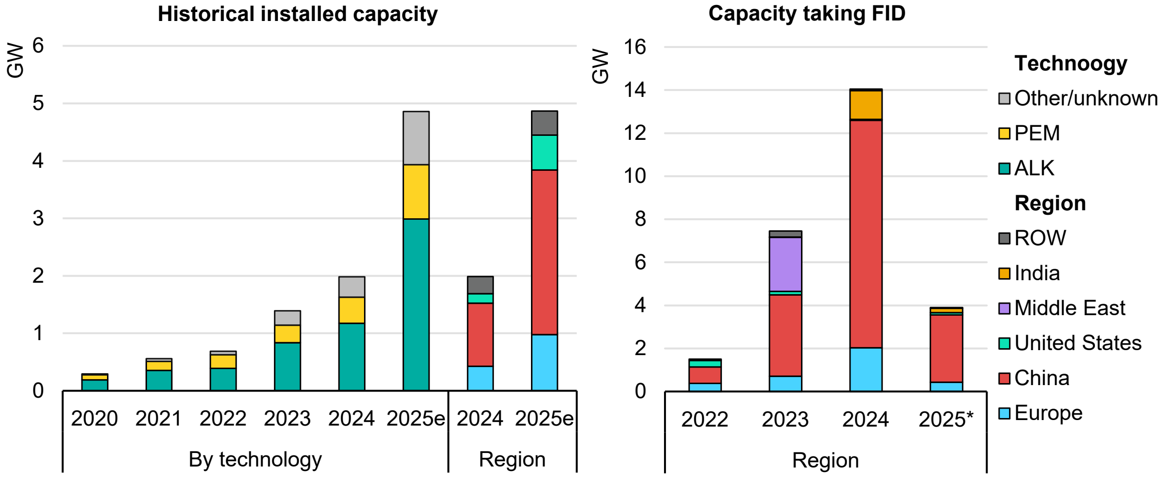
Electrolysis

Electrolyser deployment

Capacity additions slowed in 2024, but will grow again in 2025

The total installed capacity of water electrolysis reached almost 2 GW at the end of 2024 (Figure 3.11), despite a slight slowdown in annual capacity additions (around 600 MW) compared to 2023 (700 MW). Once again, the largest deployment took place in China (50%), which accounted for more than half of the global installed capacity of water electrolysis at the end of 2024. Europe saw the second-largest deployment, accounting for 25% of capacity additions and more than 20% of global installed capacity at the end of the year. In the European Union, installed capacity reached around 340 MW, significantly less than the interim target of 6 GW by 2024 adopted in the EU Hydrogen Strategy. Alkaline remains the leading technology, with 60% of the additions and the global installed capacity.

Figure 3.11 Installed electrolyser capacity by technology and region, 2020-2025e, and capacity reaching final investment decision by region, 2022-2025



Notes: ALK = alkaline electrolysers; PEM = proton exchange membrane electrolysers; FID = final investment decision. In this figure, FID includes projects under construction; ROW = rest of the world. “Other/unknown” technology includes solid oxide electrolysis, anion exchange membrane electrolysis, other novel designs, projects considering combining different technologies and projects for which the technology used is not known. The unit is GW of electrical input. Left hand figure: 2025e = estimate for 2025 capacity, based on projects planned to start operations in 2025 and that have at least reached FID. Right hand figure: 2025* based on data up to July 2025.
Source: IEA Hydrogen Production Projects Database (September 2025).

Global installed water electrolysis capacity reached 2 GW in 2024 and deployment is expected to accelerate in the near term, mainly due to developments in China.

The slowdown observed in 2024 will be reversed in 2025. More than to 1 GW had already been added by the end of July 2025, including what is now the world’s largest electrolysis plant (500 MW), commissioned by Envision in Chifeng (China) in July. Up to nearly 3 GW of capacity could be installed based on projects that have at least taken FID and have a target commercial operational date in this year. This growth is concentrated in China, with more than 30 projects aiming to start operation this year, accounting for close to 2 GW.

Based on the projects that have at least reached FID, faster deployment can be expected in the coming years. At the time of writing, 26 GW of electrolysis capacity had taken FID or was under construction with the target of being in operation by 2030. This is 12 times larger than all historical deployments at the end of 2024. There has been a significant acceleration in FIDs in the last 2 years, from less than 2 GW reaching FID in 2022, to 14 GW in 2024. China has been the main driver, thanks to a push from state-owned enterprises implementing government plans to reduce dependence on imported gas and stimulate manufacturing of electrolysers, building on the expertise of its industrial sector in mass-manufacturing clean energy technologies. Europe, with close to 3 GW, is the second-largest market, followed by the Middle East (2.5 GW) and India (more than 1 GW). In the case of the Middle East and India, the large capacity that has reached FID is concentrated in two projects – the largest to have reached financial closure in the world (NEOM in Saudi Arabia, 2.2 GW, and AM Green in India, 1.3 GW). In the case of Europe, capacity is distributed across around 50 projects of small to medium size, with the largest development being the Stegra DRI project in Sweden (740 MW).

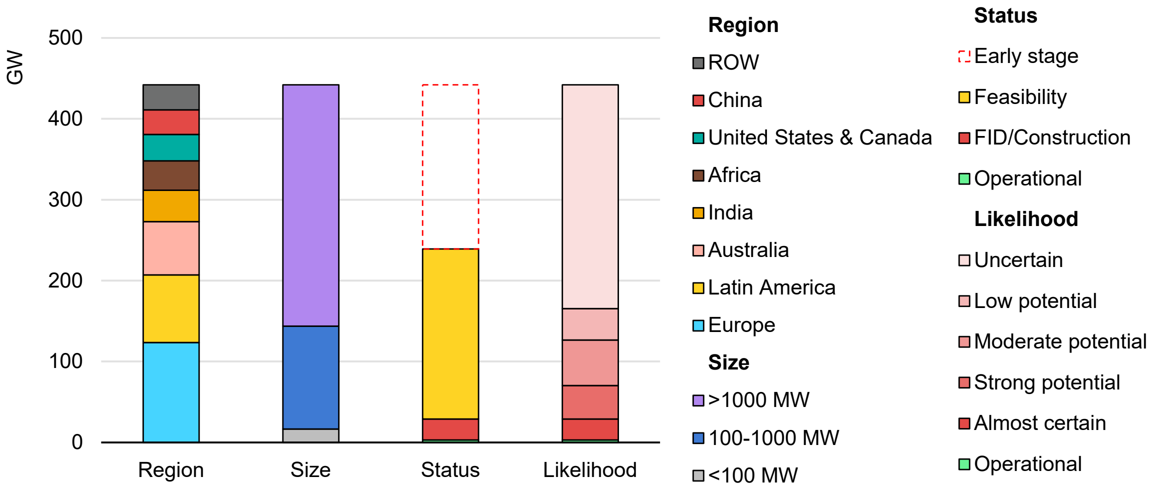
However, the growing trend in projects reaching FID every year seems to have slowed down in 2025, with 4 GW having reached that stage by the end of July, creating uncertainty about pace of deployment of the technology in the medium and long term. The biggest decrease was seen in China, although the number of projects reaching FID is expected to increase again in the coming years thanks to a new programme launched in June 2025 by the National Energy Administration. This will support the development of large-scale (>100 MW) projects for the production of hydrogen from renewable electricity. In Europe, there has been a significant deceleration compared with 2024 (only 12 projects reached FID between the start of the year and the end of July 2025, 9 of which are smaller than 25 MW), which may be a result of regulatory uncertainty in the region, particularly due to the transposition of RED targets into national legislation (see Chapter 6 Policies). In the United States, only the Roadrunner project for the production of synthetic fuels (which has secured a 10-year offtake agreement with AIG), has taken FID this year. Project developers paused their plans awaiting a decision on the future availability of the 45V tax credits, which were finally approved in July 2025. The tax credit, critical for project bankability, will remain available for projects that start construction before January 1, 2028, which is expected to lead to more FIDs in the near term.

Electrolysis capacity will grow significantly to 2030, but only a small fraction of all announcements are expected to be realised

The pipeline of announced electrolyser projects has decreased over the course of the past year due to projects being delayed, put on hold or cancelled (see Low-emissions hydrogen production could reach 37 Mtpa by 2030, but this volume has shrunk since last year). Based on announced projects, around 440 GW of capacity targets operation by 2030 or before, compared with the assessment from GHR-24 (520 GW) (Figure 3.12). Europe still accounts from the largest share of announced projects (more than 25%), followed by Latin America (close to 20%) and Australia (15%).

However, just 6% of the announced capacity has taken FID and nearly half is still at very early stages of development. In addition, two-thirds of the announced capacity is concentrated in projects of more than 1 GW of capacity. With only 5 years available for the development of these projects until 2030, the achievement of 440 GW (more than 200 times larger than historical deployments and almost 100 times larger than the maximum capacity that could be operative this year) seems out of reach. Our likelihood assessment indicates that 65 GW of capacity is almost certain or has strong potential to be operative by 2030 (or more than 70 GW if already operational capacity is also taken into account), but more than 300 GW (more than two-thirds of the announcements) has low potential or is uncertain to be operative by 2030.

Figure 3.12 Installed electrolyser capacity based on announced projects, 2030

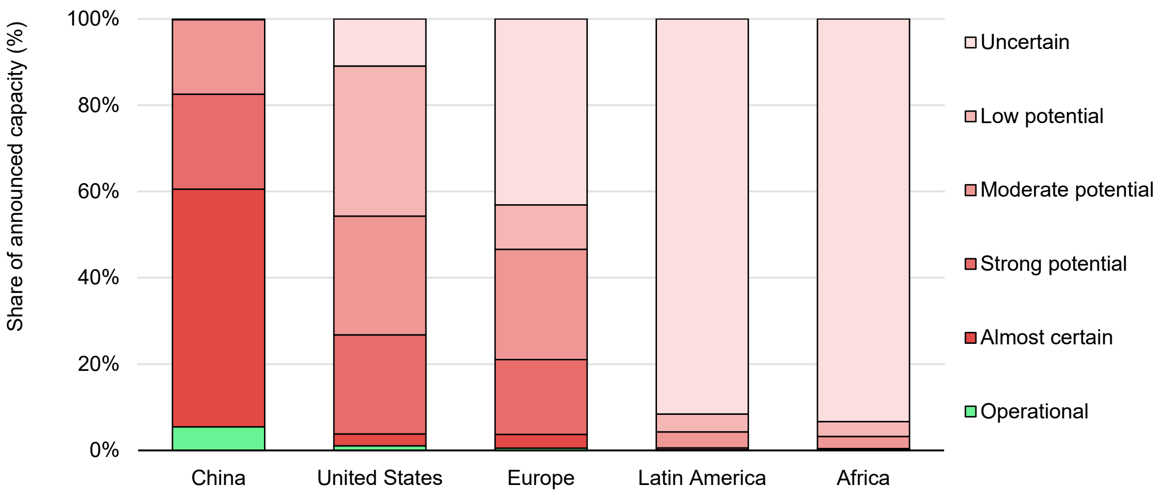


Notes: FID/Construction = final investment decision and under construction; ROW = rest of the world. The unit is GW of electrical input. Only projects with a disclosed start year are included.
Source: IEA Hydrogen Production Projects Database (September 2025).

Announced projects account for 440 GW of electrolysis by 2030, but more than two-thirds of that capacity has low potential or is uncertain to be operational by 2030.

There are significant regional differences in the likelihood of projects being operational by 2030. China alone accounts for one-third of the capacity that is almost certain or has strong potential to be available by 2030, and 85% of the announced capacity in the country falls under these two categories (Figure 3.13). Canada, Europe and the United States account for another 50% of the capacity that is almost certain or has strong potential to be available by 2030, with 18-26% of the capacity announced in these regions falling under these categories. On the other hand, Latin America and Africa are home to more than one-third of the capacity that has low potential or is uncertain to be operational by 2030, and around 95% of the capacity announced in these regions falls under these two categories. This points to a maturing pipeline in China and advanced economies, where the majority of the advanced projects with robust business cases are located, and the most developed policy frameworks are in place. In EMDEs, a large share of projects are export-oriented, relying on offtake at scale from other regions and the development of a global hydrogen market, which is lagging. These projects are expected to go through the same process of maturation that has been seen in advanced economies, in which the least robust and more speculative projects have been (or are being) abandoned, with industry focusing instead on mature projects with clear business cases.

Figure 3.13 Likelihood that announced electrolysis projects will be operational by 2030 by region



IEA. CC BY 4.0.

Source: IEA Hydrogen Production Projects Database (September 2025).

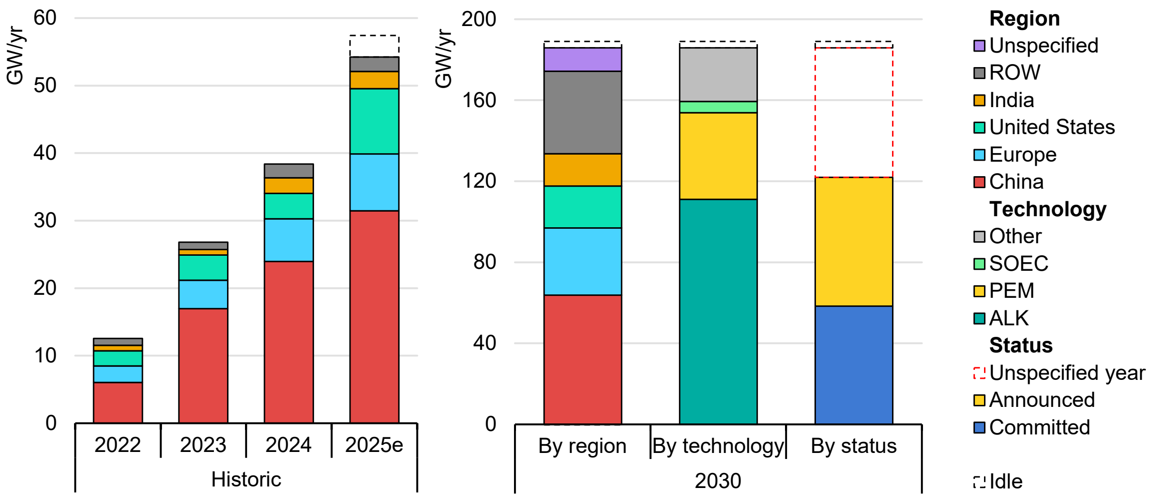
Large electrolysis capacities have been announced in EMDEs, but the current market and policy environment mean that it appears difficult for them to be operational by 2030.

Electrolyser manufacturing

Electrolyser manufacturing capacity continued to grow in 2024, but growth is slowing everywhere except China

Electrolyser manufacturing capacity grew further in 2024 to reach close to 38 GW/yr, based on the nominal facility size from company announcements (Figure 3.14). This is a 40% increase compared with the manufacturing capacity available at the end of 2023, with China responsible for the majority of this growth. However, we estimate that the output of these facilities reached only around 4 GW in 2024, meaning that there is a large excess capacity today and only around 10% of the existing capacity has been active. Based on company plans, manufacturing capacity could reach close to 60 GW/yr in 2025. However, this expansion is highly uncertain given recent announcements of delays and cancellations (Table 3.1) resulting from existing excess capacity and slow market development for electrolysers globally (with the exception of China). Moreover, more than 3 GW/yr of manufacturing capacity is today idle due to a pause in operations at several manufacturing sites. In addition, some manufacturers have filed for bankruptcy (see next section), although some of the assets from these companies have already been acquired by other original equipment manufacturers (OEMs) and could start operating again soon.

Figure 3.14 Electrolyser manufacturing capacity by region, 2022-2025e, and announced capacity additions by region, technology and status, 2030



Notes: ALK = alkaline electrolyser; PEM = proton exchange membrane; SOEC = solid oxide electrolyser; ROW = Rest of World; 2025e = estimate for 2025 based on projects already under construction that target commencing operations in 2025. "Committed" refers to capacity that is operational, under construction or with FID.

Source: IEA analysis based on announcements by manufacturers and personal communications.

Manufacturing capacity is expected to increase again in 2025, mainly driven by developments in China as manufacturers elsewhere are struggling with low demand.

Looking forward, based on announced expansions by OEMs, electrolysis manufacturing capacity could reach almost 190 GW by 2030. However, only China has significantly increased this potential capacity for 2030 compared with the estimate presented in GHR-24. The capacity that is committed (i.e. starting construction or having reached FID) has grown by around 20% since the release of GHR-24, but nearly one-third of the announced capacity has no target year for starting operations, meaning that its availability by 2030 is highly uncertain.

In terms of technology breakdown, alkaline electrolysers are expected to remain the leader, accounting for almost 60% of the potential capacity by 2030 and three-quarters of the growth in potential capacity by 2030 compared with last year's estimate. Alkaline is the technology with the largest manufacturing capacity at present, and it is also the preferred technology for Chinese manufacturers (more than 90% of existing manufacturing capacity in the country is for alkaline electrolysers). Although some OEMs in China are aiming to expand to other electrolyser designs, alkaline is still expected to dominate the technology mix in 2030, with nearly 90% of potential capacity in China.

Electrolyser manufacturers are facing headwinds from slow market development

With the exception of China, the ramp-up of electrolysis deployment has fallen far short of electrolyser manufacturers' expectations. Electrolyser sales contracts are being significantly delayed or cancelled as project developers struggle to secure financing and reach FIDs.

As a consequence, several electrolyser manufacturers outside of China are experiencing sharp reductions in revenue and increased losses, and for some this has spelled the end of operations or acquisition by other OEMs (Table 3.1). However, such difficulties are not widespread and some large players are weathering the storm well, particularly alkaline electrolyser manufacturers with large market shares in the traditional chlor-alkali business, which is helping to compensate negative results from the hydrogen production business. In addition, some manufacturers are still raising capital to support strategic development or are developing and testing new business models.

To preserve cash and adjust to lower demand, manufacturers have paused factory operations, re-assessed their manufacturing businesses and announced significant job cuts. These measures are being seen across the sector, as companies try to survive a period of low order intake, with the long-term outlook for renewable hydrogen still positive, driven by decarbonisation and energy security goals. Nevertheless, it seems inevitable that the sector will go through a wave of consolidation, with partnerships, mergers or exits likely to occur. In this context, the most competitive and well-capitalised firms are better placed to survive the current downturn.

Table 3.1 Selected examples of the effects of slow market development for electrolyser manufacturers

Manufacturer	Country	Impact
McPhy	France	EUR 74.1 million loss in 2024, share price down almost 80%. Moving into judicial liquidation in Q2 2025. Some assets acquired by John Cockerill.
Nel	Norway	1 GW/yr factory in Herøya idled due to weak demand, 20% staff cut, 48% revenue drop Q2 2025 and order backlog down 40% y-o-y.
Elogen	France	Factory project cancelled after failing to secure orders, which could lead to 110 layoffs.

Manufacturer	Country	Impact
Quest One	Germany	120 jobs cut at Augsburg headquarters and Hamburg factory due to slow market ramp-up.
HydrogenPro	Norway	Loss of NOK 200 million (Norwegian kroner) (~USD 19 million) in 2024 due to cancellations of large projects from prospective clients.
Green Hydrogen Systems	Denmark	Filed for bankruptcy in June 2025. Intellectual property and test site acquired by thyssenkrupp nucera.
Fortescue	Australia	Paused manufacturing on its 2 GW factory in Gladstone to redirect resources to other technology developments to support green iron plans.

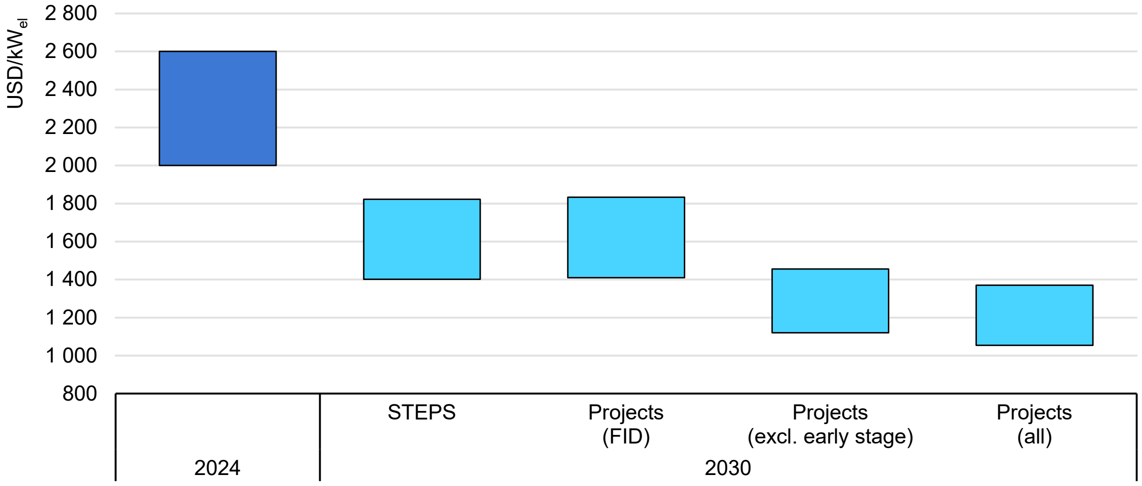
Slower-than-expected electrolyser deployment is limiting equipment reduction cost potential by 2030

The cost of installing an electrolyser represents a significant part of the levelised cost of hydrogen (LCOH). With the momentum seen in the past few years, it had been expected that this cost could be reduced quickly in the short term, thanks to factors including innovation, learning-by-doing, economies of scale and improved manufacturing techniques. However, slower-than-expected deployment (outside of China) has prevented the achievement of significant economies of scale that can meaningfully reduce cost. In addition, the high inflation of 2022-2023 has led to an opposing trend, with the cost of electrolysers increasing everywhere in the world except in China in the last few years, in line with a general trend in chemical plant equipment.

Based on a survey carried out by the IEA among companies across the supply chain for electrolyser projects, in 2024, the capital cost of installing an electrolyser made outside of China ranged between USD 2 000/kW and USD 2 600/kW (Figure 3.15).[34] In the case of an electrolyser made in China and installed in China, these costs are significantly lower, reaching USD 600/kW-1 200/kW.[35] However, more than half of the total cost of an installed electrolyser corresponds to EPC and contingency costs, which entirely depend on the project location. Higher EPC costs, along with the need to adapt the technology to local standards,[36] mean that the capital cost of installing an electrolyser made in China elsewhere in the world ranges between USD 1 500/kW and USD 2 450/kW, significantly reducing the cost savings (see next section).

[34] The reported range of capital cost of electrolysers considers only alkaline technology and includes the equipment, gas treatment, plant balancing, EPC cost, and contingencies.
[35] Costs are dropping falling fast and some electrolyser tenders in China have reached values below USD 200/kW, but it is unclear whether they include all the cost components considered in the USD 600-1 200/kW range.
[36] Electrolyser price survey 2024: rising costs, glitchy tech, BloombergNEF, 1 March 2024.

Figure 3.15 Costs of electrolysers manufactured outside of China in 2024 and potential cost reduction based on a level of deployment compatible with announced projects and the Stated Policies Scenario, 2030



Notes: STEPS = Stated Policies Scenario; FID = final investment decision. "Projects (FID)" refers to the capacity deployed according to announced projects that have at least reached FID, which is 29 GW by 2030. "Projects (excl. early stage)" refers to the capacity deployed according to all announced projects excluding those that are at early stages of development, which is 240 GW by 2030. "Projects (all)" refers to the capacity deployed according to all announced projects, which is 440 GW by 2030. In the case of the STEPS, this capacity is 40 GW by 2030. The learning rate for the electrolyser stack is assumed at 13%, while for the other components of the balance of plant it is 2-5%. For the engineering, procurement and construction (EPC) costs, a learning rate of 8% has been assumed.

Sources: IEA analysis based on data collected through a survey to original equipment manufacturers, EPC companies and project developers, data from McKinsey & Company and the Hydrogen Council; BloombergNEF, Argus Media Group, All rights reserved, the IEA Hydrogen Production Projects Database (September 2025) and IEA (2024), Advancing Clean Technology Manufacturing.

The cost of installing electrolysers could fall by 50% by 2030, but the current slower-than-expected deployment is likely to significantly limit these cost reductions.

Breaking down the CAPEX of installing an electrolyser helps to assess where the cost reduction potential is and how big it could be. Around 15-20% of the CAPEX corresponds to stack components, which are the components that present most potential for cost reduction through innovation. In contrast, 25-30% corresponds to balance of plant components (such as power electronics, piping, compressors and gas treatment), which are already commercially available equipment with limited potential to reduce costs. As noted above, more than half of the capital cost corresponds to EPC and contingency, for which cost reduction potential is uncertain. EPC companies and project developers are gaining experience with electrolyser projects, but they are still seen as first-of-a-kind, with significant development risks associated. As more experience is gained and more technology providers can guarantee the performance of their products, these costs will fall. In addition, several OEMs and project developers are working on novel technical alternatives with the objective of reducing the total CAPEX by more than 50% in projects that have already reached FID (Box 3.3).

In the STEPS, the capital cost of installing an electrolyser manufactured outside of China declines by around 30% by 2030, in line with the cost reduction that could be achieved with the level of deployment expected from projects that have already taken FID. This can slightly close the cost gap with projects developed in China using Chinese-made electrolysers, which will remain significantly cheaper in the short term. If the full project pipeline is realised, the capital cost could fall by 50% by 2030, although achieving this level of deployment in just 5 years in the current market and policy environment is unlikely.

Box 3.3 Modular and standardised designs to reduce the cost of electrolysis projects

As outlined above, more than 80% of an electrolysis project's CAPEX is attributed to the balance of plant (BoP) and EPC, where opportunities for cost reduction through innovation and learning-by-doing are limited. In response, OEMs and EPC companies are exploring ways to lower the costs of these components. Scaling-up and standardisation are key strategies, enabling reduced equipment redundancy, bulk purchasing and automated production, thereby lowering per-unit overheads.

To this end, several OEMs, including thyssenkrupp nucera and ITM Power, are commercialising skid-mounted or containerised solutions. These modular designs optimise plant footprint and facilitate efficient integration of core electrolysis components with BoP through "plug-and-play" solutions. Standardised modules can also be pre-fabricated and pre-tested, reducing delivery risks and project lead times.

In addition, OEMs are partnering with EPC companies to develop integrated, standardised plant designs that can be replicated across multiple projects, reducing engineering costs by avoiding ad-hoc designs for each project. In March 2025, Nel Hydrogen and Samsung E&A signed a collaboration agreement – including a 9.1% equity investment by Samsung – to develop integrated hydrogen production solutions. In November 2023, Technip Energies and John Cockerill established Rely, a joint venture which is now commercialising the Clear100+, a standardised 100 MW low-emissions hydrogen facility using John Cockerill's pressurised alkaline electrolysers. In May 2025, InterContinental Energy presented its P2H2Node system, a standardised project architecture aiming to reduce engineering time and streamline project development, targeting modest cost reductions of around 10%.

Electric Hydrogen (EH2) has also developed the HYPRPlant modular plant (configurable from 75 MW to 120 MW), based on proprietary PEM electrolyser technology. EH2 combines the modularisation strategy, using skid mounting equipment along with an approach to shift more engineering and construction activities to manufacturing sites, rather than on-site construction, reducing both costs and delivery risks. EH2 is deploying this design for the first time in the Infinium Roadrunner project, which reached FID in May 2025, targeting a total project CAPEX of less than USD 1 000/kW. If this value is achieved, it could make the cost of electrolysers manufactured and installed outside of China comparable to costs for alkaline electrolysers manufactured and installed in China.

While these solutions mark significant progress in reducing technology costs, they also present challenges. For brownfield projects, existing site layouts may constrain equipment placement or access to essential services, or require additional engineering, potentially reducing the cost savings associated with standardisation. Furthermore, the fixed size of standard modules may limit their suitability for projects that require intermediate capacities, especially during the early ramp-up phase of the renewable hydrogen market.

The use of Chinese electrolysers outside China can reduce hydrogen production costs, but the impact is rather limited

Electrolysers manufactured in China are starting to attract interest from project developers outside the country. This interest has grown in the last couple of years, mostly due to the lower CAPEX of Chinese alkaline technology, but also thanks to a growing offer, both from traditional electrolyser manufacturers and new market-entrants (including solar PV and wind manufacturers that have moved into electrolysis manufacturing, such as LONGi, Sungrow, Trina and Envision), and increasing confidence in the technology provided. Some Chinese OEMs have started addressing concerns that project developers have raised in terms of the efficiency and performance of their products, and are already manufacturing equipment that can meet standards elsewhere. Commercial projects of 5-10 MW in scale using electrolysers manufactured in China are already operating in different countries (for example in Norway and Namibia), and projects larger than 100 MW are under construction (in Germany, Oman and the United States).

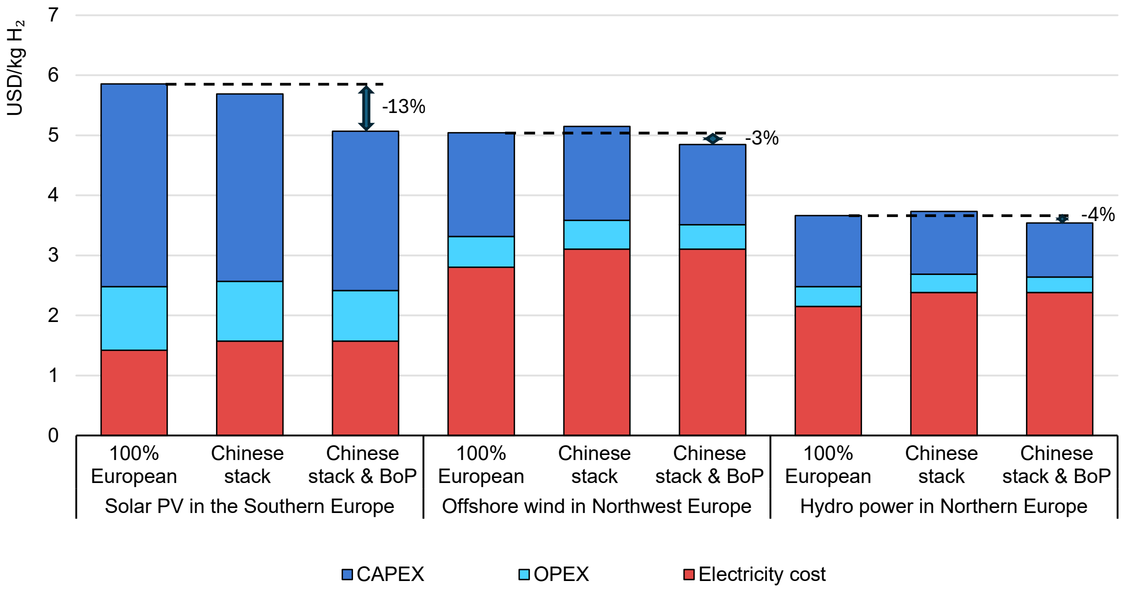
In addition, several Chinese OEMs are exploring the option of expanding operations overseas to reach emerging markets and to respond to trade restrictions, such as local content requirements in policies, or trade sanctions. In September 2024, Hygreen Energy announced plans to build a manufacturing site in Spain that could reach up to 5 GW/yr of manufacturing capacity depending on demand developments in Europe. Chinese companies are also starting to establish co-operations with companies elsewhere to sell their technology outside of China. In 2023, PERIC, China's largest electrolyser manufacturer, signed an agreement with Metacon, a Swedish technology provider, to license PERIC electrolyser technology for manufacture in Sweden. In May 2024, Sungrow

Hydrogen signed an agreement with BrightHy Solutions (a subsidiary of the Portuguese company Fusion Fuel Green) to sell hydrogen equipment in Spain and Portugal.

These rapid developments have raised concerns among governments and companies outside of China that there could be a repeat of the experience seen with other clean energy technologies, such as solar PV, wind or batteries, for which China has become the global leader having overtaken earlier leads from other countries, particularly in Europe. In addition to challenges to competitiveness, such a situation could raise concerns about supply chain concentration. However, although the CAPEX for Chinese electrolysers is significantly lower than for electrolysers manufactured elsewhere, using equipment manufactured in China instead of equipment manufactured in other countries has only a small impact on the final cost of producing hydrogen for projects developed outside of China. The total cost of using Chinese-manufactured electrolysers in projects outside of China is significantly larger than installing that equipment in China due to the large share of EPC and contingency costs. As a result, the total CAPEX of installing a Chinese electrolyser in countries other than China is around 5-25% lower than using electrolysers manufactured outside of China, once the cost of transporting components from China is added. In addition, the cost of electricity accounts for a significant share of the cost of producing hydrogen, and given that Chinese electrolysers generally still present issues with underperformance and efficiency, the cost of electricity has a higher impact, partially cancelling out the cost savings achieved through the lower CAPEX associated with the electrolysers.

For example, for projects running on renewable electricity in Europe, the potential cost reduction that can be achieved today by using Chinese equipment ranges between 3% and 13% (Figure 3.16), depending on the electricity source and the share of equipment that is replaced with Chinese components (i.e. the stack alone or components of the BoP as well). Moreover, in some project configurations where the cost of electricity accounts for a very large share of the final cost of producing renewable hydrogen, the lower efficiency and performance of Chinese equipment can wipe out the potential savings from the lower CAPEX, and even lead to slightly higher LCOH production than using European equipment alone.

Figure 3.16 Levelised cost of hydrogen production for different project configurations using electrolysers manufactured in Europe and imported from China, 2024



Notes: BoP = balance of plant. "100% European" refers to a project configuration which only uses equipment manufactured in Europe, with an electrolyser CAPEX of USD 2 300/kW. "Chinese stack" refers to a project configuration using electrolyser stacks imported from China with all the rest of the equipment procured from original equipment manufacturers (OEMs) from Europe, with an electrolyser CAPEX of USD 2 150/kW. "Chinese stack & BoP" refers to a project configuration using electrolyser stacks and the rest of BoP components imported from China, with an electrolyser CAPEX of USD 1 800/kW. Electrolyser efficiency is 62% for "100% European" and 56% for the other two cases. The total import cost of Chinese components includes the manufacturing cost in China, shipping costs and an import tariff of 3.7% tariff on electrolyser stacks and 2% on BoP components. Engineering, procurement and construction (EPC) and contingency costs are considered to be at European prices for all project configurations.

Sources: IEA analysis based on data collected through a survey to original equipment manufacturers, EPC companies and project developers, data from McKinsey & Company and the Hydrogen Council; BloombergNEF, Argus Media Group, All rights reserved.

Despite the significantly lower CAPEX of Chinese electrolysers, their use in projects outside of China leads to only small reductions in the cost of producing hydrogen.

This difference in cost does, of course, have policy implications. With regards to support in the form of CAPEX grants, using Chinese components would enable a larger-scale deployment within the same budget. For example, a programme with a budget of USD 1 billion would be able to support the deployment of 1.1 GW of electrolysis capacity, if components manufactured outside of China are used, compared to up 1.4 GW if the use of Chinese components is permitted, although the potential production from that capacity using Chinese electrolysers could be slightly lower due to their lower performance.[37] Similarly, a 200 MW project running on solar PV in southern Europe that receives support from the European Hydrogen Bank would require a fixed premium of EUR 0.6-1.8 more per kilogramme of hydrogen if using components manufactured outside of China rather than imported Chinese equipment in order to recover the additional

[37] Assuming the use of alkaline technology and that the grant cannot cover more than 40% of the project CAPEX cost.

investment in the 10 years of support provided by the scheme.[38] When designing support schemes for electrolysis projects, governments will need to carefully balance these potential cost savings with the need to develop a domestic manufacturing industry that can help to diversify the supply chain, protect jobs and boost economic growth.

Fossil fuels with CCUS

Coal, oil and natural gas-based processes made up more than 80% of total hydrogen produced in 2024. Less than 1% of these processes were equipped with CCUS technology, based in about 16 hydrogen facilities[39] around the world, largely in North America. Most of these CCUS facilities have been retrofitted to hydrogen production units in refining and fertiliser production, and some date back to the 1980s. These have a cumulative capture capacity of around 12 Mtpa CO_2. However, only around 1 Mtpa of the captured CO_2 is injected in dedicated storage (at the Quest facility in Canada), and the remainder is injected for enhanced oil recovery (EOR) or used in other applications. While most of the CO_2 injected for EOR can be retained in the reservoir over the life of the project, additional monitoring and verification is required to confirm that the CO_2 has been permanently stored. All facilities in operation at the end of 2024 have been retrofitted with partial capture, meaning that only process emissions – which have a high concentration of CO_2 – are captured. This resulted in only around 0.6 Mtpa H_2 production at the end of 2024 qualifying as low-emissions out of the 0.9-1.2 Mtpa produced (Figure 3.17),[40] with 0.35 Mtpa from natural gas reforming (3.5 Mtpa CO_2 captured), and 0.3 Mtpa from coal and oil gasification (7.5 Mtpa CO_2 captured).

Hydrogen production represents about a third of announced capture capacity by 2030, making it one of the leading applications in CCUS announcements. These applications are not limited to dedicated hydrogen production facilities, but also include hydrogen produced for internal use in ammonia, fertiliser, steel and iron industries.

The United States accounts for almost half of announced hydrogen production projects with CCUS by 2030, with two projects having taken FID in the past year. In July 2024, CF Industries took FID for the retrofit of the Yazoo City Complex ammonia plant in Mississippi, targeting the partial capture of the plant's emissions,

[38] Assuming 1 400 full load hours of annual operation, 56% system efficiency and full replacement of stack and BoP with Chinese components.
[39] Only projects with a capture capacity above 100 000 t CO_2 per year are considered here.
[40] Low-emissions hydrogen production is estimated from the plant CO_2 capture capacity, and therefore only includes hydrogen production for which CO_2 is captured and stored. The range of total hydrogen production is estimated assuming a 40-60% overall unit capture rate for gas-based production and 90-95% for coal and oil-based production, including projects capturing CO_2 for utilisation.

amounting to around 0.5 Mtpa CO_2, with ExxonMobil providing the CO_2 transport and storage services. This was followed in April 2025 by a USD 4 billion FID through a joint venture between CF Industries, JERA and Mitsui to develop a new 1.4 Mtpa ammonia facility in Louisiana. The project aims to capture 2 Mtpa CO_2, approximately 95% of the plant's emissions, for storage at the Pelican Sequestration Hub. Additionally, CF Industries' partial capture retrofit at its Donaldsonville facility commenced operations in July 2025, capturing 2 Mtpa CO_2 for interim use for EOR with a planned transition to dedicated storage once the necessary infrastructure is ready. Linde's Beaumont plant is also expected to start producing hydrogen for an adjacent ammonia facility (now under Woodside Energy ownership); however, CO_2 capture at the site, targeting 1.7 Mtpa CO_2, is scheduled to begin in 2026. ExxonMobil will provide CO_2 transportation and storage services for both the Donaldsonville and Beaumont facilities using Class VI wells. A major incentive for these investments is the availability of tax credits under Section 45Q and Section 45V (credits cannot be combined). Section 45Q provides up to USD 85 (around USD 0.8/kg H_2)[41] per tonne of CO_2 stored, and USD 60 (around USD 0.55/kg H_2) per tonne of CO_2 used, over the first 12 years of operation. Meanwhile, Section 45V offers up to USD 3.2/kg H_2 produced in the first decade of operation depending on the well-to-gate carbon intensity of the production process (see Chapter 6 Policies). However, it would be difficult for fossil-powered hydrogen production facilities to qualify for the highest 45V tier of support reserved for hydrogen with emissions below 0.45 kg CO_2-eq/kg H_2, given that upstream and midstream emissions alone average around 1.8 kg CO_2-eq/kg H_2, nearly four times the threshold. Although the US Treasury released final guidelines for the 45V programme in January 2025, enabling project developers to submit applications, only a narrow window remains to access the credit, as eligibility is now limited to projects that begin construction before the end of 2027. In parallel, the future of the four hubs that include projects using natural gas with CCUS under the USD 7 billion Regional Clean Hydrogen Hubs Program remains unclear, with discussions ongoing about potential reductions in funding which might hamper progress.

Canada is the second-largest producer of hydrogen from fossil fuels with CCUS, accounting for more than one-fourth of global output in 2024. By 2030, Canada is expected to account for approximately one-sixth of the announced global production. Federal incentives such as the CCUS Investment Tax Credits and the Clean Hydrogen Investment Tax Credits are supporting investments, alongside state-level programmes like the Alberta Petrochemicals Incentive Program and the Alberta Carbon Capture Incentive Program. In June 2024, Shell Canada reached FID for both the Polaris project and associated transport and storage infrastructure, Atlas Carbon Storage Hub, a joint venture with ATCO EnPower.

[41] Assuming gas-based production, 0.9105 kg CO_2 emitted per normal cubic metre (Nm^3) H_2 and 90% capture rate.

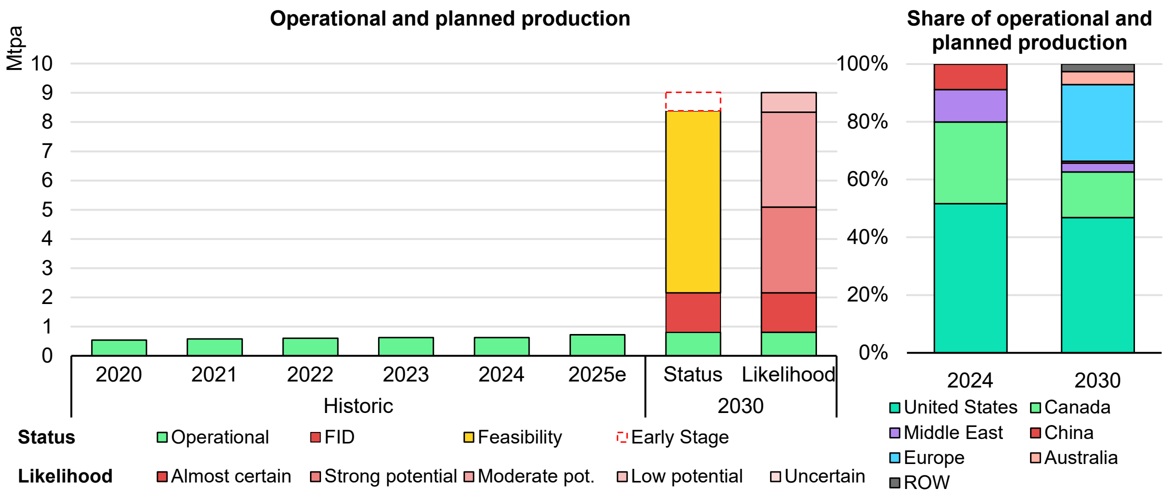
Polaris is designed to capture and store approximately 0.6 Mtpa of CO_2 from hydrogen production units at Shell's Scotford refinery, with operations expected to begin in 2028. The project builds on the success of the nearby Quest facility which has sequestered over 9 Mt CO_2 since start-up in 2015. However, project delays continue: despite initial plans for a 2024 start, the commissioning of Air Products' Net-Zero Hydrogen Complex in Alberta has been pushed to late 2027 or early 2028, with capital costs almost tripling from USD 1.2 to USD 3.3 billion due to project management difficulties.

Hydrogen production from fossil fuels with CCUS is experiencing renewed momentum in Europe, driven primarily by government funded decarbonisation programmes and major investments in CO_2 transport and storage infrastructure. By 2030, the region could account for around one-quarter of global low-emissions hydrogen production from fossil fuels with CCUS. With USD 28 billion made available by the UK Government to support CCUS deployment for two industrial clusters, the United Kingdom is leading hydrogen-CCUS developments in Europe, making up roughly 40% of the region's planned production for 2030. In April 2025, an FID was reached for Hynet's Liverpool Bay CCS project, which aims to transport and store about 4.5 Mtpa CO_2 starting from 2028. The project will facilitate CO_2 capture from the Hynet industrial cluster, including EET Hydrogen's Hydrogen Production Project with the capacity to produce more than 0.3 Mtpa H_2. Similarly, the Northern Endurance Partnership, which will facilitate sequestration of captured carbon from H2Teesside, reached FID in December 2024. While investments are yet to be finalised for the associated hydrogen plants, the progress on the CCS infrastructure indicates a significant step forward. In the Netherlands, two retrofit capture projects on existing hydrogen plants are currently under construction, along with associated transport and storage infrastructure (Porthos), steadily aiming for a 2026 start. Recent FIDs in CO_2 transport and storage infrastructure in Denmark and Norway could further support capture announcements across industries, including hydrogen production.

In the Middle East, fossil-based hydrogen production with CCUS is expected to increase almost fourfold by 2030 if all announced projects come to fruition. This expansion is fuelled by available low-cost natural gas, accessible CO_2 storage capacity and the region's ambition to produce low-emissions fuels. In December 2024, project partners for Saudi Arabia's Jubail CCS hub, one of the largest hubs in the pipeline, reached an equity agreement with FID expected by the end of 2025. In anticipation, Linde is exploring the development of a hydrogen plant to leverage the hub's infrastructure. In Oman, while the national hydrogen strategy prioritises electrolytic hydrogen, Shell is undertaking a feasibility study for the Blue Horizons project, a large-scale fossil-based hydrogen and ammonia production facility with CCUS, which is expected to be the first of its kind in Oman.

If all announced projects are realised in full and on time, low-emissions hydrogen production with CCUS could increase from 0.6 Mtpa in 2024 to around 9 Mtpa by 2030. Projects that have at least taken FID represent about 15% of the potential additional production, whereas early-stage projects account for less than 10%. Natural gas with CCUS remains the dominant pathway, making up more than 90% of the announced hydrogen production by 2030, primarily through steam methane reforming (SMR) or autothermal reforming (ATR) technologies. In contrast, coal and oil-based hydrogen plants mainly using gasification could make up less than a tenth of operational facilities by 2030.

Figure 3.17 Production of low-emissions hydrogen from fossil fuels with carbon capture, utilisation and storage, historical and from announced projects, 2020-2030



Notes: CCUS = carbon capture, utilisation and storage; FID = final investment decision; Moderate pot. = Moderate potential; 2025e= estimate for 2025, based on projects planned to start operations in 2025 and that have at least reached FID. FID refers to projects have at least taken FID and those that are under construction. Only includes projects with an announced operating date before 2030, assuming they will start on time.

Source: IEA Hydrogen Production Projects Database (September 2025).

More than half of the potential hydrogen production from planned projects using fossil fuels with CCUS is almost certain or has strong potential to be operational by 2030.

Our assessment suggests that over half (around 5 Mt) of the potential production from planned projects is almost certain or has strong potential to be operational by 2030. Of the remaining half, roughly one-third has moderate potential to be operational by 2030 and less than one-tenth has low potential. Planned projects are often impeded by several bottlenecks, resulting in long project lead times or in some cases, cancellations. Given that most operating plants are capital-intensive first-of-a kind facilities, securing project financing remains a major hurdle and a leading cause of delays, especially in countries with limited government-backed financial incentives.

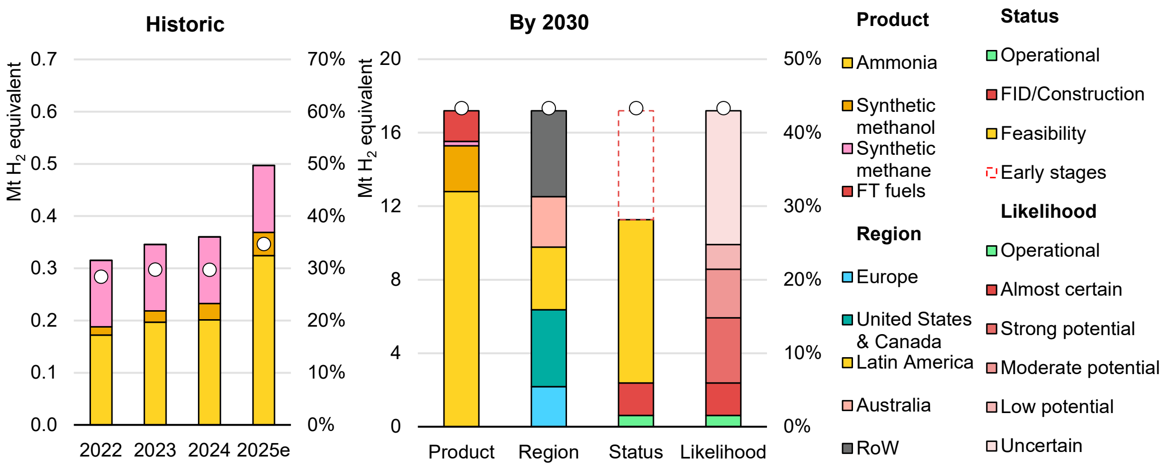
Connecting capture projects to existing transport and storage infrastructure could lower associated costs and improve the business case, but securing commitments from all stakeholders requires effective co-ordination, which has proven to be challenging. A notable example is the Alberta Carbon Trunk Line project, which captures, transports and stores CO_2 from two facilities including a fertiliser plant, and took a decade to reach completion due to such complexities. Moreover, challenges in securing permits and other relevant regulatory approvals often extend project timelines. These delays can, in turn, lead to inflated project costs which undermine project viability and delay FIDs. Another major barrier stalling project development is the challenge of securing offtake agreements, which are essential for derisking investments. For instance, construction of Air Products' 0.7 Mtpa H_2 facility in Louisiana, which reached FID in 2023, has been paused until offtake agreements are secured. Given these constraints, the successful and timely deployment of planned projects is dependent on the full implementation of existing and planned policy and financial incentives. Projects that have moderate or low potential to be operational by 2030, in particular, will require further support to move forward.

Production of hydrogen-based fuels and feedstock

The production of low-emissions hydrogen for the subsequent production of hydrogen-based fuels and feedstocks grew 4% in 2024, with nearly all of this growth concentrated in the production of methanol and ammonia (Figure 3.18). Based on announced projects that have taken FID and are under construction with the aim of starting operation this year, production is expected to increase nearly 40% to reach nearly 0.5 Mt H_2, primarily boosted by large CCUS projects in North America for the production of ammonia. More than half of the low-emissions hydrogen produced for the manufacturing of hydrogen-based fuels and feedstocks in 2024 was used for the production of ammonia, followed by synthetic methane, for which almost all the production was concentrated in the Great Plains Synfuels plant in the United States. The plant owners announced an agreement in 2021 to sell the plant and transform it into a hub for the production of hydrogen from fossil fuels with CCUS from 2025, but this has not yet materialised.

Based on announced projects, the use of low-emissions hydrogen in the production of hydrogen-based fuels and feedstocks could reach 17 Mt H_2 by 2030, accounting for 45% of all potential low-emissions hydrogen production. This is nearly 3 Mt H_2 lower than the potential production estimated in GHR-24, mostly due to cancellations and delays in very large ammonia export-driven projects. On the other hand, synthetic methanol projects have nearly doubled compared to last year, whereas projects for Fischer–Tropsch (FT) fuel production have remained at similar levels. The implementation of policies to stimulate demands for these fuels, particularly the sustainable aviation fuel (SAF) mandates in the European Union and the United Kingdom, suggest that we may see an increase in these projects in the near term, although market participants have raised concerns about supply availability to meet those mandates by 2030.[42] In the case of synthetic methane, despite its large share in today's low-emissions hydrogen use for the production of hydrogen-based fuels and feedstocks, it accounts for a very minor share of announced projects by 2030.

Figure 3.18 Projects for hydrogen-based fuels and feedstocks by product, 2022-2025, and announced projects by product, region, status and likelihood, 2030



Notes: FID = final investment decision; FT = Fischer–Tropsch; ROW = rest of world; 2025e= estimate for 2025, based on projects planned to start operations in 2025 and that have at least reached FID. The percentage share represents the share of hydrogen inputs for the production of hydrogen-based fuels and feedstocks in the total low-emissions hydrogen production from all announced projects for low-emissions hydrogen and hydrogen-based fuels production.
Source: IEA Hydrogen Production Projects Database (September 2025).

Hydrogen-based fuels and feedstocks account for 45% of the pipeline of low-emissions hydrogen production, but half has low potential or is uncertain to be operative by 2030.

Regionally, there has been a significant decrease in export-oriented projects in Australia and to a lower extent in Africa and Latin America, some of which have been cancelled, while others have delayed their targeted operational date until after 2030 given the slow development of a global market for these products. On the other hand, there has been a significant increase in planned projects in Latin America (nearly 25% higher than in GHR-24, reaching 3.4 Mt H_2). Brazil has been the main driver, thanks to the acceleration enabled by the hydrogen hubs programme launched in 2024. However, practically all the projects in the region are still at early stages of development or are undergoing feasibility studies, and their realisation by 2030 remains in question.

[42] EU alternative aviation fuel mandates highlight synthetic fuel supply concerns, Platts Hydrogen Daily, 9 April 2025.

Across announced projects, the production that has reached FID has grown almost 40% compared with last year. This still accounts for only 11% of the total announced production, although this is larger than the share for all hydrogen projects. This suggests that projects targeting the production of hydrogen-based feedstocks and fuels are better placed to find offtake and reach financial closure in the short term. The majority of this production is concentrated in the United States, China and the Middle East (highly concentrated in the NEOM Green Hydrogen project in Saudi Arabia). The potential production by 2030 from projects at an early stage has decreased significantly compared to last year (-40%). In part, this is because some projects have progressed to feasibility studies, but the majority of this drop is a consequence of delays to the plans for after 2030, due to slow market development (which makes it difficult to secure long-term offtakers) and the abandonment of initiatives with weak business cases announced during the hydrogen boom period of the past few years.

In our assessment of the likelihood of projects being operational by 2030, nearly 35% of the potential capacity is operative, almost certain or has strong potential to be operative by 2030. Projects for the production of hydrogen-based fuels and feedstocks represent more than half of the total low-emissions hydrogen production in these categories, highlighting the potential that these fuels and derivatives present to stimulate demand and mobilise investment in production. However, half of the production coming from these projects has low potential or is uncertain to be operative by 2030, with the bulk of this production coming from early-stage export-oriented projects based in EMDEs, where the hydrogen boom period is still not over.

Chapter 4. Hydrogen trade and infrastructure

Highlights

- Trade is a major driver of project announcements. Nearly 45% of low-emissions hydrogen from announced production projects is intended for export, exceeding 16 Mtpa H_2-eq by 2030 if all materialise. Yet export-oriented projects are less likely to reach the investment stage, with only 5% having done so. These projects tend to be large scale, lacking off-takers. More than half are in emerging and developing economies, where affordable capital and export infrastructure may be limited.
- Some governments are supporting the large-scale offtake of low-emissions hydrogen by providing funds for long-term premiums through competitive auctions. However, not all allocated funding has been awarded in initial rounds due to a range of difficulties, including regulatory uncertainty, limited funding volumes and currency risk, prompting modifications to the design of subsequent rounds.
- Around 37 000 km of hydrogen pipelines have been announced to 2035, but less than 6% have reached final investment decision (FID). Most projects are in Europe and China, where the world's longest, largest-diameter hydrogen pipelines are currently being built. In Germany, work began on repurposing a 400 km section of a natural gas pipeline in 2025, in a world-first repurposing project of this scale.
- If all announced underground hydrogen storage projects are realised by 2035, around 11 TWh of capacity (325 kt H_2) will be available. However, only 5% has reached FID or is under construction, equivalent to 2.5% of the annual output from committed low-emissions hydrogen projects. Progress remains concentrated in Germany, where one commercial-scale salt cavern project has reached FID.
- By 2030, over 130 high-traffic ports could have access to at least 100 ktpa of low-emissions hydrogen within a distance of 500 km, based on announced production projects, though availability varies widely by location and cargo segment.
- Nearly 80 ports score more than 5 (out of 10) in the IEA's Chemical-handling Infrastructure Score, which reflects physical infrastructure and operational expertise that can enable the adoption of low-emissions fuels.
- Of these, 55 ports have significant nearby hydrogen supply and high infrastructure readiness, meaning they could be early candidates for low-emissions hydrogen-based fuel bunkering. However, ability to support methanol or ammonia bunkering will also depend on access to sustainable carbon sources in the case of methanol, and sufficient space for handling ammonia safely.

Overview and outlook for hydrogen trade

The potential for trade is a major driver behind many announced low-emissions hydrogen projects

Today, most hydrogen is produced and consumed on-site. Limited volumes of pure hydrogen are transported by truck or pipeline, mainly for industrial use within regional networks, including some cross-border infrastructure in Europe. Although hydrogen derivatives such as ammonia and methanol are traded internationally, volumes remain modest, as they are currently used as chemical feedstocks rather than energy carriers. Around 10% of global ammonia production is traded as liquefied gas in tankers, while, among its main derivatives, urea, easier to store and handle, is traded in bulk more widely, at about 30% of its production. Around a third of methanol is traded internationally in liquid tankers.

Traditionally, the trade of hydrogen-derived products has been driven by the availability of natural gas, with major exporters typically being countries that produce large amounts of natural gas. Looking forward, countries with abundant renewable resources, or those with the capacity to use natural gas alongside carbon capture, utilisation and storage (CCUS), could become key suppliers of low-emissions hydrogen and its derivatives, such as ammonia, methanol and synthetic kerosene. In addition to these energy carriers and feedstocks, countries may export higher-value hydrogen-based products, such as other nitrogen-based fertilisers and hot briquetted iron. While some producers and consumers may be able to use existing infrastructure, many will require new or adapted supply chains to support future trade on a large scale.

Publicly backed competitive offtake is gaining momentum to enable initial low-emissions hydrogen trade

Publicly backed offtake contracts, i.e. firm purchase agreements, have long been used in the energy sector to reduce investment uncertainty, with governments awarding long-term purchase commitments through competitive auctions. Similar competitive procurement mechanisms are now being applied to low-emissions hydrogen. Moreover, given that international hydrogen supply chains will require large-scale, long-term offtake commitments in order to justify infrastructure investment and reduce early-stage project risk, several countries aiming to import hydrogen are now adopting schemes that are open to or target international producers. As well as supporting domestic production, some governments are also implementing broader, trade-oriented policy frameworks in recognition of the crucial role of trade.

H2Global scheme, launched in December 2022, was the first competitive initiative specifically designed to support international trade in low-emissions hydrogen (see Chapter 6 Policies) through a double-auction scheme. The first EUR 900 million tender, funded by Germany's Federal Ministry for Economic Affairs and Energy (BMWE), was divided in 3 lots and offered 7-year supply contracts via Hintco, a subsidiary of H2Global Foundation, with 1-year demand-side auctions to follow closer to the delivery date of the product (Table 4.1). While ammonia attracted strong interest (22 bids), no final bids were submitted for the synthetic sustainable aviation fuel (SAF) lot, with participants raising concerns about the small lot size (EUR 300 million), short contract duration and regulatory uncertainty relating to renewable fuels of non-biological origin (RFNBO). These factors were seen as particularly risky for less-mature technologies, such as synthetic SAF. In response, Hintco revised the auction design and launched the consultation phase of a second tender in February 2025, allocating EUR 2.5 billion (potentially rising to EUR 3 billion).[43] The Netherlands and Germany will jointly open a vector-neutral tender for the import of hydrogen compliant with RFNBO regulation to Europe, whose application phase has not yet started. In addition, since the beginning of 2025, BMWE has committed up to EUR 588 million for bilateral H2Global tenders with Canada and Australia, where hydrogen production for export would take place. These tenders are currently undergoing EU state aid approval, and in July 2025 a public market consultation for the joint German-Canadian tender was launched. Natural Resources Canada (NRCan) pledged up to CAD 300 million (Canadian dollars) (USD 219 million) to co-fund the Canada–Germany tender, while Australia has an estimated AUD 33 million (Australian dollars) (USD 21 million) for 2028-29 in its 2025 Federal Budget, with further annual funding needed thereafter.

While not exclusively focused on trade, the EU Hydrogen Mechanism was launched in July 2025 under the European Hydrogen Bank. This market aggregation initiative may support export projects by collecting demand (from off-takers) and supply (including foreign suppliers) information to facilitate matches, with first calls planned for September 2025.

Contracts for Difference (CfD)[44] have been introduced in several countries to support domestic production (see Chapter 6: Policy), and in Japan and Korea are also being used to enable hydrogen imports. These schemes are designed to facilitate international supply chains and are complemented by broader infrastructure and import-enabling policies.

[43] During the first year, producers may offer non-firm volumes to facilitate ramp-up, while Hintco guarantees offtake for delivered quantities. Unused annual funds cannot be carried over, and full firm delivery must begin no later than 5 years after contract award.

[44] CfDs are a type of contract typically awarded through long-term auctions, that cover only the cost gap above a market reference price. They are well-established in the electricity sector.

Table 4.1 Government-backed mechanisms to support imports of low-emissions hydrogen and hydrogen-based fuels

Importing country	Product	Supplying regions	Status and description*
Germany	Ammonia compliant with EU RFNBO (≤3.38 kg CO_2eq/kg H_2, well-to-wheel)	Any outside EU/EFTA	Contract awarded. Part of H2Global's first import tender (Lot 1). Fertiglobe was awarded a EUR 397 million contract to supply 397 kt of ammonia (40 ktpa of guaranteed minimum offtake for 6 years) via the port of Rotterdam from Egypt's Ain Sokhna port from 2027 to 2033, at a fixed price† of EUR 1 000/t.
Germany	Methanol compliant with EU RFNBO	Any outside EU/EFTA	Contract under negotiation. H2Global's first import tender assigned EUR 300 million for Lot 2.
Germany	Synthetic SAF compliant with EU RFNBO	Any outside EU/EFTA	Tender cancelled. H2Global´s first import tender assigned EUR 300 million for Lot 3, with no final bids submitted.
Germany	Product-open compliant with EU RFNBO (H_2, ammonia or methanol)	Africa, Asia, North America and South America & Oceania	Tender opened in July 2025. H2Global's second import tender allocates at least EUR 484 million per lot across four regional lots for deliveries to a German hub between 2028 and 2036. Contracts are expected to be awarded by end-2026, with a price cap of EUR 11.75/kg H_2.
Germany, Netherlands	Vector-open‡ compliant with EU RFNBO	Global (other than Germany or the Netherlands)	Tender announced. H2Global's second import tender has at least EUR 567 million of joint funding from Germany and the Netherlands, for deliveries to a virtual trading point in their hydrogen network in 2028 - 2036.

Importing country	Product	Supplying regions	Status and description*
Korea	Low-emissions hydrogen and ammonia (≤4 kg CO_2eq /kg H_2, well-to-gate)	Global	Contract awarded. In 2024, MOTIE launched its first CHPS tender, offering 15-year CfDs for 6.5 TWh/year of low-emissions hydrogen-fired power, awarding a 750 GWh/year contract to KOSPO. Operations will begin in 2028, with ammonia imports for coal co-firing.
Korea	Low-emissions hydrogen and ammonia (≤4 kg CO_2eq /kg H_2, well-to-gate)	Global	Tender opened. In 2025, MOTIE launched a second tender under the CHPS scheme, offering 15-year CfDs for 3 TWh/year of low-emissions hydrogen-fired power to be operational by 2029.
Japan	Low-emissions hydrogen-based fuels (≤3.4 kg CO_2eq /kg H_2, well-to-gate)	Global	Tender closed, under evaluation. METI launched a USD 20 billion CfD auction for hydrogen-based fuels from domestic and overseas producers through 15-year contracts. Project selection will start on a rolling basis in 2025, with imports expected by 2030.

* Status as of July 2025. † The price includes the net product price (EUR 811/t ammonia), transport and logistics charges, and import and export duties. ‡ In the vector-open lot, hydrogen must be the final product, but the suppliers are free to choose any transport method (e.g. liquid organic hydrogen carriers [LOHC], ammonia) provided that the carrier is converted back to hydrogen before delivery.

Notes: CHPS = Clean Hydrogen Portfolio Standard; EFTA = European Free Trade Association; METI = Ministry of Economy, Trade and Industry (Japan). Well-to-gate emissions include those generated up to the point hydrogen leaves the production facility, while well-to-wheel emissions also account for transport, storage, and end-use.

In 2024, Korea's Ministry of Trade, Industry and Energy (MOTIE) launched a 15-year CfD tender to support low-emissions hydrogen-fired power generation and enable international hydrogen supply chains (see Chapter 2 Hydrogen demand). However, only 11.5% of the targeted capacity was awarded, as most bids exceeded an undisclosed price ceiling and concerns were raised over currency risks and certification procedures, among other aspects. In the second round, launched in 2025, MOTIE introduced changes including a settlement system to manage foreign exchange (forex) risk more effectively, a key concern in cross-border projects involving long-term agreements using different currencies. It also introduced a "volume carry-over system", allowing generators to offset production surpluses or shortfalls in one year in the following year.

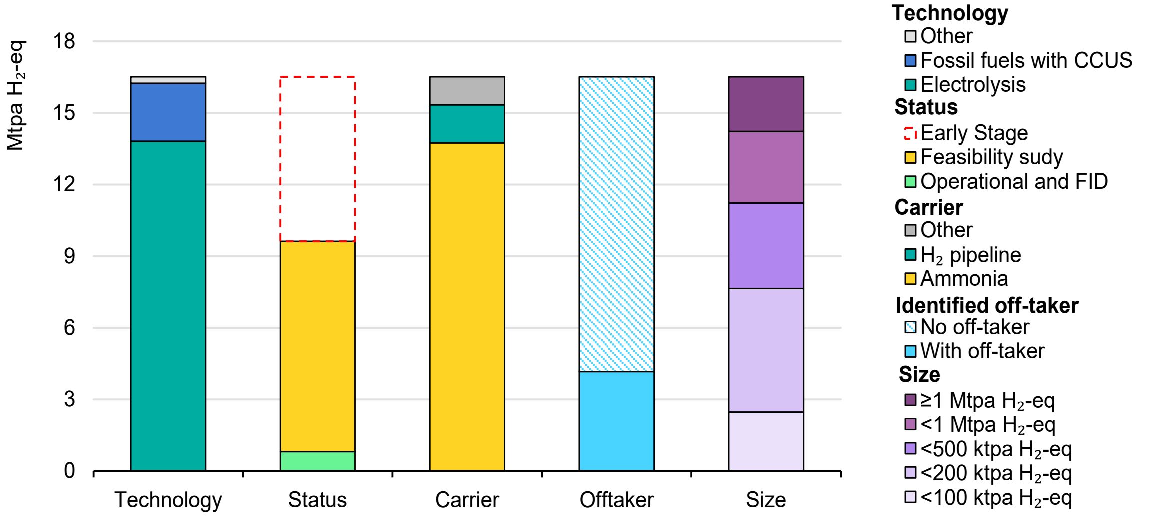
The global market remains uncertain, meaning that only a few announced projects will be realised by 2030

Export-oriented projects account for more than 16 Mtpa hydrogen equivalent (H_2-eq) by 2030, or about 45% of total low-emissions hydrogen production expected if all announced projects are realised. This highlights the important role of trade in driving project announcements, despite continued uncertainty around the development of a global hydrogen market. However, more than 40% of these export-oriented projects are still at very early stages and around 55% are undergoing feasibility studies. Only less than 5% of the potential traded volume – equivalent to 0.8 Mtpa H_2-eq – comes from projects operational, that have reached FID or are under construction. This compares to a 11% share of projects with committed investments (i.e. with FID, under construction or completed) in the total low-emissions hydrogen project pipeline by 2030.

Across all project types, the total committed production (i.e. operational or having reached FID) is 4.2 Mtpa H_2-eq by 2030, with export-oriented projects making up roughly 20% of that figure. This suggests that although trade is a major factor in project announcements, export-oriented projects are currently less likely to progress to investment stage.

Of all projects that have reached FID, export-oriented projects targeting electrolysis and fossil-based hydrogen with CCUS routes account for a similar share of around 20% each. However, investment drivers and import markets differ, as the role of fossil-based hydrogen with CCUS in Europe remains uncertain, while in Japan and Korea, such projects may be eligible for tenders, given that eligibility is based only on carbon footprint. Notably, Korea's first CHPS tender included an award for CCUS-based ammonia imports.

Figure 4.1 Announced projects for low-emissions hydrogen and hydrogen-based fuels intended for exports, 2030



Notes: CCUS = carbon capture, utilisation and storage; FID = final investment decision.
Source: IEA Hydrogen Production Projects Database (September 2025).

Around 45% of announced low-emissions hydrogen projects by 2030 target exports, but only one-quarter have identified off-takers and less than 5% have secured investment.

Several factors are limiting the progression of export-oriented projects towards FID:

- **Lack of off-takers**. Only one in four trade-oriented projects has identified a potential off-taker (Table 4.2), but offtake agreements are often necessary for FIDs (see Chapter 5 Investment and innovation). Regulatory uncertainty and the absence of clear definitions for low-emissions fuels further limit offtake commitments.
- **Large project scale.** Export-oriented projects tend to be larger, as dedicated export infrastructure is only economically viable when used at scale. Among all projects that have reached FID, 90% have a planned production below 200 ktpa H_2. In contrast, more than 50% of announced trade-oriented projects are above this threshold. First-of-a-kind, larger-scale projects are often perceived as riskier, hindering progress to FID. To date, two large projects, NEOM's ammonia project in Saudi Arabia and Greenko ZeroC in India, account for nearly 70% of low-emissions hydrogen trade volumes from electrolysis projects that have taken FID.
- **Infrastructure readiness**. Around 85% of trade-oriented projects plan to transport hydrogen as ammonia, i.e. 13.7 Mtpa H_2-eq, equivalent to more than 75 Mtpa of ammonia. This volume is significant compared to current global ammonia production of roughly 200 Mtpa and is nearly 4 times larger than the ammonia traded today (20 Mtpa). A sharp increase of this scale would require a rapid, large-scale expansion of ammonia handling infrastructure at ports, which may face physical, regulatory and timing constraints. It would also require substantial new demand creation, including for ammonia cracking, which is still in the early stages of commercial validation.
- **High concentration in emerging economies**. Almost 60% of trade-oriented projects are located in emerging markets and developing economies (EMDEs), excluding China (Figure 4.2), where limited infrastructure, regulatory uncertainty and a high cost of capital may delay FIDs.

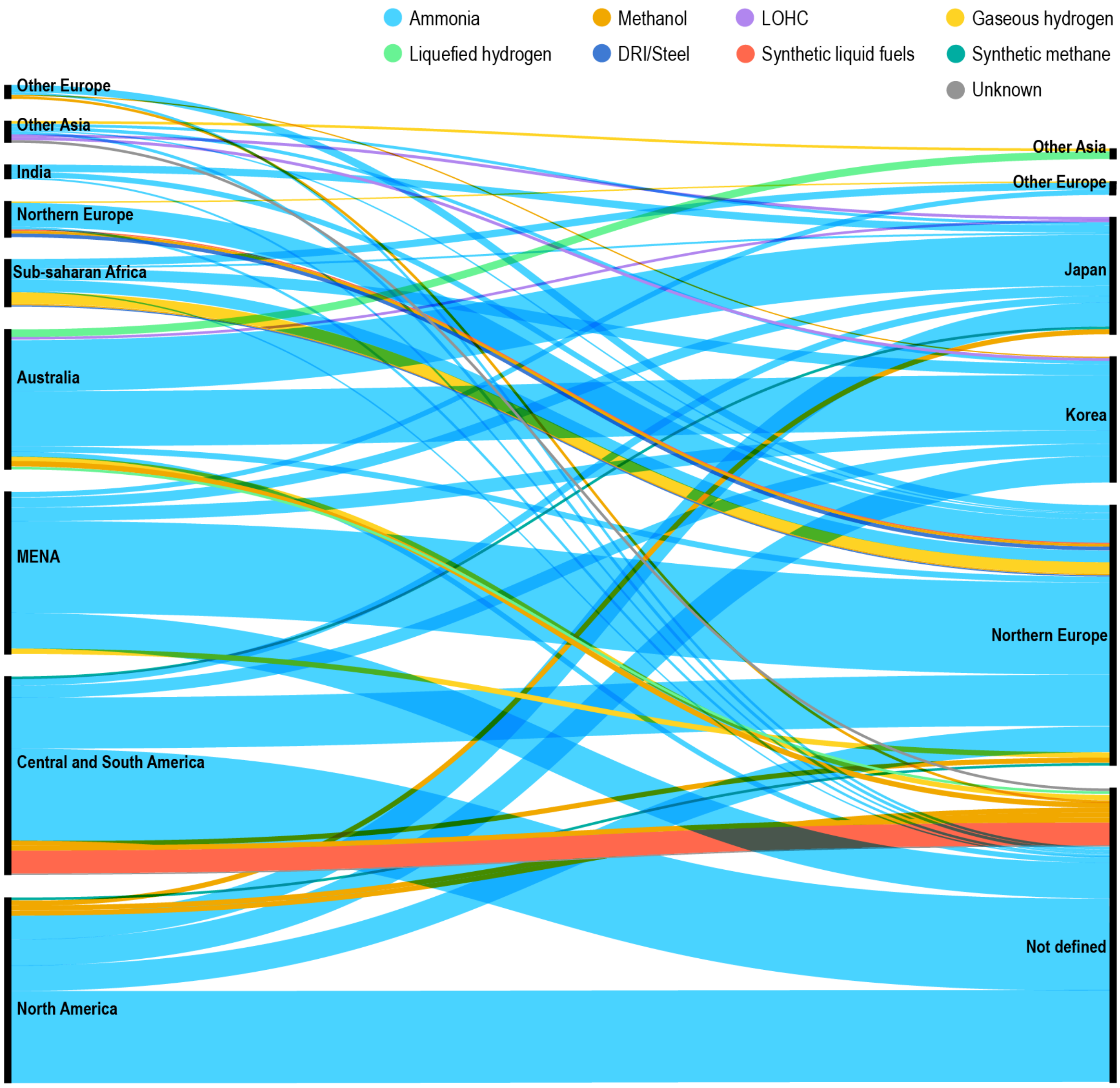
Table 4.2 Selected projects for low-emissions hydrogen fuels and derived products targeting exports with offtake agreements

Project & Export country	Product	Trade-oriented off-takers & Import region	Description
Hyphen, Namibia	Ammonia	RWE, Approtium, Other chemical company (Germany, Korea)	Non-binding offtake agreements for ~1 Mtpa ammonia, with first exports expected by 2027.
ACME Oman project, Oman	Ammonia	Yara, (Global)	Binding offtake agreement for 100 ktpa ammonia by 2027.

Project & Export country	Product	Trade-oriented off-takers & Import region	Description
H2-hub Gladstone Australia	Ammonia	Korea East-West Power, MHI (Japan, Korea)	Long-term non-binding offtake agreements, with exports expected by 2027.
ACME Odisha plant, India	Ammonia	IHI (Japan)	Non-binding offtake agreements for up to 400 ktpa ammonia for power generation from 2028.
Egypt Green Hydrogen	Ammonia	Fertiglobe, (Global, part will be shipped to the Netherlands as part of H2Global)	20-year offtake agreement (Fertiglobe has already allocated part of this volume through H2Global to Hintco).
NEOM Green Hydrogen, Saudi Arabia	Ammonia	Air Products (Global)	Binding 30-year offtake agreement for 1.2 Mtpa ammonia (exclusive off-taker), expected from 2027. Air Products does not intend to act as a retail marketer and instead plans free on board sales via partners.
ATOME La Villeta, Paraguay	Calcium ammonium nitrate	Yara (Global)	Non-binding offtake agreement for 260 ktpa (exclusive off-taker), expected to begin by 2027.
Stegra, Sweden	Steel	Mercedes-Benz, Cargill Metals, Lindab, BMW, others. (Europe)	Binding multiyear offtake agreements with more than 20 customers (most commonly 5-7 years) for ~1.5 Mtpa steel, with a 25% premium cost.
DG Fuels, United States	Aviation fuel	Air France-KLM (International aviation)	Offtake agreement for 600 ktpa of sustainable aviation fuel, to be delivered between 2027 and 2036, securing a further 75 ktpa from 2029.
HyIron Oshivela, Namibia	DRI	Benteler (Germany)	Offtake agreement for 200 ktpa DRI, expected to start operations by 2026.

Notes: DRI = Direct Reduced Iron; MHI = Mitsubishi Heavy Industries. "Free on board" means the seller is responsible for delivering and loading the product onto a tanker, after which the buyer assumes all costs and risks, including shipping, insurance and onward transport.

Figure 4.2 Bilateral trade flows of low-emissions hydrogen by carrier, excluding projects at earlier stages, 2030



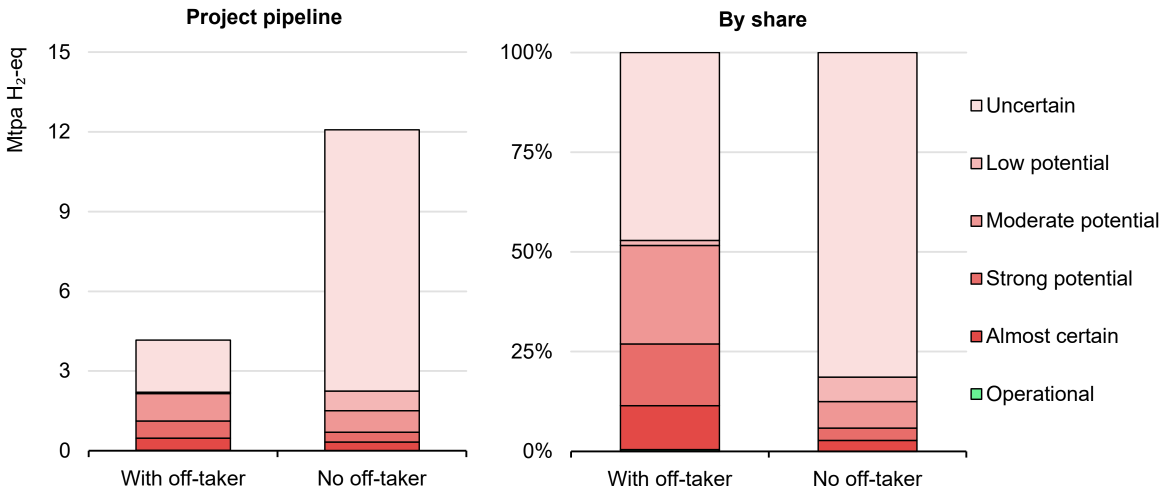
Notes: HBI = hot briquetted iron; LOHC = liquid organic hydrogen carrier. "Not defined" refers to projects for which the import destination has not been identified or disclosed. Earlier-stage projects that are not included are those that remain at the conceptual stage and have not yet progressed to feasibility studies. Total traded volume represented in the diagram corresponds to 9.6 Mtpa H_2-eq by 2030.

Source: IEA Hydrogen Production Projects Database (September 2025).

Most low-emissions hydrogen trade projects target exports to Europe, mainly to Germany and the Netherlands, or to Japan and Korea, while one-third have no specified destination.

The methodology developed to evaluate how much low-emissions hydrogen production could feasibly be operative by 2030 (Box 3.1) has been applied to projects targeting exports. For trade-oriented projects, those that are either already operational or almost certain, i.e. under construction or having reached FID, represent just above 0.8 Mtpa H_2-eq by 2030. An additional 1 Mtpa H_2-eq has strong potential to be traded within this timeframe, provided that the cost gap with domestic hydrogen production in importing countries is closed, off-takers are secured, and delivery infrastructure is in place. Necessary infrastructure includes port handling and, where reconversion into hydrogen is required, infrastructure such as ammonia crackers, along with available appropriate shipping tankers.

Figure 4.3 Likelihood of low-emissions hydrogen trade projects with an identified off-taker or with no off-taker being available in 2030



Note: "With off-taker" includes projects that have an identified off-taker and an agreement in place, and projects with an identified off-taker but no agreement in place.
Source: IEA Hydrogen Production Projects Database (September 2025).

Only around 0.8 Mtpa H_2-eq is almost certain to be traded by 2030; the potential of other projects is dependent on off-takers and enabling export infrastructure.

An additional 1.8 Mtpa H_2-eq has moderate potential to be traded by 2030, but achieving that potential will depend on stronger policy support to increase demand in importing countries, where trade can help meet hydrogen needs more cost-effectively while also diversifying supply sources for greater energy security. However, more than 75% of the announced volume from trade-oriented projects in the pipeline has low potential or is uncertain to become operational before 2030. Most of this volume is associated with large-scale electrolysis projects in EMDEs, where abundant renewable resources offer theoretical advantages, but these are often offset by high costs of capital, a lack of off-takers and underdeveloped port infrastructure, among other challenges. The scale and complexity of these projects suggest that many may not proceed or are more likely to be commissioned only after 2030, with the first operations expected between 2035 and 2040, depending on the pace of global trade development.

Status and perspectives for hydrogen infrastructure

Transport by pipeline

Building the backbone for hydrogen transmission requires updated pipeline standards

Around 5 000 km of hydrogen pipelines are in operation worldwide, primarily connecting refineries and chemical facilities. These pipelines are typically privately owned, located onshore, and designed for relatively short-distance transport using small-diameter pipes operating at low pressure under steady flow conditions. In contrast, planned future hydrogen transmission systems look markedly different. Pipelines may be regulated as open access, feature larger diameters and operate at higher pressures, spanning both onshore and offshore routes. They would offer greater operational flexibility, including the ability to manage pressure swings that may result from load fluctuations and linepack storage. While some pipelines will serve as regional distribution lines, particularly in the early phases, to link supply and demand in proximity, most of the total announced length would function more like natural gas transmission systems. However, hydrogen networks are expected to follow a more centralised layout, built around high-capacity trunklines connecting major production and demand centres, with some branches to key industrial hubs.

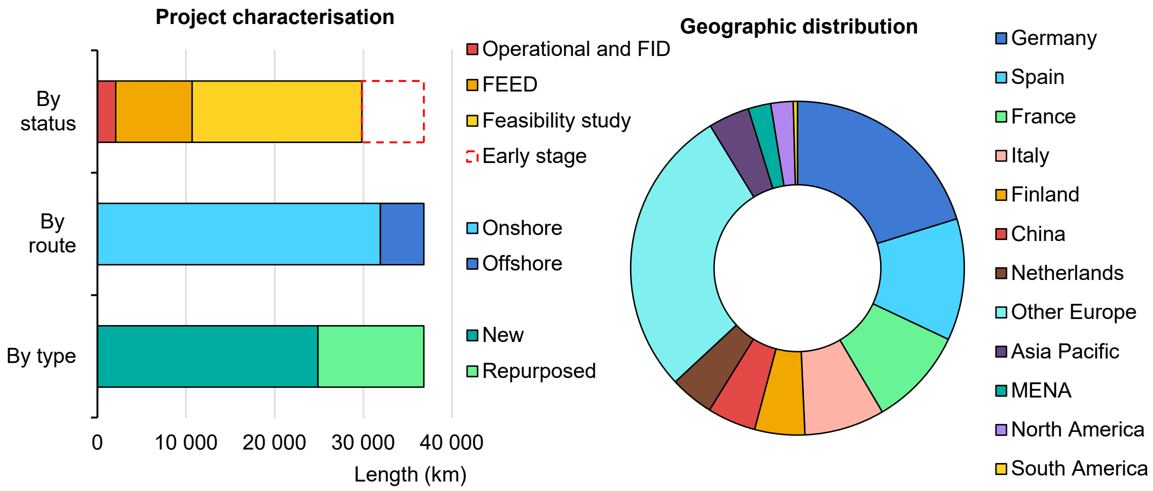
This shift is also reflected in evolving pipeline standards. Today's hydrogen pipelines are often designed under the American Society of Mechanical Engineers (ASME) B31.12 standard, originally developed for short-distance, small-diameter onshore pipelines. While this standard addresses hydrogen embrittlement,[45] it is widely regarded as overly conservative for future high-pressure transmission, particularly for repurposed natural gas pipelines. In response, there are plans to integrate hydrogen-specific requirements into the broader ASME B31.8 gas transmission and distribution standard update for 2026, supported by a Consensus Engineering Requirements project completed in 2024. This update aims to streamline hydrogen pipeline design, facilitate repurposing of existing infrastructure and harmonise regulations relating to different gases.

[45] Hydrogen embrittlement occurs when hydrogen atoms are absorbed into steel, reducing its ductility and making it more susceptible to cracking. This can accelerate fatigue crack growth and reduce the lifespan of pipelines.

World's longest and largest-diameter hydrogen pipelines are now under construction in China and Europe, despite delays

Natural gas transmission pipelines span around 1.1 million km globally, with an additional 80 000 km under construction and 160 000 km under consideration. In contrast, announced hydrogen pipeline projects, including new pipelines and repurposed natural gas pipelines, total around 37 000 km by 2035. However, less than 6% of this (by length) has reached FID or is under construction, which is equal to 2.7% of the natural gas pipelines currently being constructed. If all announced hydrogen pipeline projects proceed, they would represent about 3.4% of the current global gas transmission network. While small in relative terms, the pace of growth is significant: natural gas transmission pipelines have expanded at an average of 15 000 km per year over the past 40 years, with an acceleration in the last decade.

Figure 4.4 Global hydrogen transmission pipeline length based on announced projects by type and region, 2035



Notes: FEED = front end engineering design; FID = final investment decision; MENA = Middle East and North Africa. While 2030 is generally used as the reporting year throughout this report, 2035 is used for infrastructure developments to reflect longer lead times required for their planning and construction. More details on announced projects for hydrogen pipelines can be found in the new Hydrogen Tracker on the IEA website.

Source: IEA Hydrogen Infrastructure Projects Database (September 2025).

Of the 37 000 km of hydrogen pipelines announced by 2035, a third involves repurposing, but less than 6% of the total length has at least reached FID, with most projects in Europe.

Announced plans for hydrogen pipelines remain geographically concentrated, particularly in Europe. For example, the length of hydrogen transmission pipelines in the Netherlands would be equivalent to over 10% of the country's existing natural gas transmission network, and in Germany and Spain, it would be more than 20%. Importantly, these networks were built over more than 45 years, while plans for hydrogen infrastructure target development within less than a decade.

Northwest Europe has made notable progress on hydrogen pipeline infrastructure since the Global Hydrogen Review 2024 was published. In October 2024, the German Federal Network Agency (BNetzA) approved the construction of the 9 040 km national hydrogen network, to be completed by 2032. That same month, Gascade took FID on the northern section of the 400 km Flow – Making Hydrogen Happen (East) project. In March 2025, it began repurposing 1.4-metre diameter natural gas pipelines[46] – the world's first repurposing at this scale – targeting commissioning by end-2025. Regional and industrial networks that will connect with the national core network are also progressing. In central Germany, ONTRAS completed hydrogen-filling of a 25 km repurposed pipeline in April 2025, for test operations. In Lower Saxony, Nowega began hydrogen-filling of the first 55 km of the GET H2 Nukleus project, with 95% repurposed pipelines. In June 2025, as part of the broader GET H2 project in neighbouring North Rhine-Westphalia, Evonik completed a 55 km hydrogen pipeline, 75% repurposed, connecting one of the largest chemical park in Germany to a refinery. In Hamburg, construction of the 60 km HH-WIN industrial hydrogen network began in February 2025, with the first 40 km expected to be operational by 2027. In Belgium, Fluxys began construction in March 2025 on the first phase of the national hydrogen pipeline network, connecting the port areas of Antwerp and Ghent via 35 km of newly built pipelines, although construction was halted a month later (see below). Hydrogen pipeline construction in the Netherlands is progressing, despite delays to the full national network. The first 30 km section in Rotterdam, under construction since October 2023, remains on track to begin operations by 2026 as initially planned. In early 2025, Gasgrid awarded front-end engineering design (FEED) contracts for Finland's planned 1 100 km hydrogen network, Enagás launched pre-FEED studies[47] for Spain's 2 600 km network, while in Denmark Energinet opened an Engineering, Procurement and Construction Management tender for the 133 km Esbjerg – Egtved – Frøslev section, which will connect to Gasunie Deutschland.

In China, construction of the approximately 1 000 km Kangbao (Zhangjiakou) – Caofeidian (Tangshan) hydrogen pipeline in Hebei Province is expected to begin in 2025, following completion of temporary land use procedures in April 2025, with operations targeted by the end of 2026. The pipeline, with an approximate diameter of 0.8 m, will operate at around 70 bar, which is well above China's current 40 bar standard for hydrogen, enabling higher capacity for hydrogen transport. In early 2025, Inner Mongolia, China, launched a bid for feasibility studies on a 4 400 km network comprising hydrogen, methanol and ammonia pipelines. This includes 10 hydrogen pipelines connecting production sites to ammonia plants, anchored by an 800 km trunkline between Ordos and Chifeng (both in Inner Mongolia). It also features two pipeline rings within these hubs, and

[46] A pipeline of this diameter would be capable of transporting over 2 Mtpa H_2 when operating at 80 bar and at 75% of its nominal design capacity, assuming 5 000 full-load operating hours per year.
[47] Awarding a EUR 70 million contract to several engineering firms.

multiple branch lines supplying industrial areas, as well as Hebei (via the Kangbao –Caofeidian pipeline), Shaanxi, Ningxia and Liaoning. While large-scale construction is unlikely to begin before 2026, authorities have already approved an initial 85 km hydrogen pipeline in Chifeng (Aohan-Yuanbaoshan) with a planned capacity of 210 ktpa. In July 2025, Sinopec approved China's first cross-provincial hydrogen pipeline, spanning 400 km from low-emissions hydrogen production sites in Inner Mongolia to the Beijing–Tianjin–Hebei region. In August 2025, the China Huadian Group launched a tender for the construction of a 195 km hydrogen pipeline in Inner Mongolia with a capacity of 100 ktpa H_2.

Outside Europe and China, announcements remain limited, but Oman's gas network operator OQGN plans to take FID in 2027 on a 300-400 km hydrogen pipeline, starting with regional pipelines before expanding nationally. Engineering firm Wood was contracted to complete pre-FEED work by 2025. A project in Indonesia's Riau Islands, targeting the transport of around 110 ktpa H_2 to Singapore via a ~40 km offshore pipeline, has entered the FEED phase. The European Union has granted EUR 3 million to BOTAŞ, Türkiye's state-owned pipeline operator, to assess the technical suitability of repurposing existing infrastructure for hydrogen and to develop a national hydrogen network master plan.

Developing cross-border hydrogen pipelines requires strong international co-operation and political will, as projects must navigate multiple jurisdictions. One of the most well-established initiatives is the European Hydrogen Backbone, launched in 2020, which now consists of 33 energy infrastructure operators across Europe. Other recent efforts are helping to transform high-level ambitions into structured co-operation. In January 2025, Italy, Germany, Austria, Algeria and Tunisia signed a Joint Declaration of Political Intent, reaffirming their political and institutional commitment to advancing the SouthH$_2$Corridor, a planned 3 300 km hydrogen pipeline linking North Africa to Central Europe. In May 2025, UK National Gas and Germany's Gascade signed a Memorandum of Understanding (MoU) to assess a potential offshore hydrogen pipeline across the North Sea, building on findings from a feasibility study under the United Kingdom-Germany hydrogen partnership.

Securing the enablers for hydrogen networks: demand certainty, finance and social licence to operate

The rollout of hydrogen transmission infrastructure has been slower than initially planned, reflecting both broader delays in low-emissions hydrogen deployment and specific challenges related to the development of gas transmission grids. Planning such infrastructure is inherently complex, as construction timelines often exceed those of the supply and demand projects they aim to link. This requires infrastructure investment decisions to be made before connected projects reach

FID. A key consideration is balancing the long-term potential for hydrogen transport with the continued short- to medium-term need for natural gas, particularly when evaluating options to repurpose existing pipelines. A number of projects have faced challenges during the past year:

- **Belgium's Ghent–Antwerp hydrogen pipeline** faced delays after the Flemish Council for Permit Disputes suspended the project's environmental permit, following appeals from fruit growers over per- and polyfluoroalkyl substances (PFAS) discharges into water. Fluxys estimates the process may take up to a year.
- In October 2024, Danish transmission system operator Energinet delayed the **Denmark-Germany hydrogen pipeline** from 2028 to end-2031 at the earliest, for multiple reasons, including an environmental impact assessment now expected to take 40 months, compared with the initial estimate of 18 months. In December 2024, the Danish Energy Agency cancelled its entire 6 GW North Sea offshore wind tender after receiving no bids for the first phase, with investors raising concerns including uncertainty over the pipeline, seen as critical to using offshore wind power for electrolysis for hydrogen exports. In January 2025, the government committed additional public funding for the pipeline, targeting commissioning by 2030.
- The **Delta Rhine Corridor** between the Netherlands and Germany initially planned a multi-pipeline bundle for hydrogen, natural gas, CO_2, ammonia, liquefied petroleum gas (LPG), propylene, and underground DC power cables. Due to technical and financial challenges, the scope was narrowed to three pipelines (hydrogen, CO_2, ammonia) and DC cables, but combining pipelines and power cables proved too complex. In December 2024, the Dutch government reprioritised the project to focus solely on hydrogen and CO_2 pipelines, limiting the delay to 4 years, with commissioning now expected by 2032.
- In the **Netherlands**, completion of the national hydrogen backbone has been delayed by 3 years to 2033. Gasunie cited longer permitting timelines under the new Dutch Environment and Planning Act, which requires more extensive public consultation, unforeseen interdependencies between permitting and engineering (such as environmental and archaeological studies affecting pipeline design), and shortages of qualified staff.
- In September 2024, **Norway**'s Equinor halted plans for a 10 GW (2.6 Mtpa H_2) **offshore pipeline to Germany**, citing high costs (EUR 4-6 billion) and lack of demand. A joint Gassco-Dena study had confirmed technical feasibility, but the business case was deemed insufficient to proceed.

Market assessments play a critical role in breaking the deadlock between development of accessible infrastructure and demand certainty. As seen in Denmark, hydrogen suppliers and upstream power producers are hesitant to commit without guaranteed infrastructure, while pipeline development is held back by the lack of firm demand, as was the case with the planned offshore pipeline between Norway and Germany. Calls for interest are being used to address this challenge by collecting information from both prospective hydrogen producers and buyers (Table 4.3). These assessments help define the necessary transmission capacity in terms of location, volume and timing, providing inputs for the routing and sizing of hydrogen networks, and eventually for binding capacity bookings that enable projects to move towards FID. In Denmark, aligning pipeline development with market demand has proved challenging. Initial state support required bookings of at least 1.4 GW, equivalent to 44% of capacity, (around 210 ktpa H_2, assuming 5 000 full-load operating hours per year) over 10–15 years for the pipeline to Germany. In early 2025, this threshold was lowered to 0.5 GW (75 ktpa H_2) to allow the project to advance, based on commitments from a single potential hydrogen producer.

Table 4.3 Market surveys and capacity bookings for selected hydrogen transmission projects, Q3 2024 – Q2 2025

Project	Length (km)	Organisers	Description
mosaHYc France – Germany	94	NaTran, Creos Deutschland	Binding capacity booking; SHS steelmaker has booked 50 ktpa H_2, equivalent to 80% of the pipeline's capacity, for 25 years under a take-or-pay agreement.
Belgium – France (Dunkirk)	150	Fluxys, NaTran	Non-binding call for interest; 30 respondents, ongoing clarification meetings and results expected in 2025.
Belgium – Germany (Eynatten)	~320	Fluxys, OGE	Non-binding call for interest; 30 respondents, ongoing clarification meetings and results expected in 2025.
H2med corridor (Spain, Portugal, France, Germany)	~5 500	Enagás, REN, Térega, NaTran, OGE	Non-binding call for interest, 170 respondents, CelZa (PT–ES): 0.4 Mtpa H_2 demand by 2030 (capacity 0.75 Mtpa); BarMar (ES–FR): 1.2 Mtpa by 2030 (capacity 2 Mtpa, full by 2032); HY-FEN (FR–DE): up to 50% of H2med by 2035; North Africa: transit interest post-2040
Get H2 Nukleus (Germany)	130	Nowega, OGE, Thyssengas	Network access contract published. This introduces a two-part model for booking both fixed and freely allocable capacities, with an energy balancing contract under development.
Italian H_2 backbone (Italy)	2 300	Snam	Non-binding call for interest; 101 respondents. Average 2031-2040 demand: domestic (IT): 0.6 Mtpa H_2; transit to AT&DE: 1.6 Mtpa H_2.

Notes: AT = Austria; DE = Germany; ES = Spain, FR = France; PT = Portugal.

Large-scale hydrogen infrastructure requires substantial upfront investment, even while early demand is uncertain. Pipelines offer significant economies of scale: constructing a 2 Mtpa (48-inch/1.2 m) pipeline costs less than 3 times more than a 150 ktpa (20-inch/0.5 m) pipeline, while providing nearly 15 times the capacity. For repurposed pipelines, where the main asset is already in place, investments can be as low as one-fifth of those for new hydrogen pipelines. Given long lead times and initially limited demand, pipeline networks are typically oversized to accommodate expected utilisation growth.

To mitigate investment risks, several countries are now introducing dedicated financial mechanisms (see Chapter 6 Policies). Germany has established a EUR 24 billion amortisation account, backed by a state loan, enabling early network development while users pay stable network fees, with repayment targeted by 2055. Germany's Federal Network Agency has set the ramp-up tariff at EUR 25/kWh/h per year, which corresponds to the annual fee for booking 1 kW of pipeline capacity. In many other jurisdictions, financing models and the role of public support are still under discussion, influencing the pace of FIDs. At the EU level, approximately EUR 250 million was allocated in 2024 from the Connecting Europe Facility (CEF) for grants for feasibility studies, including the BarMar-H2Med interconnection between Spain and France, the backbone projects in Italy, Portugal and Spain, and the hydrogen corridors and routes in the Baltic region. In June 2025, the United Kingdom allocated GBP 500 million (~EUR 590 million) for hydrogen transport and storage infrastructure, though details on the funding mechanism are still to be confirmed at the time of writing.

Market calls for interest and public consultations play complementary roles in reducing the investment risks associated with hydrogen infrastructure development. Calls aimed at commercial actors can help assess potential demand, attract investment, and inform project sizing and design. Public consultation and information-sharing is particularly important to secure a social licence to operate, as public opposition – including legal challenges – can delay or halt projects even after permitting. In Belgium, the Ghent–Antwerp pipeline is facing delays following environmental litigation, despite permit approval. To mitigate such risks, pipeline developers are strengthening early stakeholder engagement. The Netherlands' Delta Rhine Corridor initiated consultations with regional authorities early in the planning phase, including water authorities. In the United Kingdom, Cadent conducted statutory consultations in-person and online for its HyNet North West hydrogen pipeline. Enagás in Spain launched a Public Participation Plan for its hydrogen backbone, covering 550 municipalities. In France, NaTran organised five public information meetings for the mosaHYc project. Early and transparent consultation will remain essential to enable timely project delivery, particularly for pipelines that cross multiple jurisdictions.

Table 4.4 Estimated investment needs for selected hydrogen pipeline projects, 2025

Project	Length (km)	Estimated investment*	Finance source
Hydrogen backbone (Germany)	9 040	EUR 18.9 billion	First loan payment of EUR 172 million from KfW to the amortisation account.
Hydrogen backbone (Netherlands)	1 200	EUR 3.8 billion	Cost estimate raised to EUR 3.8 billion (2025) from EUR 1.5 billion (2021) due to fewer repurposing possibilities, higher material and labour costs and an expansion of the original plan.
Hydrogen backbone (Spain)	2 600	EUR 4.2 billion†	EUR 40 million for feasibility studies from the EU CEF.
H2med CelZa (Portugal, Spain)	248	EUR 350 million	EUR 35 million for feasibility studies from the EU CEF.
H2med BarMar (Spain, France)	450	EUR 2.1 billion	
Syvtal (Denmark)	360	EUR 2.0 billion (under review)	EUR 1 billion state loan for pipeline to German border; up to EUR 1.1 billion in operational subsidies (for 30 years).
mosaHYc (France – Germany)	94	EUR 110 million	NaTran (France) will invest 35% and Creos Deutschland 65%.
H_2HighwayZBB XL (Belgium)	97	EUR 300 million	EUR 95 million from EU Recovery and Resilience fund via the Belgian government for first phase.
HH-WIN (Germany)	60	EUR 223 million	IPCEI project, co-financed by the European Union and the German Senate.
Zhangjiakou - Caofeidian pipeline (China)	~1 000	USD 850 million	[Information not available].
Chifeng pipeline (China)	85	USD 60 million	[Information not available].

* As of information available in May 2025. † This figure also includes certain investments in underground hydrogen storage facilities, in addition to pipelines, as part of the broader hydrogen infrastructure backbone.

Note: IPCEI =Important Projects of Common European Interest.

Box 4.1 How much hydrogen is leaking and what does it mean for the climate?

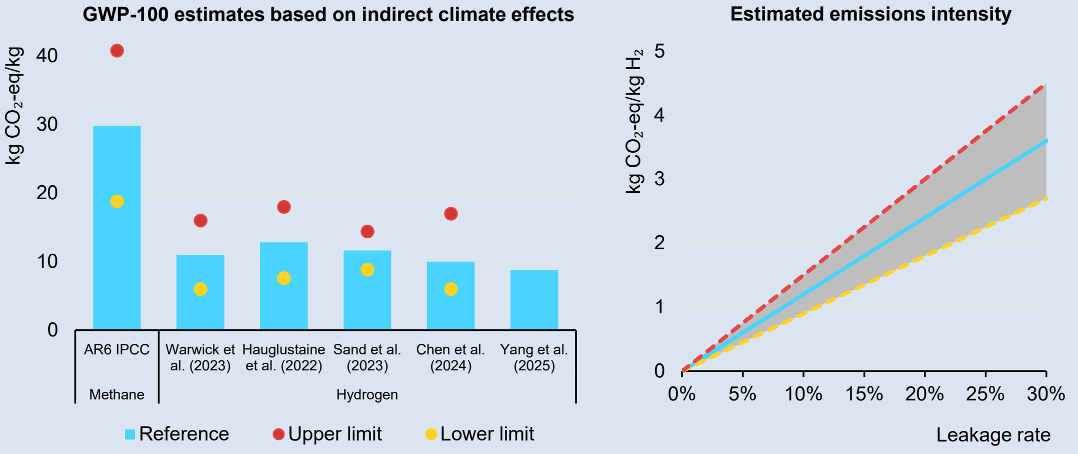
Hydrogen is not a GHG as it does not absorb infrared radiation, but when released into the atmosphere, it can indirectly contribute to climate change due to atmospheric reactions that affect the concentrations of certain GHGs. The scale of this impact depends on two key uncertainties: leakage rates across the hydrogen supply chain and the resulting effects on atmospheric chemistry.

Hydrogen's indirect climate impact occurs mainly through three mechanisms: (1) reaction with hydroxyl radicals (OH) which extends the lifetime of methane (CH_4); (2) reaction with oxygen, contributing to tropospheric ozone (O_3) formation; and (3) increasing water vapour levels in the stratosphere. Hydrogen does not have a Global Warming Potential (GWP) assigned by the Intergovernmental Panel on Climate Change (IPCC); however, atmospheric chemistry model studies incorporating these three indirect climate effects have attributed a GWP of 12±3 over 100 years (GWP-100). A 2025 study, incorporating updated estimates of atmospheric OH levels and reactivity, suggests a GWP-100 approximately 20% lower.

Uncertainty remains in model-derived estimates of hydrogen's climate effects, due in part to limited understanding of key atmospheric processes, such as global OH concentrations, their reactivity, and the relative importance of OH versus soil uptake as hydrogen sinks. Additional uncertainty arises from the dependence of indirect effects on atmospheric conditions and the concentration of other GHGs, such as methane. For instance, since hydrogen reduces OH availability and can extend methane's lifetime, any change in methane concentrations would also change the climate impact of hydrogen.

Given hydrogen's small molecular size, high diffusivity, and low resistance to flow, it is particularly prone to leakage across the supply chain, especially during transport, handling and use, with liquefied hydrogen showing the highest estimated losses in some studies due to boil-off, though strategies exist to minimise and recover these losses. Real-world field measurements of hydrogen leakage remain very limited, with most available data based on theoretical models or extrapolated from natural gas systems that have not yet been validated. In October 2024, the first study measuring industrial hydrogen emissions from production and storage reported median leakage rates of 1-2%. A theoretical study had previously summarised hydrogen leakage rates ranging from 0.2% to 20.0%, highlighting the wide range of possible outcomes. However, due to the limited availability of empirical data, estimates vary widely, and significant uncertainties remain regarding total leakage rates and the parts of the supply chain that present the highest risks and require targeted mitigation efforts. When assuming a GWP-100 value in the upper uncertainty range from the literature (12+3), leakage rates above 13% could result in emissions intensities exceeding 2 kg CO_2-eq/kg H_2. However, given the cost of low-emissions hydrogen, high leakage rates would not only induce climate impacts, but also compromise the economic viability, providing a strong incentive to minimise losses across the supply chain.

Attributed GWP-100 of hydrogen from atmospheric chemistry models and corresponding emission intensities at varying leakage rates



Note: The right-hand figure uses a GWP-100 value of 12 as reference, with ±3 as the upper and lower bounds.

Sources: IPCC (2021) Sixth Assessment Report Global Warming Potentials, Warwick et al. (2022), Hauglustaine et al. (2022), Sand et al. (2023), Chen et al. (2024), Yang et al. (2025).

Reducing hydrogen leakage requires a combination of advanced materials, improved infrastructure design, effective monitoring systems and supportive regulatory frameworks.

Advanced materials and infrastructure design play a critical role in minimising and containing hydrogen leaks. Specialised coatings and sealants, such as high-performance polymers and composites, help limit permeation in storage tanks, pipelines and equipment. Multi-layered safety barriers and optimised infrastructure design further enhance containment and reduce potential leaks.

Early detection and repair. Industry is starting to implement leak detection and repair programmes specifically targeting hydrogen leaks. However, suitable detection technologies are still limited. Most sensors have been developed primarily for safety, focusing on detecting large, potentially explosive leaks rather than accurately measuring small emissions. Conventional sensors are typically designed to detect hydrogen concentrations near its lower flammability limit of 4% (40 000 ppm), with lower detection thresholds often in the ppm range, such as Honeywell's Hydrogen Leak Detector, with a threshold of 50 ppm. However, detecting much lower concentrations, in the parts-per-billion (ppb) range, is needed to quantify supply chain emissions and assess their potential climate impact. Recent developments in hydrogen detection have enabled sensors with ppb level sensitivity and fast response times, though further innovation is needed for broader deployment of these ultra-sensitive sensors in a cost-efficient manner.

Enabling regulatory frameworks. The absence of internationally agreed standards for measuring hydrogen leaks remains a challenge, limiting data comparability and slowing mitigation efforts. Given hydrogen's different physical properties compared to methane, existing methane regulations may require adaptation. Several national and international initiatives are underway to develop dedicated measurement protocols and safety standards tailored to hydrogen:

- The European Network of Network Operators for Hydrogen has proposed draft rules promoting best practices and international co-operation on hydrogen leak management standards.
- The Pre-normative Research on Hydrogen Releases Assessment (NHyRA), an EU-based project involving stakeholders from 9 countries, is adapting methane regulations for hydrogen by revising detection methods, assessing technologies, identifying leak points and developing leakage scenarios.
- The EU-funded HYDRA project assesses the climate impacts of hydrogen using atmospheric modelling, and develops improved monitoring tools and mitigation guidelines for leakage.
- In the United States, the Clean Air Task Force has suggested a framework combining safety, data collection, agency co-ordination and public access to hydrogen emissions information.
- An international research initiative is measuring hydrogen emissions from infrastructure in North America and Europe, with participation from industry (Air Products, Air Liquide, Shell, TotalEnergies), the Environmental Defense Fund and research institutions, with field measurements ongoing since March 2025.

Underground hydrogen storage

Underground hydrogen storage is advancing in technological readiness

Underground storage plays an important role in natural gas systems, providing a buffer to manage seasonal demand fluctuations and supply disruptions. Global underground gas storage capacity stands at around 490 bcm, equivalent to almost 12% of annual gas demand. In Europe, underground gas storage capacity is today equivalent to nearly one-third of consumption,[48] and is large enough to accommodate peak winter demand. Approximately 90% of the global capacity is

[48] This ratio was not intended by design, as natural gas consumption peaked in 2010 at levels around 30% higher than those seen today. This implies that the storage-to-demand ratio was lower at that time.

in porous reservoirs, mainly depleted gas fields. For hydrogen, underground storage is expected to serve a different function. In the near term, it would provide short-term flexibility[49] to balance variable production. As hydrogen markets scale up, storage may also contribute to energy security by mitigating supply risks and price volatility, including vulnerabilities that may arise from geopolitical tensions, with countries determining appropriate storage levels based on national circumstances.

Technological readiness for underground hydrogen storage is advancing across multiple geological options, supported by recent demonstrations. Salt caverns offer high operational flexibility where geological conditions allow, with higher investment costs offset by frequent cycling that lowers levelised storage costs. In May 2025, the HyPSTER project in France announced the successful completion of fast-cycling testing, with larger-scale fast-cycling demonstrations planned from 2027 in salt caverns in France and Germany under the FrHyGe project. The world's largest underground hydrogen salt cavern facility, the ACES Delta project, is under construction in Utah, United States.

Lined hard rock caverns can be developed in a wider range of geologies, require less cushion gas and offer greater flexibility, albeit at higher investment costs. Results from the HYBRIT project in Sweden, published in February 2025, demonstrated successful hydrogen storage in a 100 m³ lined hard rock cavern (around 70 MWh H_2, equivalent to 2 t H_2 at 250 bar). Commercial-scale facilities are expected to reach up to 120 000 m³ in cavern size (~70 GWh/2 kt H_2 at 250 bar), equivalent to the sizes of lined hard rock caverns used for natural gas storage in Sweden and the Czech Republic today.

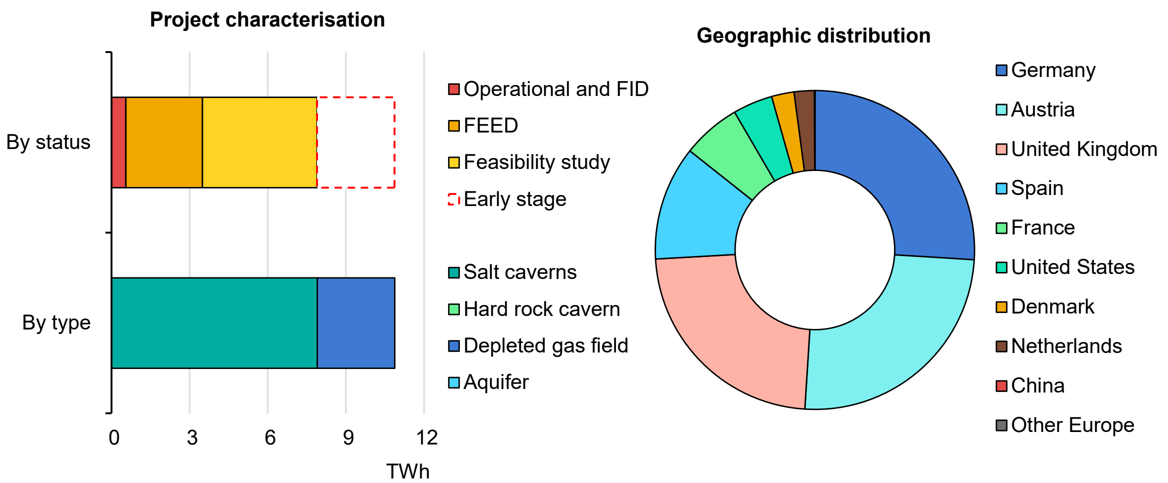
Porous reservoirs, including depleted gas fields and saline aquifers, are more widely available than salt caverns and offer larger storage capacities at lower investment cost, but their suitability for pure hydrogen storage at commercial scale has not yet been demonstrated. In Austria, the Underground Sun Storage 2030 project completed the world's first field test of 100% hydrogen storage in a depleted porous sandstone reservoir, storing 3.3 GWh/100 t H_2 with a 98% purity recovery. Launched in 2024, the EUH2STARS project aims to validate large-scale hydrogen storage in depleted gas fields by the end of the decade, with several storage cycles planned in Austria, Hungary, the Netherlands and Spain.

[49] In addition to underground hydrogen storage, flexibility may also come from compressed hydrogen storage via pipeline linepack, though its full potential remains uncertain; by comparison, natural gas linepack can provide up to 50% of within-day flexibility during peak periods.

Few commercial-scale projects have reached FID

If all announced underground hydrogen storage projects, including new facilities and repurposed natural gas storage sites, are realised by 2035,[50] around 11 TWh of storage capacity (equivalent to 325 kt H_2) would be available. However, of this volume, only 5% has reached FID or is under construction, equivalent to around 2.5% of the annual production of committed low-emissions hydrogen projects (either operational or with FID). If all announced projects are fully realised, global underground hydrogen storage capacity by 2035 would be equivalent to 0.2% of today's global underground natural gas storage capacity, and around 1.5% of current natural gas storage capacity in salt caverns and domes.

Figure 4.5 Global underground geological storage capacity for hydrogen based on announced projects by technology, status and region, 2035



Notes: FEED = front end engineering design; FID = final investment decision. "Salt caverns" covers both underground storage in salt caverns and salt domes. More details of the announced projects for underground hydrogen storage can be found in the new Hydrogen Tracker on the IEA website.
Source: IEA Hydrogen Infrastructure Projects Database (September 2025).

Up to 11 TWh/0.3 Mt H_2 of underground hydrogen storage could be available by 2035, but only 5% has reached FID, with most projects in Germany, Austria and the United Kingdom.

Progress on underground hydrogen storage has been mostly limited to demonstration-scale projects in salt caverns, primarily in Germany, with only one commercial-scale project having reached FID and a few others nearing FID during the past year. Despite other countries assessing underground hydrogen storage, particularly in Europe, projects have not yet advanced to implementation. Developers cite challenges such as the need to transpose EU rules on regulated

[50] The development timeline for underground hydrogen storage is estimated at 6-11 years, including around 2.5 years before FID, with repurposing projects expected to fall towards the lower end of this range. Given the long lead times, projects aiming for commissioning by 2035 should already be at least at the concept or planning stage.

access to infrastructure and to create viable business models, particularly in the early stages when public support may be needed to get projects off the ground. The most notable milestones of the past year include:[51]

- **RWE (Germany).** Took FID for the Epe-H2 project (115 GWh/3.4 kt H_2), Germany's first commercial hydrogen salt cavern storage facility, now under construction with 70% federal and 30% state funding and commercial operation targeted for 2027.
- **EWE (Germany).** Completed the HyCAVmobil pilot in a salt cavern in Rüdersdorf (0.2 GWh/6 t H_2) in December 2024. Under the Clean Hydrogen Coastline project, EWE is preparing conversion of underground natural gas storage caverns at Wesermarsch, commissioning Neuman & Esser in March 2025 to supply compressors for a repurposed salt cavern (60 GWh/1.8 kt H_2), with first operations targeted for 2027.
- **Storag Etzel (Germany).** Started hydrogen filling of the H2Cast demonstration in May 2025 (3 GWh/90 t H_2), with operations expected by end-2026. In February 2025, the company secured a contract with EnBW to develop new salt cavern hydrogen storage at Etzel with a geometric volume of around 0.8 million m³ (~200 GWh/6 kt H_2), targeting 2027 operations.
- **VNG (Germany).** Secured EUR 60 million public funding through IPCEI for the Go! Speicher project at Bad Lauchstädt (August 2024) to convert an existing natural gas storage salt cavern for hydrogen storage (~140 GWh/4.1 kt H_2).
- **Uniper (Germany).** Commissioned the Hydrogen Pilot Cavern project at a salt cavern in Krummhörn in August 2024 (1.8 GWh/54 t H_2), with testing ongoing, supported by EUR 2.4 million of regional public funding.
- **Enagás (Spain).** Signed an agreement with Solvay in June 2025 to repurpose Solvay's salt caverns originally developed for sodium carbonate production for hydrogen storage.
- **UK Oil & Gas.** Announced completion of pre-FEED design in January 2025 by DEEP.KBB for an underground hydrogen storage salt cavern facility in Weymouth-Dorset (24 caverns, 30.2 TWh/900 kt H_2), with the first cavern planned by 2032.
- **Pingmei Shenma (China).** Began construction in November 2024 of a salt cavern in Henan (~4.5 GWh/135 t H_2), with operations planned for late 2025.

Only a limited number of public consultations on underground hydrogen storage have been launched in the past year. Additional information on infrastructure needs may emerge in the coming months, following the launch of the Hydrogen Mechanism under the EU Energy and Raw Materials Platform in July 2025, as part of the European Hydrogen Bank. The first round of demand and supply matching

[51] A comprehensive list of project announcements related to the construction of new underground hydrogen storage facilities or the repurposing of existing natural gas storage facilities for hydrogen can be found in the IEA Hydrogen Infrastructure Database (September 2025).

is planned for September 2025. The Mechanism may help to identify potential storage and transport infrastructure requirements (see Chapter 6 Policies).

Table 4.5 Market surveys for selected underground hydrogen storage projects, Q3 2024 – Q2 2025

Project	Country	Organiser	Description
French section of the hydrogen backbone Salt caverns	France	Storengy	Non-binding call for interest received 26 responses - interest in fast-cycling storage for daily use rather than seasonal storage. Storage demand estimated at up to 2.8 TWh/85 kt H_2 by 2035.
Gronau-Epe Salt cavern (repurposed)	Germany	RWE Gas Storage	Has already sold 70% of its capacity; Binding tender for 30% of unbooked storage capacity available from 2028.

Infrastructure at ports

Ports are critical nodes in the global energy supply chain. In 2024, more than 40% of crude oil, 13% of natural gas (as liquefied natural gas [LNG]), nearly 40% of LPG and 18% of coal were globally traded, mainly by ship In 2023, the value of trade in fossil fuels was equivalent to USD 2.6 trillion, and accounted for about 15% of global seaborne trade in economic terms. However, in tonnage terms, this share is larger, representing roughly 40% of all cargo.

Energy trade by ship is central to the global economy, and its smooth operation is a cornerstone of energy security. Maritime transport allows for diversified supply routes, reducing reliance on fixed infrastructure such as pipelines, and enabling countries to tap into a wider range of suppliers. In addition, ports typically host substantial storage capacity, allowing countries to buffer short-term fluctuations in supply and demand. For example, Japan can store the equivalent of around 10% of its annual gas consumption in its LNG storage tanks at regasification terminals, and Spain around 8%[52]. Port-based facilities function as strategic assets for managing energy stocks, responding to crises and supporting market stability.

Trade in chemical feedstocks, while smaller in volume, is closely linked to energy trade. Ammonia and methanol have long-established global markets as chemical feedstocks. Before LNG trade became widespread, both were used as means to

[52] These shares may vary over time, as natural gas demand fluctuates, but are provided here to give a sense of the order of magnitude.

export natural gas from resource-rich regions,[53] with ammonia shipped as a liquefied gas at -33°C and methanol as a liquid at ambient conditions. Today, global anhydrous ammonia[54] trade amounts to around 20 Mtpa (equivalent to ~3.5 Mtpa H_2), representing around 10% of global production. This is transported on liquefied gas tankers primarily serving the larger LPG market, as both products share similar handling requirements and boiling points, though ammonia[55] trade remains smaller-scale. In addition, a significant share of ammonia-derived trade occurs in the form of solid fertilisers such as urea, which accounts for around 60% of global ammonia consumption; urea trade represents the equivalent of about 16% of total ammonia production. Global methanol trade stands at around 30 Mtpa (equivalent to ~6 Mtpa H_2), mainly supplying the chemical sector. Looking ahead, both ammonia and methanol may increasingly serve dual roles as chemical feedstocks and low-emissions fuels, potentially expanding traded volumes and reshaping logistics chains and port infrastructure requirements.

Ports could play an important role in developing a more competitive liquid market for low-emissions hydrogen, hydrogen-based fuels and derivatives, providing advantages including:

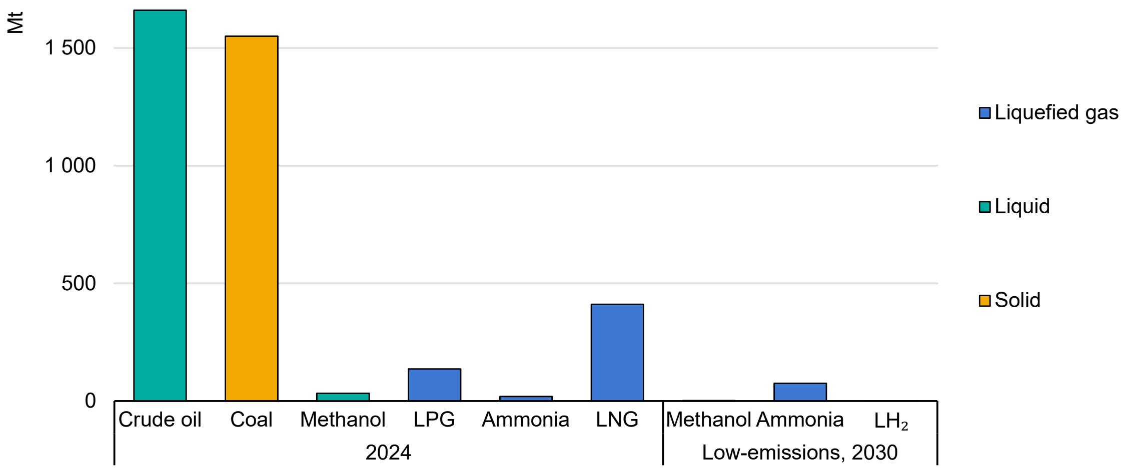
- Cost advantage: Providing access to lower-cost hydrogen and its derivatives produced in more favourable locations, even if distant.
- Supplier diversity and flexibility: Enabling diversified import routes that can be adapted over time, reducing reliance on specific suppliers or countries and improving resilience to geopolitical risks, unlike fixed pipelines.
- Storage and system resilience: Offering above-ground storage at import terminals to buffer market or logistical disruptions and provide back-up supply.

Although trade in low-emissions hydrogen is expected to remain relatively small by 2030, even in the very unlikely case that all announced projects materialise (see section on Trade), a notable expansion of port infrastructure may still be required. If all announced projects realise, most traded volumes would be in the form of ammonia, which would imply handling volumes equivalent to almost 50% of today's combined LPG and ammonia trade (Figure 4.6). Given the potential of ammonia and LPG to use similar infrastructure (albeit subject to different safety regulations) low-emissions hydrogen trade could drive significant investment in LPG/ammonia infrastructure, even at modest trade volumes. Over the longer term, if climate pledges are met and fossil fuel trade declines, growing trade in low-emissions hydrogen-based fuels could reshape port infrastructure currently

[53] Several natural gas–rich countries used to convert natural gas into ammonia and methanol as a means to monetise their resources. This approach offered a practical export route at a time when LNG infrastructure was limited. In Trinidad and Tobago, for example, industrial-scale ammonia production began in 1959 and expanded significantly through the 1970s and 1980s, making the country a major global exporter of both ammonia and methanol.
[54] Anhydrous ammonia is a pure form of ammonia containing over 99% ammonia and no water.
[55] Hereafter, the term "ammonia" refers to anhydrous ammonia.

centred on fossil energy products. Accommodating this shift may require significant port redesigns to ensure appropriate safety zones for storing and handling hydrogen-based fuels, particularly where space is constrained.

Figure 4.6 Seaborne trade of key energy products in 2024 and for low-emissions hydrogen based on announced projects in 2030



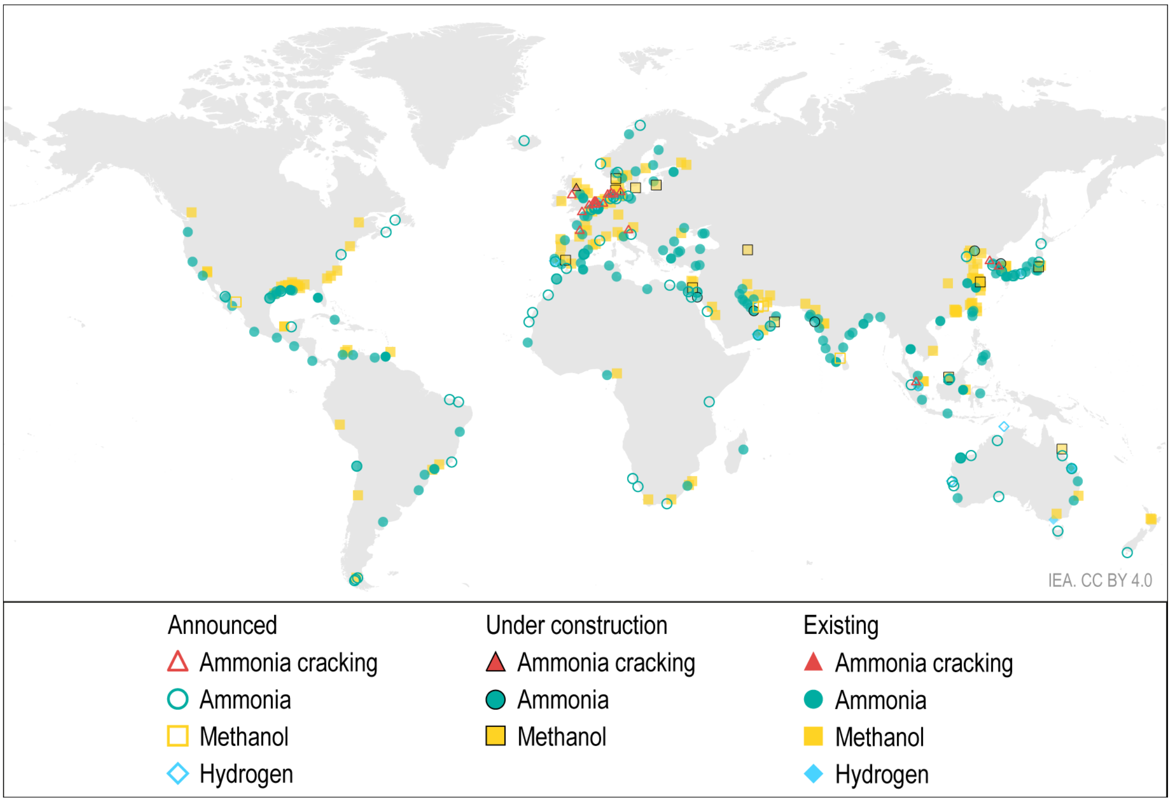
Notes: LPG = liquefied petroleum gas; LNG = liquefied natural gas; LH_2 = liquid hydrogen.
Source: IEA Hydrogen Production Projects Database (September 2025).

Trade in low-emissions hydrogen remains limited in 2030 compared to global fuel trade, but announced projects would be equivalent to nearly 50% of current LPG and ammonia trade.

Trade announcements for low-emissions hydrogen show diversified export infrastructure and expanding import capacity

Based on announced projects, around 120 new hydrogen-based fuel terminals and port infrastructure developments are planned by the end of the decade. While the focus of the announcements is on ammonia handling, a larger number of methanol facilities are already under construction, mainly to support maritime bunkering. The announcements suggest a more diversified supply base across exporting ports compared to importing countries. In addition to earlier announcements in Australia, Brazil, Egypt, Namibia and Mauritania, further progress over the past year includes potential ammonia export infrastructure developments, such as the AM Green–Port of Rotterdam agreement for Indian exports, the Chbika project in Morocco, new projects in the Aqaba Special Economic Zone in Jordan, and more than USD 2 billion in engineering, procurement and construction (EPC) contracts awarded for the Ta’ziz chemicals hub port infrastructure in Ruwais, United Arab Emirates.

Figure 4.7 Existing and announced port infrastructure projects for hydrogen and hydrogen-based fuels trade and bunkering



Source: IEA Hydrogen Infrastructure Projects Database (September 2025).

Ports already handle ammonia in almost 60 countries and methanol in mor than 40, new facilities are planned in over 30 countries for ammonia and about 20 for methanol.

Today, almost 60 countries have port terminals for handling ammonia and more than 40 for methanol. Traditionally, this infrastructure was concentrated on the export side in a few gas-rich countries for supply to a wider range of importers. In contrast, low-emissions hydrogen trade shows the reverse pattern: more than 20 countries are planning new port infrastructure for ammonia exports, while import plans are concentrated in a significantly smaller number of countries, with new infrastructure planned in a few countries in Europe, and Japan and Korea.

In Europe, Yara opened a new 3 Mtpa ammonia import terminal in Brunsbüttel, Germany, in October 2024. OCI is tripling capacity at its Rotterdam terminal to 1.2 Mtpa by expanding its loading and unloading infrastructure, without adding new storage tanks, though progress has been delayed, partly due to updates to the Dutch ammonia storage and handling code. Other projects, such as Mabanaft's planned terminal in Hamburg, Germany, have been postponed to 2028, with the reason given being the absence of a clear EU regulatory framework, among other factors.

In Korea, Samsung is building the ammonia import terminal that will serve the project awarded in the first CHPS tender (Table 4.1). With regards to policy developments, in Japan, the government launched a USD 39 million subsidy tender in March 2025 to cover 50% of FEED costs for hydrogen-related storage infrastructure, including import clusters.

An increase in ammonia trade may lead to the development of ammonia cracking infrastructure where the final demand is for hydrogen rather than ammonia. In September 2024, the largest ammonia cracking pilot plant to date (15 ktpa ammonia) became operational at the port of Antwerp, Belgium (excluding larger legacy facilities such as Arroyito in Argentina). Another ammonia cracker is under construction in Gelsenkirchen-Scholven (Germany) by Uniper and thyssenkrupp Uhde, with a capacity of 28 t/day ammonia (~10 ktpa ammonia). In December 2024, Air Liquide secured a EUR 110 million grant from the European Innovation Fund to develop, among others, a large-scale ammonia cracker at the same port. In Korea, a small facility in the Chungbuk Special Zone became operational in October 2024. In April 2025, KBR was awarded a second ammonia cracking technology contract by Hanwha for power generation in Korea, with a capacity of 214 t/day H_2 (~400 ktpa ammonia), following an earlier contract in 2023. Additional facilities are under assessment in several ports, with recent public consultations on ammonia infrastructure also gauging market interest for ammonia cracking capacity (Table 4.6).

Table 4.6 Market surveys on selected ammonia above-ground storage facilities at ports, Q3 2024 – Q2 2025

Location	Organiser	Description
Port of Rotterdam (Netherlands)	Chane	Non-binding call of interest for a new ammonia import terminal.
Port of Rotterdam (Netherlands); Port of Antwerp (Belgium)	VTTI	Non-binding call of interest for its Amplifhy Rotterdam and Antwerp projects to assess ammonia and cracking infrastructure needs; the project has now moved to negotiation of Heads of Agreements in response to strong demand.
Port of Vlissingen (Netherlands)	LBC	Non-binding call of interest for ammonia and cracking infrastructure.
Port of Antwerp (Belgium)	Vopak	Non-binding call of interest for a new ammonia import terminal.

Most low-emissions hydrogen export projects currently plan to ship hydrogen in the form of ammonia or via pipelines as compressed hydrogen. Trade in liquefied hydrogen remains at a lower level of technological readiness,[56] with no firm

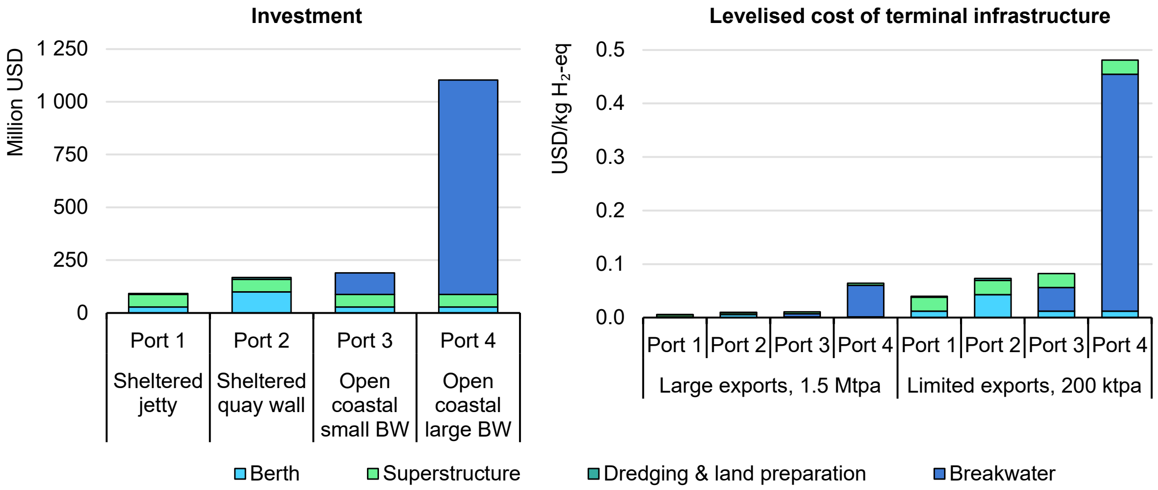
[56] More information on the status of hydrogen liquefaction, storage and liquefied hydrogen tankers is available in the ETP Clean Energy Technology Guide.

investment commitments for large-scale infrastructure as yet. Over the past year, several agreements have been signed to explore potential liquid hydrogen (LH_2) corridors, including Singapore-based Keppel's conditional offtake agreement with Woodside for LH_2 from Australia; a joint development agreement between the Port of Duqm (Oman), the Port of Amsterdam (Netherlands), and the Port of Duisburg (Germany) for an LH_2 corridor; and an agreement between Ecolog and Tata Steel to explore LH_2 trade from Norway to the Port of Amsterdam.

Feasibility of first low-emissions hydrogen exports will depend on access to brownfield port sites or natural shelters

Using existing port sites offers important advantages for low-emissions hydrogen export projects, as brownfield developments can reduce capital costs and accelerate project timelines. Existing ports often provide deep-water access, available processing space and integrated logistics networks that facilitate faster deployment. Nevertheless, almost 60% of planned low-emissions hydrogen projects targeting trade by 2030 are for development in EMDEs (excluding China), where suitable port infrastructure may not always be available. In such cases, particularly in remote areas aiming to harness high-quality renewable resources, greenfield port development or major expansions may be required. However, long lead times and high capital requirements could have a significant impact on the overall feasibility of low-emissions hydrogen export projects.

Figure 4.8 Indicative investment and levelised cost for ammonia export terminal infrastructure by utilisation rate and illustrative port archetype



Notes: BW = Breakwater; Port 1 = Naturally sheltered jetty port; Port 2 = Naturally sheltered quay wall port; Port 3 = Open coastal jetty port with small breakwater; Port 4 = Open coastal jetty port with large breakwater.
Source: IEA analysis based on data from the Port of Rotterdam.

Port costs are low for sheltered, highly utilised terminals, but a need for costly breakwaters and low utilisation rates can undermine the case for low-emissions ammonia exports.

The location of new ports will be influenced not only by land availability, but also by geographic and environmental conditions. Water depth is critical to accommodate large vessels used for transporting energy products, particularly liquefied gases, though liquefied hydrogen may require less draft (depth) due to its lower density. Weather conditions such as wind, waves and currents also play a key role in determining the operational reliability of port infrastructure. Access to natural or artificial shelter reduces downtime by limiting periods when loading and unloading cannot be conducted safely. Excessive downtime can undermine the economic viability of a port and means that larger storage capacity is needed to maintain operational continuity, which can substantially increase costs, particularly for liquefied gas storage. Mitigation options include relocating berths, selecting alternative sites, or building breakwaters to reduce wave exposure, which can be costly. Port site selection and infrastructure design therefore requires careful consideration of potential trade-offs.

Port terminal costs include several major components, notably for the berth (covering elements such jetties, mooring piles and quay walls[57]), superstructure, dredging, land preparation, and potentially a breakwater. Figure 4.8 illustrates the cost of a jetty capable of receiving vessels up to very large gas carrier size; accommodating larger ships, comparable to today's LNG tankers, would require larger and more costly jetties (although the incremental cost increase is relatively modest). When no breakwater is required, berth costs typically account for around one-third of total terminal costs at jetty ports. At quay-wall ports, berth costs are roughly three times higher and therefore represent a larger share. Superstructure costs are similar in absolute terms across both configurations, but they account for a larger share at jetty ports and a smaller share at quay-wall ports due to their higher berthing costs.

The superstructure – loading arms, manifolds, pipelines and support frames for the safe transfer of hydrogen and its derivatives – varies depending on the carrier. For methanol and liquid organic hydrogen carriers (LOHC), superstructure costs are similar than for oil product terminals, and roughly 20% lower than for ammonia. In contrast, LH_2 would require significantly more complex and costly superstructures due to its very low boiling point (-253°C compared to – 33°C for ammonia and -162°C for LNG), requiring advanced cryogenic piping and loading systems. Breakwater construction can add substantial cost, ranging from EUR 100 million to EUR 1 billion depending on site-specific factors, particularly water depth, and may translate into a levelised cost of up to EUR 0.5/kg H_2-eq at low utilisation rates, for example when production volumes are still limited. While breakwaters improve operational reliability by reducing downtime, their high cost may offset potential advantages from siting terminals in locations with excellent

[57] A jetty is a structure projecting into the water to allow vessels to berth offshore, while a quay wall is constructed parallel to the shoreline, providing linear space for multiple berths directly along the coast.

renewable energy resources, particularly wind. Several approaches can help reduce the capital burden of port infrastructure for low-emissions hydrogen, primarily by maximising asset utilisation:

- **Hydrogen hubs: clustering production.** Concentrating multiple producers near the port increases throughput, improves utilisation rates and strengthens the business case for shared storage and export infrastructure. These hubs often develop within free zones or special economic zones, which may offer regulatory flexibility, tax incentives and integrated logistics. Several announced projects are in Jordan's Aqaba Free Zone, Egypt's Ain Sokhna within the Suez Canal Economic Zone, and Oman's Port of Duqm in the Duqm Special Economic Zone. By centralising production, storage and export facilities, these hubs could reduce costs and enable more efficient infrastructure development. Demand is already relatively concentrated (see Chapter 2 Hydrogen demand) with low-emissions hydrogen expected to arrive at key distribution points for further inland delivery.
- **Multi-molecule terminals: flexible handling.** Designing terminals to accommodate multiple molecules (e.g. ammonia, methanol, LNG or CO_2) allows operators to share infrastructure across carriers, lowering unit handling costs. In such cases, quay walls, though more expensive than jetties, offer greater flexibility by providing extensive berthing space that can be divided to handle different molecules with distinct loading systems and allow for simultaneous operations. In contrast, jetties offer more limited operational flexibility (see next section).
- **Common-user infrastructure: enabling industrial clusters**. Developing dedicated port infrastructure for a single commodity can be costly, but shared facilities serving multiple users and sectors can improve utilisation, reduce costs, and support broader industrial development. In Chile, the Cabo Negro Industrial Park in the Magallanes Strait aims to attract a range of industries, including hydrogen production, with ENAP and EDF signing an agreement to use the site for ammonia exports. In Namibia, expansion of the Port of Walvis Bay is being positioned as a platform for industrialisation and manufacturing, and there are plans for a EUR 250 million hydrogen and ammonia export terminal built by the Port of Antwerp-Bruges.
- **Offshore terminals: phasing investments**. Floating terminals can offer a cost-effective and flexible alternative to fixed infrastructure, requiring lower upfront capital and allowing for leasing structures, thus shifting part of the investment to operating costs and providing financial flexibility. Terminals are relocatable, enabling adaptation to changing market conditions, and can serve as interim solutions during phased port development when cargo volumes remain limited or uncertain. However, they require favourable weather and sea conditions with generally sheltered locations. Several concepts for ammonia floating storage and regasification units (FSRUs) are advancing, although the technology has still to be demonstrated. In recent years, ClassNK has issued

Approvals in Principle for designs developed by MOL and Mitsubishi Shipbuilding, as well as NYK Line, Nihon Shipyard and IHI. In addition, Single Point Mooring Terminals are also being considered.

Multi-molecule terminals could make infrastructure fit for more users

As the energy transition advances, ports are set to play an even more vital role, serving as gateways for fossil fuels and low-emissions fuels and feedstocks, as well as logistical anchors for CO_2 transport and storage infrastructure. However, planning this infrastructure in isolation for each "molecule" may be less efficient and more costly. With legacy fossil fuel infrastructure and emerging low-emissions carriers likely to coexist for some time, developing multi-molecule terminals could present a strategic opportunity to optimise existing assets, reduce redundancy and mitigate the risk of future stranded fossil infrastructure. Key advantages of such an approach include:

- **Phased transition and operational flexibility**. Existing terminals can be incrementally adapted to enable the coexistence of fossil and low-emissions fuels, providing operational flexibility amid evolving market demand. These multi-molecule terminals have the potential to become integrated energy hubs, supporting the trade and storage of alternative fuels and facilitating the early deployment of low-emissions bunkering hubs. They can also provide services that offer system flexibility, such as virtual liquefaction.
- **Economies of scope: reduced infrastructure needs and enhanced cost efficiency**. Co-locating multiple molecules within existing port terminals, whenever possible, reduces the need for new infrastructure. Even when different molecules are handled in adjacent rather than integrated terminals, the shared use of assets like deep-water berths, grid connections and road access can reduce costs and accelerate construction timelines compared to building separate infrastructure for each molecule. However, safeguards must be in place to prevent co-mingling and ensure quality control, particularly where low-emissions fuels share infrastructure with conventional fuels, including robust traceability and verification systems such as fuel fingerprinting and well-to-wake carbon intensity monitoring.
- **Land use and social licence to operate**. Consolidation within existing terminals can reduce land requirements and can benefit from existing zoning regulations and community relations. However, introducing new or hazardous (e.g. toxic or cryogenic) substances may still raise challenges for regulatory and social acceptance.
- **Cryogenic process integration**. Using the cold energy released during LNG evaporation to liquefy CO_2 reduces energy demand and costs, while improving the efficiency of the overall LNG regasification–CO_2 liquefaction process. If hydrogen is eventually traded as liquefied hydrogen, the energy released during evaporation at the receiving terminal could be used to meet other cooling demands.

Table 4.7 Adapting terminals: pathways for multi-molecule ports

Adaptation type	Molecule and source	Infrastructure needs
Established molecule trade, new source	Biomethane Synthetic methane	Can use current LNG infrastructure, as their physical properties are similar to those of fossil-based natural gas.
	Biofuels Synthetic liquid fuels	Drop-in fuels such as SAF (similar to kerosene) could use existing infrastructure for refined oil products. *
Established molecule trade, new scale and source	Low-emissions ammonia	If global trade in ammonia grows, existing and new ammonia terminals should be scaled up. In some cases, LPG terminals could be repurposed to handle ammonia, provided safety and technical requirements are met.
	Low-emissions methanol	An increase in methanol trade would require scaling up dedicated chemical tanker fleets and supporting infrastructure to accommodate higher volumes.
	LOHCs	LOHC could utilise existing chemical and oil product logistic chains, handled similarly to other bulk chemicals.
New molecule trade, new infrastructure needs	Liquefied H_2	Highly insulated cryogenic storage tanks and transfer systems that can handle temperatures of - 253°C.
	Liquefied CO_2	Pressurised, refrigerated storage tanks and dedicated transfer equipment to manage CO_2 at -35°C to -15°C and 12–25 bar.

* Most ports today handle both crude oil and refined products (like gasoline, diesel, and jet fuel), though crude oil volumes are larger. Synthetic fuels would typically be managed like other refined products.

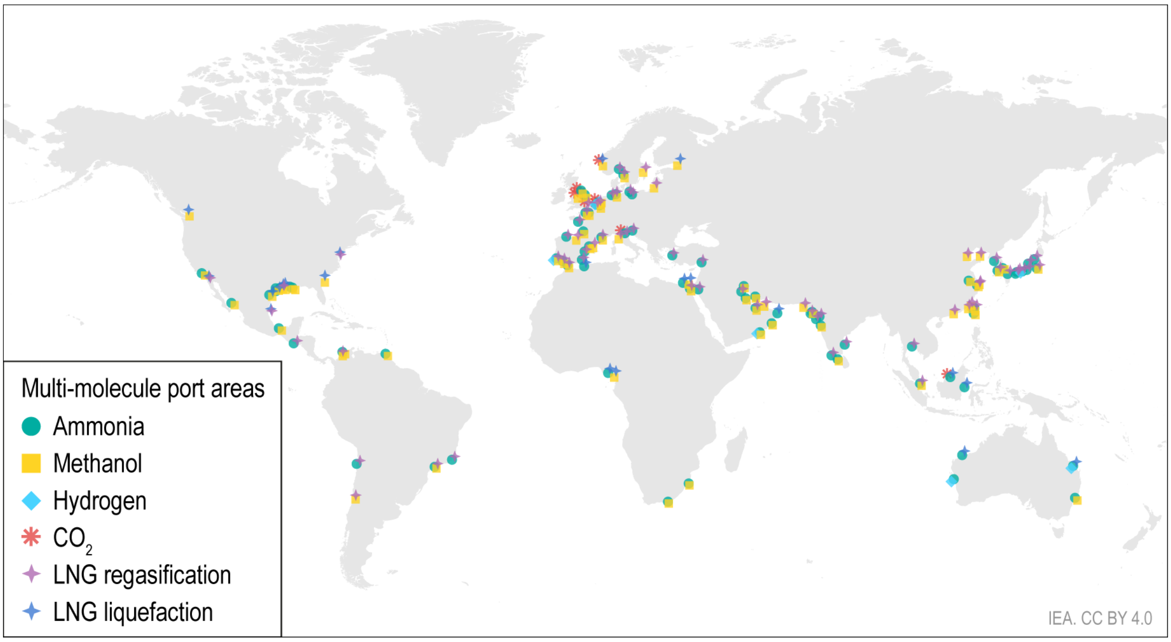
Several projects are exploring the development of multi-molecule port terminals that could handle hydrogen, ammonia and other low-emission fuels, and CO_2 (Table 4.8). Most remain at early conceptual stages, with limited information available on technical feasibility, economic viability, and integration with existing infrastructure More than 110 ports associated with announced low-emissions hydrogen and CCUS projects present opportunities for multi-molecule handling, particularly in Europe, the Asia-Pacific region and the Middle East (Figure 4.9), with synergies most frequently identified between adjacent ammonia, methanol and LNG regasification terminals.

Table 4.8 Projects exploring the potential of multi-molecule port terminals

Project	Location	Existing infrastructure	Potential adaptation of infrastructure
Medhyterra	Fos Tonkin terminal, France	LNG regasification	Partial redevelopment of the LNG terminal into a low-emissions ammonia import facility, combining use of existing infrastructure with new dedicated assets for ammonia.
Musel E-Hub	Port of Gijón, Spain	LNG regasification	Enagás, one of the owners of the LNG regasification plant and the University of Oviedo signed an agreement to conduct a techno-economic study on adapting the LNG terminal into a multi-molecule facility.
Madoqua Project	Port of Sines, Portugal	New	Considering the construction of an ammonia, methanol, liquid CO_2 and SAF hub.
Namikata terminal	Imabari, Japan	LPG import	Seven companies plan to repurpose a 1 Mtpa LPG and petroleum products site into an ammonia import hub by 2030, including conversion of 45 kt LPG refrigerated tanks for ammonia storage.
IHI conversion	Various ports, Japan	LNG regasification	IHI studying LNG terminal conversion for ammonia, with modifications planned post-2025 for co-firing in turbines.
Zeebrugge Multi-molecule Hub	Port of Zeebrugge, Belgium	LNG regasification	Assessing potential for reconfiguration into a multi-molecule hub for importing H_2, ammonia, biomethane and synthetic methane, and exporting CO_2, with a call for interest in 2024 to assess market demand.
Wilhelmshaven green hydrogen hub	Port of Wilhelmshaven, Germany	LPG import	Plans for building a new ammonia cracker and reusing existing oil pipelines for hydrogen transport.
Mid West Clean Energy Project	Western Australia	New	Planning a jetty-less offshore facility designed for ammonia exports and CO_2 handling en route to storage.
ApolloCO_2 Project	Port of Revythoussa, Greece	LNG regasification	Use of residual cold energy from LNG regasification at the Revythoussa terminal to liquefy captured CO_2 to transport it to its storage site.
H_2 & CO_2 terminal in Afrikahaven	Port of Amsterdam, Netherlands	New	ECOLOG is developing a new combined LH_2 and CO_2 terminal, where the cold energy from the LH_2 regasification would be used to liquefy CO_2.

Hybrid operations at port terminals can create important synergies by allowing infrastructure to accommodate multiple energy carriers and molecules. However, strict application of unbundling rules designed for single-carrier systems may limit operators' ability to capture these synergies. Maintaining reasonable unbundling frameworks that ensure non-discriminatory access and transparency,[58] while allowing integrated operators to co-manage multiple services within one facility, can help support innovation, reduce duplication of assets, and improve the business case for terminal investments. Flexibility in regulatory design will be important to ensure that competition concerns are addressed without hindering efficient infrastructure development.

Figure 4.9 Identified synergies between existing and announced port infrastructure projects that could enable multi-molecule terminals



Notes: Only operational and under construction regasification and liquefaction projects have been considered. For ammonia, methanol and CO_2 terminals, those in operation, under construction, or in an advanced stage for FID decision have been included. Terminals located within 50 km of at least one other terminal handling a different carrier are included, as a proxy for potential multi-molecule integration opportunities, irrespective of whether facilities belong to the same or to nearby ports.
Sources: IEA Hydrogen Infrastructure Projects Database (September 2025) and IEA CCUS Projects Database (2025).

In more than 110 port areas, synergies between existing and announced projects could create potential to handle multiple molecules within the same terminal or port.

[58] The European Commission's Hydrogen and Gas Decarbonisation Package, adopted in May 2024, proposes updated unbundling provisions for hydrogen network operators, aiming to ensure non-discriminatory access and transparency while allowing integrated operators to manage multiple services within one facility.

Existing port infrastructure may be a springboard for enabling fuel bunkering of low-emissions hydrogen-based fuels

Maritime fuel bunkering[59] accounts for around 2.5% of total global final energy demand, but more than 6% of global annual oil use. Shipping is widely regarded as a sector in which emissions are hard to abate, due to the limited availability of low-emissions fuel alternatives (see Chapter 2 Hydrogen demand). Hydrogen-based low-emissions fuels, such as ammonia, methanol and hydrogen, could play an increasingly important role in decarbonising shipping; however, their use would require adaptations to both ships and bunkering infrastructure.

The adoption of these fuels in shipping depends on three linked developments: (1) strong demand signals through global GHG regulations, such as the forthcoming International Maritime Organization (IMO) Net-Zero Framework expected in October 2025 (see Chapter 2 Hydrogen demand); (2) the commercial deployment of compatible propulsion technologies (see Chapter 5 Investment and innovation); (3) and the scaling-up of fuel supply alongside the infrastructure needed to safely store, handle and bunker these fuels. Ports will play a critical role as anchorage points in the global low-emissions fuel supply chain, and their readiness will be essential for the uptake of low-emissions hydrogen-based fuels in maritime transport.

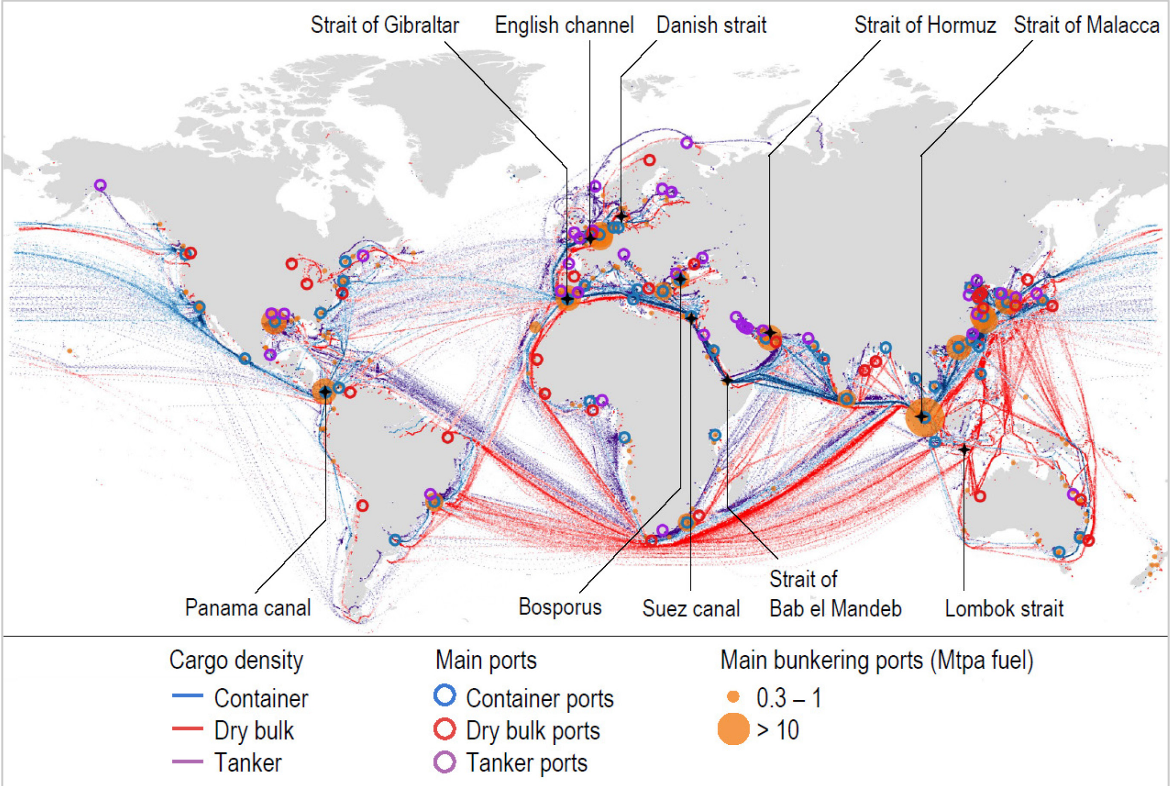
Marine fuel consumption is highly concentrated in a small number of major ports. Singapore alone supplies around one-fifth of global demand, with bunker fuel sales reaching a record 54.9 Mt in 2024, a 6% year-on-year increase, partly due to longer Asia–Europe routes via the Cape of Good Hope amid Red Sea disruptions. The top 17 ports together account for more than 60% of marine fuel consumption. This concentration suggests that developing fuel bunkering infrastructure for alternative fuels in just a few key ports could enable the supply of hydrogen-based and other low-emissions fuels to a large share of the global fleet and principal shipping routes.

Bunkering activity is typically concentrated in locations that offer cost and operational advantages (Figure 4.10). These include areas with dense shipping traffic, where economies of scale can be maximised, which are often close to key maritime chokepoints such as the Straits of Malacca, Gibraltar, Hormuz and the Panama Canal. High-traffic ports like Rotterdam and Singapore further reduce costs by enabling fuel bunkering during cargo operations (loading and unloading), minimising idle time. Intermediate ports along major trade routes, such as Las Palmas (Canary Islands) and Durban (Cape of Good Hope), also enable refuelling without significant detours, saving both time and fuel. Ports near large refineries, such as Fujairah, Houston and Rotterdam, benefit from shorter supply chains and

[59] Throughout this section, “bunkering” refers exclusively to the supply and storage of fuel for ships, and not to general commodity storage.

lower logistics costs. Fiscal incentives, including tax advantages or duty exemptions, further reduce costs, such as in the petroleum free zones[60] around the Panama Canal. Together, these factors encourage vessels to bunker where it is cheapest, fastest and most convenient. Similar considerations are expected to shape the development of alternative fuel bunkering, with a key question being whether today's major hubs will retain their logistical, infrastructural and economic advantages over potential emerging low-emissions fuels hubs.

Figure 4.10 Major shipping routes, key ports by cargo type and main marine fuel bunkering ports, 2022



Note: The map displays 114 high-traffic ports worldwide, categorised by main activity as container, dry bulk or tanker. Some of these ports also serve as major bunkering ports.
Source: Adapted from IEA (2024), Energy Technology Perspectives.

Major bunkering ports are located near high-traffic maritime routes, as well as refineries, minimising detours and reducing costs through economies of scale.

The viability of investing in low-emissions hydrogen-based fuel bunkering will depend on ports' ability to strike the right balance across three dimensions: access to competitively priced low-emissions hydrogen-based fuels (whether produced

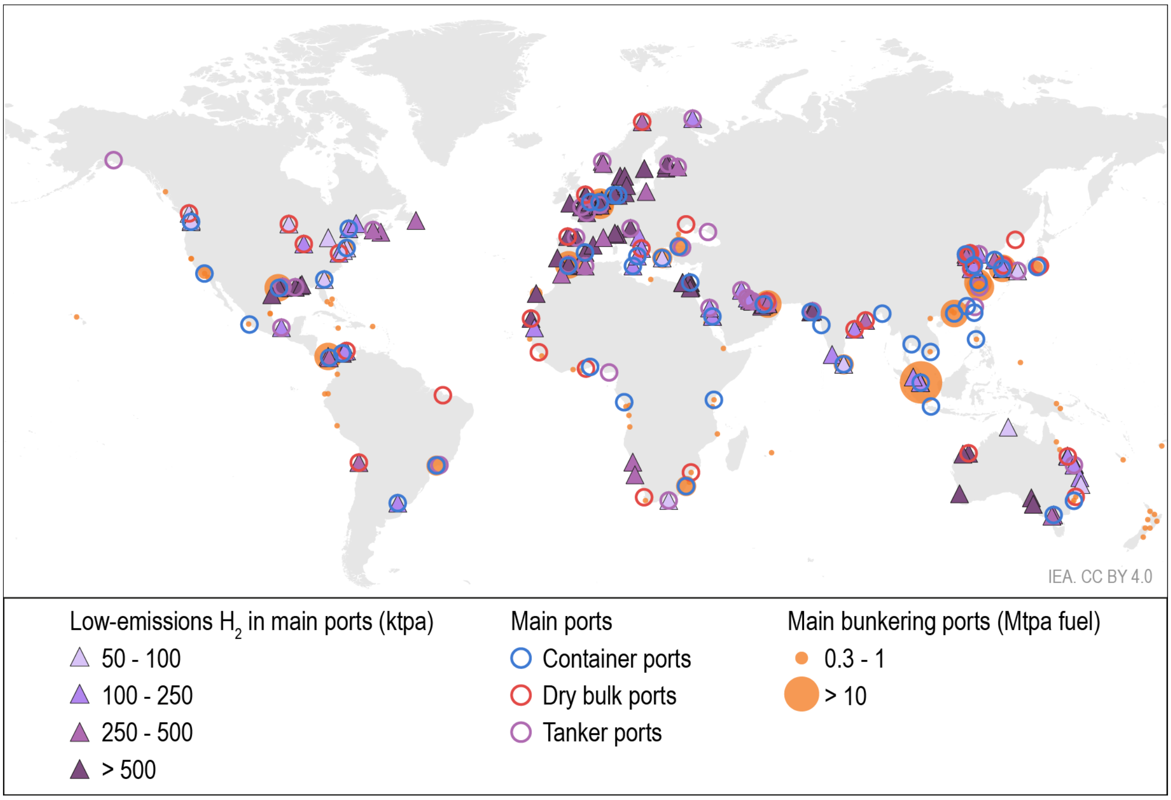
[60] A petroleum free zone is a designated area, typically within or near a major port, where petroleum products can be imported, stored, blended, and re-exported under preferential tax and customs conditions, offering competitive advantages for international bunkering and fuel trade.

nearby or imported), the ability to establish necessary bunkering infrastructure, and favourable shipping economies, including sufficient traffic to justify infrastructure investment, minimal detours, and cargo segments that can more readily absorb higher fuel costs, particularly in the early stages.

Availability of low-emissions hydrogen near major ports

Based on announced low-emissions hydrogen projects expected by 2030, more than 130 of today's main ports (including the principal cargo and marine bunkering ports shown in Figure 4.10) could have capacity for more than 100 ktpa of hydrogen production located within a 500 km radius, and almost 150 ports could access at least 50 ktpa. This indicates that a substantial volume of low-emissions hydrogen may be available near existing global ports, though the scale and distribution of supply vary considerably across regions.

Figure 4.11 Low-emissions hydrogen-based fuels produced close to ports by 2030 based on announced projects, and main ports today



Notes: This figure represents the potential low-emissions hydrogen supply within a 500 km radius of each port if all announced projects targeting operation by 2030 materialise, regardless of announced end-use. Potential overlaps between nearby ports are not accounted for, so figures represent non-additive, indicative supply per port rather than exclusive or realised volumes. Only those ports whose supply of low-emissions hydrogen would exceed 50 ktpa are illustrated.
Source: IEA Hydrogen Production Projects Database (September 2025).

By 2030, over 130 major ports could have access to 100 ktpa of hydrogen, with almost 70% of production located within 500 km of a major port.

For example, Singapore, the world's largest bunkering hub, with nearly 55 Mt of marine fuel supplied in 2024, has only around 130 ktpa of low-emissions hydrogen expected within a 500 km radius, equivalent to less than 700 ktpa of methanol, or just 1.2% of its current bunkering volume in mass terms. This suggests that large-scale imports at competitive prices would be required to support hydrogen-based fuel bunkering. In contrast, Rotterdam, the second-largest bunkering port, with around 10 Mt supplied in 2024, is located near 3.8 Mtpa of announced low-emissions hydrogen production, equivalent to 20 Mtpa of methanol. While this volume is subject to competing demand, it could offer a favourable starting point to support low-emissions hydrogen-based fuels bunkering.

Hydrogen supply prospects vary widely across major ports and cannot easily be generalised by cargo segment, given that they heavily depend on specific geographic and locational factors. Even so, a larger share of main tanker and dry bulk ports are located near significant volumes of announced low-emissions hydrogen projects than container ports. In China, for example, most announced hydrogen projects are located inland of major container ports, with limited availability near coastal hubs. However, China is advancing the development of long-distance hydrogen pipelines from provinces such as Hebei and Shanxi, which could enable major southern coastal cities to access low-emissions hydrogen at competitive prices. Elsewhere, several dry bulk export ports, including Nouadhibou (Mauritania) and Mejillones (Chile), are located near substantial volumes of announced hydrogen production (exceeding 0.8 Mtpa and 0.4 Mtpa by 2030, respectively). Key tanker export ports in the Middle East and in Texas and Louisiana (United States) have large volumes of low-emissions hydrogen from announced projects in proximity, whereas import-oriented ports in the Asia-Pacific region have comparatively little local supply. In Europe, the port of Algeciras (Spain) has over 0.8 Mtpa of production from announced low-emissions hydrogen projects within a 500 km radius, and the ports of Antwerp (Belgium) and Le Havre (France) each have more than 2 Mtpa of production from hydrogen projects within the same radius.

Hydrogen availability alone may not ensure fuel supply, as methanol also requires a sustainable carbon source, which is often uncertain. While methanol engines are commercially available, ammonia propulsion is not, and poses significant port handling challenges. These factors will shape which fuels and ports can viably support low-emissions bunkering in the near term.

Infrastructure readiness for low-emissions hydrogen fuels at ports

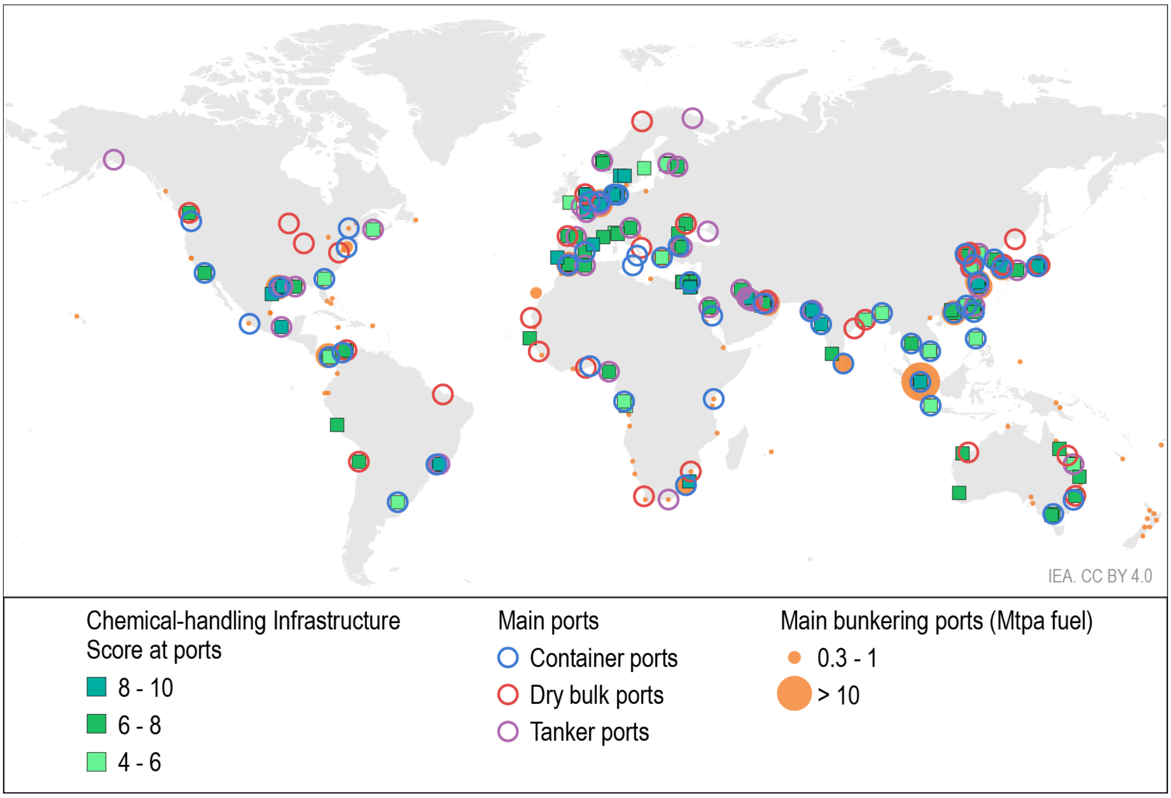
Today's marine fuels are predominantly liquid, with only about 6% comprising LNG and LPG, which are both gaseous at ambient conditions. LPG is generally not bunkered, but is used by LPG carriers that consume part of their cargo as fuel. Transitioning to hydrogen-based fuels would require additional changes to existing port infrastructure and fuel handling systems, requiring investment, land allocation, new construction and permitting.

Ammonia and methanol, while already handled in many ports as chemical cargoes (Figure 4.7), require dedicated fuel bunkering infrastructure when used as marine fuels, due to their specific operational and safety requirements. Methanol, a liquid at ambient conditions, is classified and regulated primarily as a chemical. Ammonia and hydrogen, both gaseous under ambient conditions, require liquefaction or pressurisation for storage and transfer. For hydrogen, cryogenic storage is used, and for ammonia, this is refrigerated, pressurised, or a combination of both, under strict safety and environmental standards. However, ammonia may have a degree of compatibility with existing LPG infrastructure, which is available at more than 1 000 port storage facilities worldwide, offering opportunities for repurposing with appropriate retrofitting for technical and safety considerations. Existing LPG infrastructure – such as tanks, pipelines, loading arms and jetties – could potentially be adapted to accommodate ammonia, though adjustments would be needed to account for its higher density and corrosiveness, which requires more assessment. Examples of this are already underway at the Namikata Terminal and the Tokuyama Complex in Japan.

Ports with established experience in managing chemicals, supported by permitting processes, trained personnel, and existing storage capacity, are likely to be better positioned to enable the early adoption of low-emissions marine fuels, by more rapidly developing bunkering infrastructure. To assess the level of chemical-handling experience that could support future low-emissions hydrogen-based fuel bunkering, the IEA has developed a Chemical-handling Infrastructure Score,[61] inspired by the chemical port index developed by the Maersk Mc-Kinney Møller Center. This score takes into account existing infrastructure for ammonia (NH_3), LPG, methanol (MeOH) and LNG at ports.

[61] The chemical-handling infrastructure score is calculated as: Score = 3 × NH_3 + 3 × LPG + 3 × MeOH + 1 × LNG, where each variable is binary: 1 if the port has storage infrastructure for that carrier (NH_3, LPG, MeOH, or LNG), and 0 otherwise. The infrastructure score can vary from 0, i.e. no storage infrastructure at all, to the maximum score of 10, i.e. storage infrastructure in place for NH_3, LPG, MeOH and LNG.

Figure 4.12 Chemical-handling Infrastructure Score at main ports, 2024



Note: The Chemical-handling Infrastructure Score ranges from 0, i.e. no storage infrastructure at all, to 10, i.e. storage infrastructure in place for ammonia, liquefied petroleum gas (LPG), methanol and liquefied natural gas (LNG).
Source: IEA Hydrogen Infrastructure Projects Database (September 2025).

Nearly 80 ports have a Chemical-handling Infrastructure Score above 5, and 60% of these are also main bunkering ports.

While past trends may not be prescriptive, the rollout of LNG bunkering offers relevant insights. LNG bunkering began in the early 2000s, with the first regular operations in Norway, and has since expanded globally. Initially, ports with existing liquefaction or regasification terminals had a clear advantage due to their established storage and handling infrastructure. However, LNG bunkering has progressively expanded to ports without such facilities. This shows that infrastructure gaps can be overcome over time. In light of this, the Chemical-handling Infrastructure Score incorporates the presence of ammonia, LPG, methanol and LNG storage infrastructure as indicators of a port's potential to support earlier deployment of low-emissions bunkering. While factors such as deep-water access are not explicitly included in the score, they are typically present in ports equipped to receive liquefied gas carriers. One parameter not captured by the score is available land, as limited space may constrain potential to scale up bunkering infrastructure, particularly for ammonia. Over the medium to long term, additional ports could develop the necessary infrastructure despite having a lower score today, as has been seen with LNG bunkering.

According to the Chemical-handling Infrastructure Score, nearly 80 ports worldwide currently score above 5, indicating a degree of experience in managing chemical products and a potentially stronger readiness to handle low-emissions hydrogen-based fuels. Of these, around 60% are already significant bunkering ports. In 55 ports, this infrastructure readiness coincides with the presence of announced low-emissions hydrogen projects for more than 100 ktpa within a 500 km radius – suggesting favourable conditions for early adoption, particularly where spatial constraints on ammonia handling can be addressed. Of these, 35 are also main bunkering ports today. Several such ports are located in the Middle East, Egypt (around the Suez Canal), the US East Coast, and key locations in Europe such as Spain, France, the Netherlands, and Belgium.

Ports with high infrastructure scores but limited local hydrogen supply may need to rely on imports, which could affect cost competitiveness. Conversely, ports near large-scale hydrogen production but with lower infrastructure readiness would need to invest not only in physical assets but also in building the necessary expertise to safely handle these fuels before bunkering operations can begin.

Opportunities for low-emissions fuel bunkering by cargo segment

The other important dimension shaping the potential location of low-emissions hydrogen bunkering hubs is the underlying shipping economics, which are defined both by having sufficient traffic volumes to justify infrastructure investment, and by the type of cargo transported (Figure 4.10). In 2023, dry bulk cargoes[62] accounted for around 55% of global maritime trade by mass (with main dry bulk cargoes accounting for 55% of total dry bulk), followed by tankers.[63] Container ships accounted for 17% by mass, but represented the largest share in value terms, at 65%, due to the higher value per tonne of containerised goods. By value, tanker and dry bulk cargoes each accounted for about 18%, with main dry bulk cargoes contributing roughly 4% of the total value of seaborne trade.

- **Containers**. Due to their high-value cargo, container vessels are generally better positioned to absorb higher fuel costs. Among major container ports, around 55% are located near significant planned low-emissions hydrogen production, but only one third have a Chemical-handling Infrastructure Score above 5. While the overall numbers suggest relatively strong potential for early adoption, several key ports in Eastern China, which are important hubs for containerised exports, have both limited availability of low-emissions hydrogen nearby and low Chemical-handling Infrastructure Scores. Future imports from inland provinces may offer access to hydrogen, but these ports may be better suited to methanol rather than ammonia

[62] Dry bulk goods refer to unpackaged raw materials transported in large volumes. For the purposes of the figures presented, iron ore, grain and coal are classified as main dry bulk cargoes. Other commodities, such as copper, bauxite and phosphate, are also considered dry bulk but are not included in the main dry bulk category of Figure 4.10.
[63] Tankers carry crude oil, petroleum products, natural gas and chemicals.

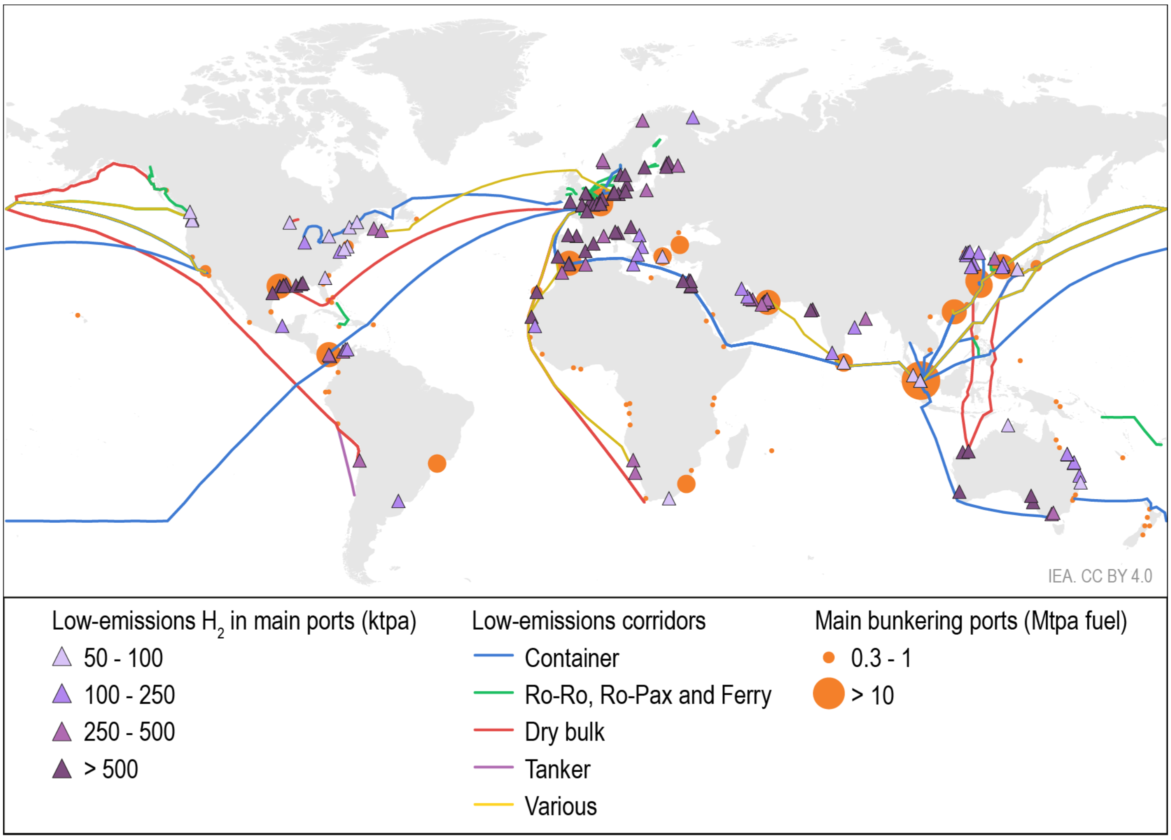
bunkering in the near term. In June 2025, the Port of Hong Kong introduced the Green Maritime Fuel Bunkering Incentive Scheme, offering financial support for initial LNG or low-emissions methanol bunkering operations. However, as most new vessels are being built or retrofitted with dual-fuel engines, refuelling can also take place at alternative ports along major trade routes. This flexibility, combined with the high concentration of container ship traffic on a limited number of key shipping lanes, supports the possibility of developing low-emissions bunkering hubs at selected transit points, such as ports around the Suez Canal, which, despite not being a major bunkering hub today, benefits from both planned hydrogen supply and a degree of infrastructure readiness, with a Chemical-handling Infrastructure Score above 5.

- **Dry bulk**. Among major dry bulk ports, around 70% are located near significant planned hydrogen production, but only 20% have a Chemical-handling Infrastructure Score above 5. This suggests that if low-emissions fuel production projects move forward, new port infrastructure would be needed to enable bunkering or fuel exports, an effort that requires lead time and may be difficult to achieve before 2030. In addition, the low value-to-weight ratio of most dry bulk commodities limits their ability to absorb higher fuel costs, making them less economically viable for early adoption. However, exceptions exist where higher-value bulk cargoes, such as copper, are exported near fuel production sites. Several initiatives are already exploring such opportunities in regions like Latin America and Australia that combine significant dry bulk export volumes with large low-emissions hydrogen production potential. The proposed Chile–Japan/Korea green corridor for copper concentrate is supported by infrastructure at the port of Mejillones, a major hub for copper exports, which already handles chemicals, including ammonia, LPG and sulphuric acid. In Australia, the Pilbara Clean Fuel Bunkering Hub aims to supply low-emissions fuels for iron ore bulk carriers. While Port Hedland – the world's largest iron ore export port and the largest of the four Pilbara ports – does not currently handle chemicals, the nearby Port of Dampier has existing ammonia storage and is included in broader infrastructure planning to support low-emissions fuel bunkering.
- **Tankers**. Around 75% of major tanker ports are located near significant planned hydrogen production, and more than 55% have a Chemical-handling Infrastructure Score above 5. Several ports in the Middle East are particularly well positioned, benefitting from proximity to large-scale low-emissions hydrogen projects, existing chemical-handling infrastructure, and strategic locations along major global shipping routes. For example, the Sohar Port and Freezone in Oman, near the Strait of Hormuz, are planning to offer methanol bunkering.

International co-operation is vital to enable the infrastructure, safety standards and commercial alignment needed to scale up low-emissions bunkering. To foster the uptake and integration of low-emission maritime fuels, low-emissions shipping corridors are emerging as collaborative efforts that connect ports, shipowners, fuel producers, and governments along strategic trade routes. First formalised in the 2021 Clydebank Declaration, which set the ambition to establish at least

6 corridors by the mid-2020s, these initiatives serve as testbeds. They aim to pilot alternative fuels, deploy zero-emission vessels, and develop the handling infrastructure and regulatory frameworks needed. As of 2024, around 60 shipping corridor initiatives had been announced (Figure 4.13), with at least 6 moving towards pre-commercial preparation.

Figure 4.13 Low-emissions shipping corridor initiatives and hydrogen-based fuels produced near high-traffic ports by 2030 based on project announcements



Notes: Ro-Ro = roll-on/roll-off vessel; Ro-Pax = roll-on/roll-off passenger vessel.
Sources: Global Maritime Forum (2025) and IEA Hydrogen Production Projects Database (September 2025).

More than 70% of the announced low-emissions shipping corridors focus on container transport and shipping of wheeled cargo like cars.

About one-third of the initiatives focus on short-haul services, such as ferry networks, while two-thirds target longer-haul or deep-sea routes. In terms of cargo segments, roughly one-third target container shipping, particularly large container vessels; more than 40% focus on vessels designed to carry wheeled cargo, such as cars and trucks (Ro-Ro), or both vehicles and passengers (Ro-Pax)[64]; and 10%

[64] Roll-on/roll-off (Ro-Ro) vessels are designed to carry wheeled cargo, such as cars, trucks and trailers, that can be driven on and off the ship via ramps. Ro-Pax (roll-on/roll-off passenger) vessels combine the cargo capacity of Ro-Ro vessels with passenger accommodation and typically operate on short-sea routes and ferry services.

on dry bulk, with the remainder covering various cargo types. Key fuel choices vary by segment: methanol dominates for containers and ferries; ammonia is prominent for bulk carriers; and battery-electric systems are used for short-sea routes.

Initiatives like Clean Energy Marine Hubs (CEM-Hubs) aim to align public and private efforts across the low-emissions fuel supply chain, enabling ports to become multi-functional energy hubs. Tools such as the Port Readiness Level Toolkit developed with the International Association of Ports and Harbors help assess port capacity beyond infrastructure, including safety, permitting and governance.

Chapter 5. Investment and innovation

Highlights

- Capital spending on low-emissions hydrogen projects reached USD 4.3 billion in 2024, an 80% increase from 2023. Based on recent final investment decisions (FIDs), spending could rise by more than 80% in 2025 to nearly USD 8 billion.
- In 2024, capital spending was almost evenly split between electrolysis and carbon capture, utilisation and storage (CCUS)-equipped hydrogen production. In 2025, electrolysis is expected to account for 80% of spending but only 56% of production from projects under construction, given its higher capital intensity.
- Investment in electrolysis-based projects is highest in China and Europe, while the United States allocates a larger share to CCUS-equipped production. Over 50% of total investment in 2024 and 2025 targets hydrogen use in oil refining and industrial facilities with existing hydrogen demand.
- Guarantees and risk-sharing instruments are essential to scaling up hydrogen projects, particularly for first-of-a-kind deployments and emerging technologies. Collaboration among original equipment manufacturers (OEMs), project developers, public funders and insurers may help reduce perceived risk and strengthen investor confidence.
- Hydrogen venture capital (VC) fundraising fell by one-third in 2024, outpacing declines in broader energy VC. Publicly traded hydrogen companies have also continued to see lower investor returns and revenues over the past year.
- Development finance institutions are increasingly backing blended finance structures, with recent disbursements focused on early-stage costs, including projects in Brazil, Egypt, Morocco, Namibia and South Africa.
- A record number of technologies advanced in technology readiness level (TRL) over the past year, across the hydrogen value chain. First-of-a-kind pilot projects included microwave plasma pyrolysis and synthetic fuel production via Fischer–Tropsch synthesis from solar-converted biogas to syngas, and moving towards larger scale using biogenic CO_2. Infrastructure milestones included validation of hydrogen storage in salt caverns with fast cycling and in depleted gas fields, and an industrial-scale ammonia cracker. On the demand side, there were maiden voyages of ammonia-fuelled vessels using combustion engines or fuel cell propulsion with onboard ammonia cracking, and the first direct reduced iron (DRI) production in rotary kilns using iron ore fines and 100% hydrogen.

Investment in the hydrogen sector

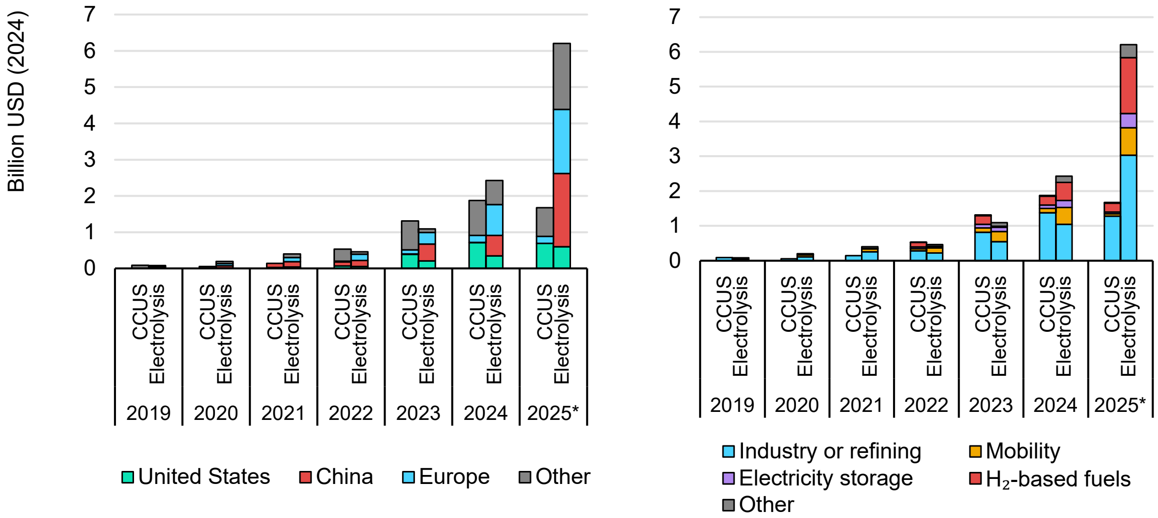
Spending on hydrogen supply projects under construction

Around 90 hydrogen supply projects have taken FID globally since the Global Hydrogen Review 2024 (GHR-24) was published, representing almost 0.9 Mtpa of potential low-emissions hydrogen production. More than 50 projects have completed construction and entered into operation over the same period, while a few projects have been cancelled, despite having reached initial investment commitments. The total number of projects in construction (assuming that all projects that have taken FID are now under construction) has therefore risen to 340 worldwide. We estimate that spending on those projects reached USD 4.3 billion in 2024, 80% more than in 2023. This level of spending is equal to half of the global investment in new liquid biofuel production facilities (USD 8.7 billion in 2024) – to equal investment in new natural gas production in 2024, it would need to be almost 25 times higher. Given that many recent FIDs are relatively large, spending is set to rise more than 80% in 2025 compared to 2024, to reach close to USD 8 billion.

In 2024, 56% of the spending went to electrolysis projects, while 44% went to hydrogen production with CO_2 capture. In 2025, the share of spending going to electrolysis is expected to rise to 79%, as, although it accounts for 56% of the estimated production under construction, it is more capital intensive than CCUS-equipped facilities. Furthermore, electrolysis projects are typically greenfield, while up to 30% of CCUS projects are retrofits, with much of the main and auxiliary equipment already in place. The reduction of investment going to CCUS-equipped facilities is also partly due to the completion of a major project in July 2025, CF Industries's Donaldsonville facility.

Spending on hydrogen supply projects in 2025 is expected to be highest in China and Europe, followed by the United States. Capital spending on electrolysis-based hydrogen production is highest in China and Europe, whereas in the United States, a larger share goes to CCUS-equipped production. By end-use application, the production of hydrogen for oil refineries and industrial facilities with existing hydrogen demand accounts for more than 50% of the total investment in 2024 and 2025. Production for conversion to hydrogen-based fuels, including for export, is expected to represent around 25% of investment in 2025, while road transport applications account for about 10%.

Figure 5.1. Investment in low-emissions hydrogen production installations by region (left) and intended use (right), 2019-2025



Notes: CCUS = carbon capture, utilisation and storage; H_2 = hydrogen. “Other” intended uses include undisclosed end uses. Projects intended for export are classified under the relevant demand category, based on their intended use in the importing country (where known). 2025 values are estimated annualised spending on projects that had reached final investment decision (FID) by mid-2025, and are based on known project costs or capital cost assumptions and announced capacities. Only capital expenditures, including installation, on the hydrogen production facility are included and not any associated equipment for generating or supplying electricity or other fuel inputs, nor for the transport and storage of CO_2, nor for the conversion or end-use of the hydrogen output. The 2025* estimates assume that all projects with an announced FID have entered construction and will proceed according to their scheduled operational date. Delays in construction will lead to lower actual spending in 2025, as was the case for the estimates in GHR-24. Values for investment in new-build hydrogen production projects equipped with CCUS are inclusive of the costs of the base plant, such as the steam methane reformer, and not only the capital costs of CO_2 capture and any dedicated CO_2 transport and storage infrastructure. This is different from the approach taken in GHR-24, which did not include base plant costs. In addition, whenever it was publicly disclosed, specific project investment data was used instead of cost estimates.

Sources: IEA analysis based on data collected through a survey to OEMs, engineering, procurement and construction (EPC) companies and project developers, data from McKinsey & Company and the Hydrogen Council; BloombergNEF, Argus Media Group, All rights reserved, NETL (2022); IEA GHG (2017).

In 2025, investment in electrolysis-based production is set to reach more than triple that of CCUS-equipped production, with most of the spending for existing uses.

The largest hydrogen production project to reach FID since GHR-24 is the Blue Point Complex being developed in Louisiana, United States. This is expected to produce around 250 ktpa of hydrogen from natural gas from 2029, with over 95% of the produced CO_2 captured for geological storage. The hydrogen will be used for the onsite production of ammonia, and the total capital cost, including hydrogen production, ammonia synthesis and ammonia shipping infrastructure, is estimated at USD 4 billion. The project partners (CF Industries, JERA and Mitsui) intend to claim US 45Q tax credit for carbon sequestration to make the production of low-emissions ammonia profitable. In China, construction began on multiple projects in Uxin Banner, Inner Mongolia. This included a USD 0.6 billion project being developed by China Coal that will produce around 20 ktpa hydrogen (H_2) for methanol synthesis, and a USD 1.5 billion project being developed by Zhongtian Hechuang Energy, of which USD 235 million is for hydrogen, to produce 30 ktpa H_2. Both projects are expected to be completed between 2026 and 2027.

Delays and cost inflation remain widespread. In some cases, these delays are due to cost uncertainties, which are preventing projects from reaching FID (see section on barriers to reaching FID). For example, when construction of the NEOM Green Hydrogen project (which includes a 2.2 GW electrolysis plant and ammonia production) began in Saudi Arabia in 2023, the FID was taken on a revised budget of USD 8.5 billion. This is 70% higher than the USD 5 billion estimated during early planning. This increase reflects inflation since 2020, financing costs, and additional upfront investments, such as advance payment of land acquisition fees, power transmission infrastructure and other measures to reduce long-term operational costs.

Sources of finance for hydrogen projects under construction

Low-emissions hydrogen projects are being financed through a mix of corporate balance sheet funding and project finance structures, with the choice depending on the project's scale and maturity, and its developers. In both cases, public support – such as via grants, tax incentives, or concessional finance – remains a key component of overall funding.

Established industrial companies may opt to fund projects directly using internal cash reserves or retained earnings, which is commonly referred to as balance sheet financing. This allows them to avoid external debt or equity issuance, but means that financial risk is concentrated on their own books. While financing details are often undisclosed, it is likely that smaller projects backed by major industrial players use balance sheet funding.

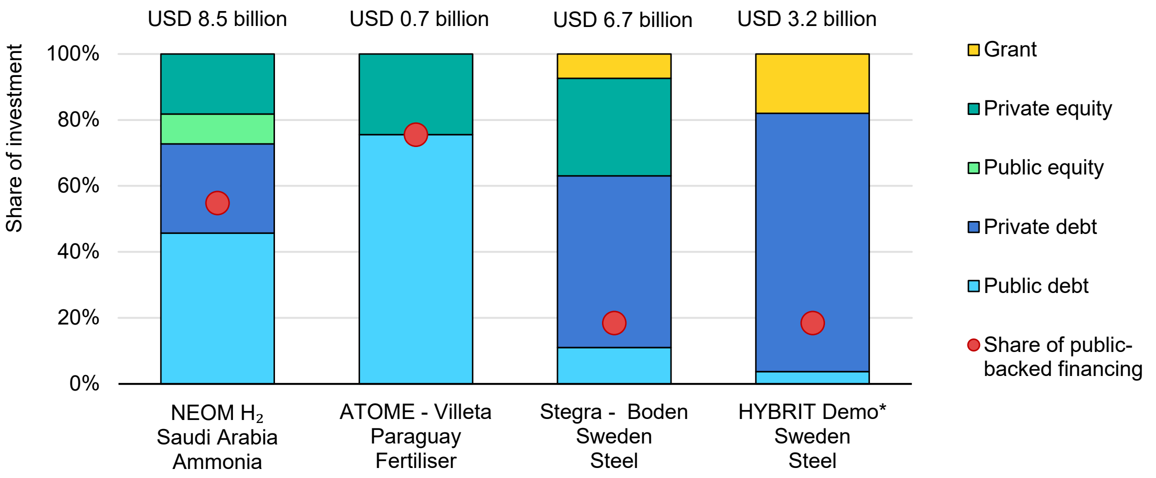
For capital-intensive or large-scale projects, developers often establish joint ventures (JVs) and may create special purpose vehicles (SPVs) or project companies to pool resources, share risks, and isolate liabilities from corporate balance sheets. JV partners typically provide initial equity contributions, while the JV itself or a designated SPV may also secure public grants, concessional finance, or external debt to meet total investment requirements. Examples of this model include:

- NEOM Green Hydrogen Company, a JV between ACWA Power, Air Products and NEOM to produce low-emissions ammonia using electrolytic hydrogen in Saudi Arabia.
- HYBRIT Development AB, a JV between SSAB, LKAB and Vattenfall, which is behind the HYBRIT project in Sweden to produce low-emissions steel using electrolytic hydrogen.
- The Castellón Green Hydrogen JV in Spain, a 50/50 partnership between BP and Iberdrola, developing a 25 MW electrolyser at off-taker BP's refinery.

- A JV announced in 2025 between CF Industries, JERA, and Mitsui (holding 40%, 35% and 25%, respectively) to construct an autothermal reforming plant for low-emissions ammonia at CF's Blue Point Complex in Louisiana.

Each low-emissions hydrogen project is still unique, as the market is maturing, and financing typically relies on a combination of public grants, equity contributions from public or private entities, and debt financing, including both concessional and commercial sources. Project developers and SPVs typically adopt project finance structures that raise capital at the project level through a mix of debt and equity from multiple investors. This approach facilitates risk-sharing and can attract external capital, though it often requires long-term offtake agreements.

Figure 5.2. Estimated financing structure of selected electrolytic hydrogen projects



* The HYBRIT Demo project is part of a joint venture between well-established industrial companies. Part of the project funding may come from equity contributions of the parent companies or directly from balance sheet of these companies, which are unknown. As a result, no equity tranche is shown in the capital stack. The Swedish National Debt Office reported total project investment at around EUR 4.5 billion. The estimated financing structure of ATOME's project assumes that the project reaches final investment decision (FID).

Notes: H_2 = hydrogen. Total project costs are at the time of announcement and have not been inflated. The four projects illustrated were selected based on the availability of public information on financing structures beyond corporate balance sheet funding.

Source: IEA analysis based on data from IJGlobal (2025).

Projects rely on blended finance structures that combine equity with loans and guarantees from public financial institutions, while grants remain limited.

Public support through non-repayable grants plays a crucial role in reducing private sector risks for the first large-scale low-emissions hydrogen projects. Both the Stegra and HYBRIT projects have received grant funding from sources including the EU Innovation Fund, the Just Transition Fund (via the European Union and the Swedish Agency for Economic and Regional Growth) and Sweden's Industriklivet programme. These projects aim not only to produce electrolytic hydrogen at scale, but also to demonstrate for the first time the direct reduction of iron ore using 100% hydrogen, a process not yet commercially proven. Demonstrating this technology offers a pathway to decarbonise steelmaking and strengthen the competitiveness of European industry. Despite this public support, government grants cover a relatively small share of total project costs. In contrast, the NEOM project has not received traditional grant funding, but instead benefits from large state-backed debt and equity investment from government-linked entities. NEOM, which is fully owned by the Saudi sovereign wealth fund, Public Investment Fund (PIF), holds a one-third stake in the project. ACWA Power holds another one-third stake, with PIF also holding an indirect stake via its shareholding in ACWA Power, reported at roughly 44-50% in recent disclosures. The Saudi government therefore has a significant equity stake in the project, which not only provides access to public capital but also mitigates country-specific investment risk.

Grants may help to absorb early-stage risks arising from the high uncertainty and potential sunk costs of feasibility studies and other development expenditures (DEVEX)[65] by reducing the need for scarce or expensive equity or debt at initial stages. However, public and private debt and equity ultimately provide the bulk of project capital once the project has reached a more advanced stage.[66] Debt is generally less costly than equity, as equity investors demand higher returns to compensate for their exposure to project risk and performance. A higher debt-to-equity ratio typically translates into a lower levelised cost of hydrogen. While conventional renewable energy projects often target a ratio of 80:20, more complex or riskier projects – such as low-emissions hydrogen plants – may feature greater shares of equity. Projects such as NEOM, Stegra and ATOME display debt-to-equity ratios in the range of 65:35 to 75:25 (Figure 5.2). The planned Freija Clean Fuel project in Finland has announced it will seek a debt-to-equity ratio of around 60:40. While the shares of debt and equity are relatively similar across the projects, the composition and cost of debt varies:

- For the NEOM project, over 60% of debt is sourced from state-owned and development banks offering longer tenures, including 20% debt coming from the Saudi Industrial Development Fund (SIDF).[67] Around 5% of the debt is backed by direct lending from Germany's export credit agency[68] (ECA), Euler Hermes, to finance electrolysers supplied by thyssenkrupp nucera from Germany. Of the total debt, around 95% is senior debt, with the remainder structured as mezzanine debt[69] facilities.

[65] DEVEX represents the cost associated with developing a project up to the point of financial close or construction.

[66] Early-stage risk stems from the uncertainty of whether a project will proceed, making initial investments in feasibility studies and DEVEX potentially unrecoverable liabilities if the project is not realised.

[67] While the loan rate for this project is undisclosed, some SIDF loans bear no interest and borrowers pay service fees, whereas the company NAMA Chemicals reported an effective interest rate of 1.71% at the end of 2023.

[68] An export credit agency (ECA) is a public or quasi-public institution that provides government-backed loans, guarantees, or insurance to support domestic companies in exporting goods and services, typically by reducing the financial risks associated with international trade.

[69] Senior debt refers to loans with repayment priority, typically secured against project assets and associated with lower risk and interest rates. Mezzanine debt ranks below senior debt in the repayment hierarchy, carries higher risk, and generally offers higher returns to compensate for its subordinate position.

- In ATOME's Paraguay project (which is pending FID at the time of writing), the entire debt portion would come from government-backed lenders, including a senior debt package being prepared by the Inter-American Development Bank, the European Investment Bank (EIB) and the Dutch Entrepreneurial Development Bank (FMO), supplemented by USD 50 million of concessional finance from the Green Climate Fund to reduce the cost of capital (Table 5.1).
- In contrast, the debt financing structures of the Swedish Stegra and HYBRIT projects rely primarily on private capital. Stegra's project sources less than 20% of its debt from public institutions, including the Swedish ECA (SEK), the German ECA (Euler Hermes), and the European Investment Bank and the Nordic Investment Bank (NIB), while HYBRIT sources less than 5% from the NIB. Public debt can be used to crowd in private investment, with commercial banks providing most of the funding on shorter tenures. In Stegra's case, around 85% of the debt is structured as senior debt, complemented by a mezzanine facility. As such, while public financial institutions contribute a smaller share of the overall debt, most of the senior debt is backed by loan guarantees from the Swedish National Debt Office (Riksgälden), covering 80% of the loan amount, and Germany's ECA, covering 95%, each up to a maximum of EUR 1.2 billion. In the HYBRIT project, Riksgälden provides a EUR 1.1 billion loan guarantee covering 80% of the loan facility.

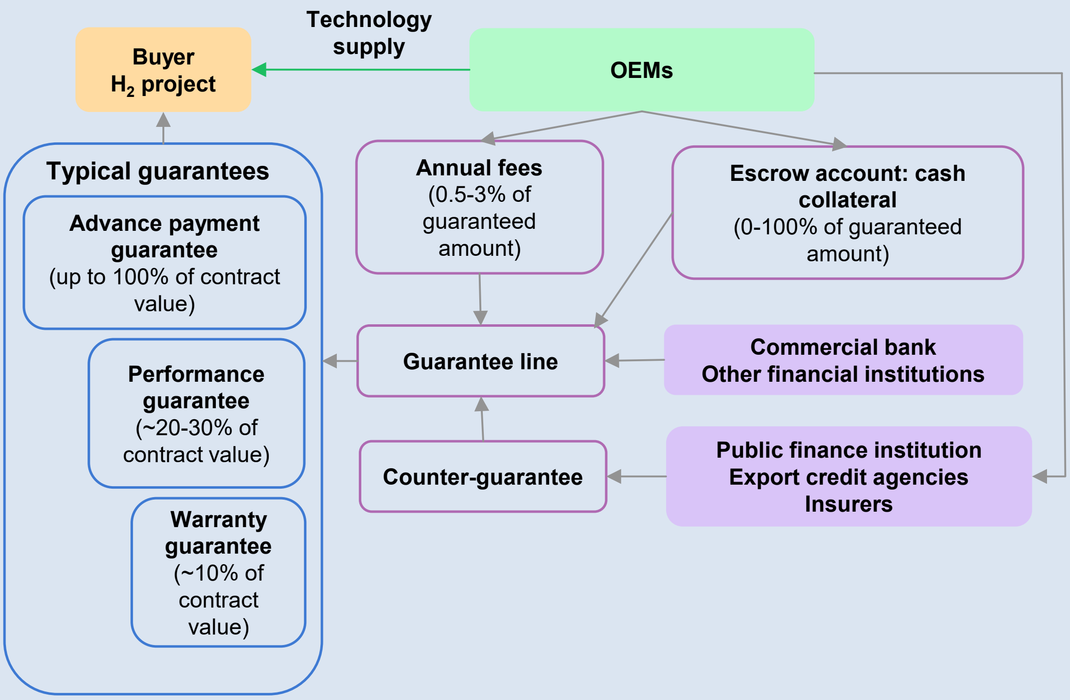
Offtake agreements and financing are closely interlinked. Off-takers often act as equity investors, aligning their commercial interests with the success of the project. They also enable external financing by reducing commercial risk and providing revenue certainty. For example, Air Products holds the remaining third equity stake in the NEOM JV and has signed a 30-year offtake agreement for all the ammonia produced. The Stegra project has secured several binding offtake agreements with Marcegaglia, Mercedes-Benz, Scania and Schaeffler, among others, who have also invested equity in the project. ATOME Energy's Villeta project has not yet finalised offtake agreements, but has signed a non-binding Heads of terms agreement with Hy24's Clean H_2 Infra Fund. This is set to become the lead equity investor, and has committed USD 100–115 million post-FID, though this is contingent on finalising offtake agreements, for which a non-binding deal has been signed with Yara.

Box 5.1 Reducing cash collateral needs for manufacturers: sharing technology-related risks

Hydrogen projects, particularly those involving new technologies or first-of-a-kind deployments at scale, may encounter challenges in terms of bankability due to high upfront capital requirements, lengthy project timelines and potential performance risks. To mitigate these risks, project developers and equipment suppliers often need to provide guarantees to buyers and financiers, both to strengthen confidence in the OEM's ability to deliver and maintain the equipment, and to offer financial compensation in the event of non-performance, even if such compensation may not fully offset the potential impact.

Technology manufacturers are often asked to provide buyers with guarantees that provide insurance against non-delivery, underperformance or failure. Companies often have bank guarantee facilities that incur annual fees ranging from 0.5%-3% of the guaranteed amount, with well-established manufacturers typically paying fees at the lower end of this range. Banks may also require manufacturers to provide cash collateral to secure the guarantee facility, which may be in the form of cash deposits, liens on assets or other financial instruments. The amount of collateral required ranges from 0-100%, depending on the manufacturer's risk assessment.

Illustrative structure of guarantee instruments supporting original equipment manufacturers and buyers



Notes: OEMs = original equipment manufacturers. Contractual guarantees evolve throughout the product delivery phase, reflecting changes in risk exposure from delivery to long-term performance. An advance payment guarantee is usually issued when the contract is signed to secure any upfront payments made to the OEMs, and it remains in place until the equipment is delivered. Afterwards, the advance payment guarantee is released and replaced by a performance guarantee, which ensures that the equipment meets the technical and operational criteria agreed in the contract. Following commissioning and successful performance testing – often over a specified period – the performance guarantee may be reduced or replaced by a warranty guarantee. This final guarantee ensures coverage for latent defects or underperformance during the warranty period, which can range in length up to several years depending on the contractual terms.

Although guarantees are standard for renewable energy equipment, meeting large order backlogs can put established suppliers under strain, particularly for advance payment guarantees. For instance, Siemens Gamesa – which had orders worth over EUR 40 billion for wind turbines – secured a EUR 1.2 billion guarantee facility in 2024, 50% of which is backed by Spain's ECA, CESCE. In 2023, the German government had also provided a counter-guaranteed EUR 7.5 billion of a EUR 12 billion facility for broader support to Siemens Energy, which in 2025 has been replaced by a bank facility from commercial banks. Some of the wind turbines may be supplied to projects related to hydrogen production.

Providing guarantees or cash collateral can be difficult for emerging supply chains, particularly those involving innovative technologies from start-ups without a proven performance record. Some manufacturers are unable to offer guarantees as they do not yet have enough operational data on which to base such commitments. While this can be expected to improve as the technology and market mature, it remains problematic during the scale-up phase. More established players may be able to obtain a guarantee through a subsidiary or parent company. Some firms are already offering performance guarantees for hydrogen-related technologies. These include KBR for its ammonia cracking technology, Topsoe for the availability and efficiency of its electrolysers, and Nel Hydrogen with Samsung E&G for their CompassH2 electrolyser package, among others. However, guarantee requirements can tie up to 100% of the contract value in cash collateral for newer or smaller companies, which significantly constrains their liquidity and diverts capital from innovation and scale-up.

Insurers can also issue guarantees that help spread the risks of hydrogen projects by transferring part of the risk, thereby improving OEM liquidity by reducing cash collateral needs, and increasing investor confidence, particularly among risk-averse lenders such as pension funds, as they typically provide investment-grade guarantees. For example, re-insurer Munich Re has developed the HySure product for electrolysers, providing guarantees on the equipment and its performance. Similarly, Ariel Green can provide commissioning and performance guarantees for a range of hydrogen-related equipment, including electrolysers, steam methane reforming and autothermal reforming with CCUS. In January 2025, Topsoe announced New Energy Risk as its preferred insurance partner for its solid oxide electrolysers, offering customers access to Technology Performance Insurance (TPI)*.

While TPI can help lower the cost of capital by de-risking investments, the associated premium can affect the overall economics of the project. Striking the right balance is therefore essential to ensure project feasibility. To alleviate this issue, public finance institutions and ECAs are increasingly stepping in to provide support, providing guarantees to bridge the technology risk gap. ECAs also enable domestic manufacturers to compete globally, as they offer guarantees in support of domestic exports, often on a tied basis. Recent support from public finance institutions includes:

- In January 2025, electrolyser-manufacturer Sunfire announced it had secured 5-year EUR 200 million guarantee line financing provided by European commercial banks, with 80% of the line secured by parallel default guarantees from the German Federal Government and the Free State of Saxony. The guarantee line eliminates the need for Sunfire to provide cash collateral.
- In June 2025, the European Investment Bank approved the first wave of instruments under the TechEU programme to support cleantech, in line with the EU Clean Industrial Deal. This includes a EUR 250 million CleantechEU guarantee scheme for small and medium-size enterprises, which could potentially support hydrogen-related technologies.

Collaboration between OEMs, ECAs, commercial banks, and (re)insurers remains essential to unlock financing at scale for hydrogen projects. Between 2016 and 2020, only 0.2% of performance guarantees were invoked and Siemens Energy suggests default rates of less than 0.5%, suggesting that financial exposure for providers is relatively low. However, this rate may vary across sectors and may not yet fully reflect the specific risk profile of the hydrogen sector, particularly for less established manufacturers. Beyond risk mitigation, the technical due diligence conducted by guarantors signals technology reliability to project developers and strengthens investor confidence in the overall project.

* TPI is a specialised risk mitigation tool designed to protect against financial losses from the underperformance or failure of emerging technologies. TPI covers gaps in performance guarantees, particularly where EPC contractors are unable or unwilling to provide them, often for novel technologies. TPIs can assume debt service and principal repayments in the event of underperformance. Coverage can reach up to USD 400 million per transaction, with premiums ranging from 4–10% of the insured amount, depending on technology maturity (e.g. TRL, track record, and the experience of licensors and EPCs). Terms can often extend up to 10 years, aligned with warranty or debt tenures.

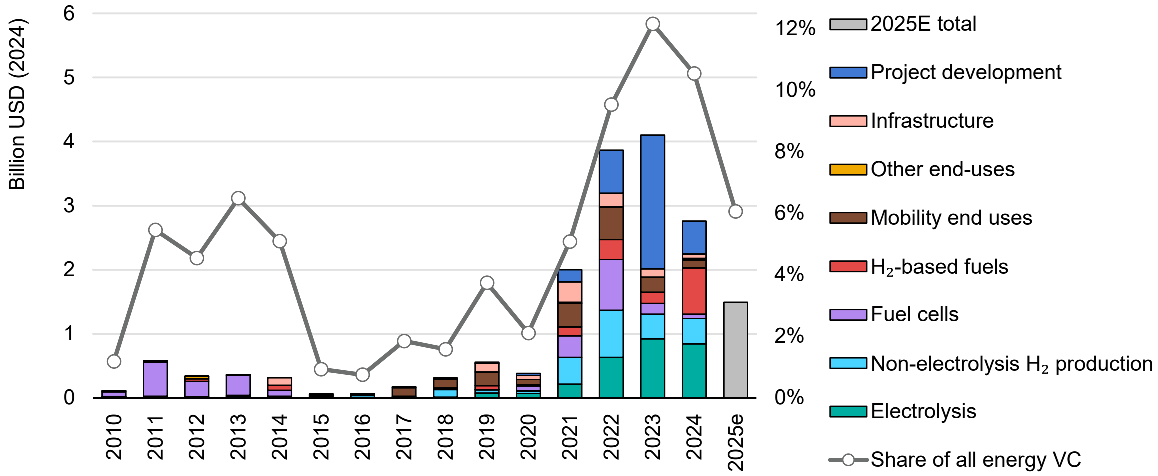
Venture capital investment in young hydrogen companies

Since 2021, 290 hydrogen-related start-ups have raised VC equity worldwide. This is more than double the number that raised VC funding in the 5 years from 2016 to 2020. Furthermore, these start-ups have raised more than USD 14 billion since 2021, almost ten times the USD 1.5 billion secured over the previous 5 years. As the commercial prospects for hydrogen technologies improved with governments' commitments to net zero emissions, so did the size of deals offered to innovators: in 2021, more than 90% of the funding was to developers of hardware technology. This represented a major injection of capital for entrepreneurs to take the risk of scaling up new technologies in the expectation that they would perform competitively and find a receptive market this decade.

Since 2021, 9% of all energy-related VC has been directed to hydrogen start-ups, a proportion that peaked at 12% in 2023, substantially more than the 2% share from 2016 to 2020.

However, VC fundraising by hydrogen start-ups has been in decline since 2023, falling one-third in 2024. Based on data from the first half of 2025, we estimate that it could fall by more than 40% in 2025. This follows a wider trend in energy-related VC, which is largely a consequence of broader macroeconomic trends. The ramp-up in VC funding for hydrogen start-ups from 2021 occurred at the same time as greater interest in hydrogen as a means of meeting industrial and climate policy targets coincided with low interest rates. From 2023, interest rates rose, making equity investments in start-ups riskier propositions compared with other investment options, and many private investors reallocated capital away from VC markets.

Figure 5.3. Venture capital investment in energy start-ups in hydrogen-related areas, per technology domain, 2010-2025



Notes: H_2 = hydrogen; VC = venture capital. Project development category includes start-ups that do not own intellectual property on technology and raise funds for supply-side project development costs. Other end uses include steel production, chemicals, waste management and heating. 2025e is a full-year estimate for all hydrogen-related VC based on data up to H1 2025, which does not provide a high enough confidence level for a breakdown by technology area.
Sources: IEA analysis based on Cleantech Group (2025) and Crunchbase (2025).

VC funding for hydrogen start-ups fell in 2024 despite rising non-project investments, and the drop exceeded that in the wider energy-related VC market.

This phenomenon was not limited to energy start-ups, whose fundraising has been slightly more resilient than other VC segments, with the notable exception of artificial intelligence (AI), which has attracted increased investor interest as capital shifts away from capital-intensive solutions. While VC for hydrogen still rose in 2023, total energy-related VC shrank. However, this divergence can be largely attributed to a single large growth-stage deal for Stegra, and the subsequent decline in VC for hydrogen has been steeper than energy-related VC in total. Some of the decline may be reversed in the coming years by investments from a large new hydrogen-focused VC fund announced in May 2025 by Chinese Sinopec. If the allocated fund, of roughly USD 690 million, were invested over 5 years, the annualised investments would be equivalent to 5% of the 2024 global VC total for hydrogen. However, the priorities, scope and regional focus of the fund remain undisclosed.

Among technology areas, start-ups developing technologies for the production of low-emissions hydrogen and derivatives have been most resilient to the recent downturn in VC funding. The largest amount of funds raised in 2024 was by Koloma, a US developer of technology to explore and exploit geologic hydrogen deposits, which raised nearly USD 300 million alongside USD 0.9 million in a US government grant. Electrolyser innovators and developers of hydrogen-based fuels attracted 64% of the remaining VC funding flowing to hydrogen start-ups. In 2024, Sunfire, a German solid oxide electrolyser (SOEC) developer, raised EUR 215 million and secured a loan of EUR 100 million from the EIB. HySata, an Australian developer of capillary-fed alkaline electrolysers, raised USD 111 million. Sunshine Hydrogen, a Chinese alkaline electrolyser developer, raised USD 92 million. Utility Global, a US developer of reactors that convert steam and off-gases into hydrogen without electricity, raised USD 53 million. The largest example of funds raised among hydrogen-based fuels companies was by US-firm Infinium, raising more than USD 200 million across 2024 and 2025. Germany's INERATEC followed, with USD 129 million, while US-based Air Company raised USD 69 million.

Performance of hydrogen companies on public markets

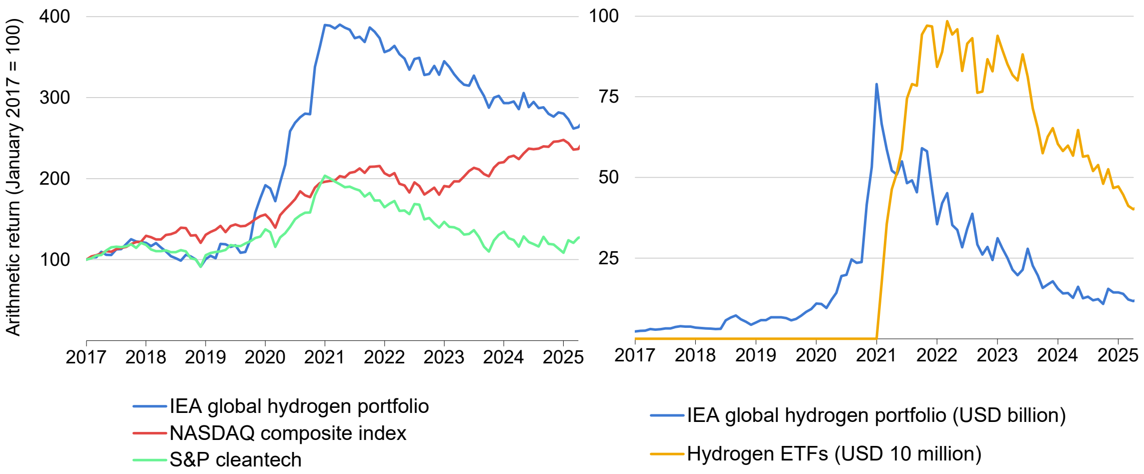
Data on the performance of publicly traded companies sheds light how companies working on hydrogen projects are performing, both in terms of their cashflow and ability to raise funds, as well as the expectations of investors. While not all companies active in hydrogen are listed, and many that are have significant operations outside hydrogen, there is a globally representative set of listed firms whose finances are inextricably linked to the health of the low-emissions hydrogen sector. We have assembled a portfolio of 51 publicly traded companies in the sector to track their performance and assess sectoral trends.[70]

Companies in this portfolio have continued to face challenges in the time since the publication of GHR-24. Many are scaling up new businesses and therefore necessarily putting significant capital at risk (e.g. in factories or project equity) to

[70] Since GHR-24, four companies have been added: Cavendish Hydrogen, listed on the Oslo Stock Exchange in June 2024; Primary Hydrogen Corp, incorporated in November 2024; Jiangsu Guofu Hydrogen Energy, listed on the Hong Kong Stock Exchange in November 2024; and Refire Energy, listed on the Hong Kong Stock Exchange in December 2024.

be able to take orders for equipment sales. While many have signed agreements with project developers, these often do not translate into firm contracts and revenues unless the pace of project FID accelerates. At the same time, most of these companies are relatively young, with weak balance sheets that have come under further pressure from higher costs of capital and costs of inputs.

Figure 5.4. Monthly returns (left) and market capitalisation (right) of hydrogen companies, hydrogen funds and relevant benchmarks, 2017-2025



Notes: ETFs = exchange-traded funds. Monthly return = closing price on last day of month divided by closing price on last day of previous month. IEA's global hydrogen technology portfolio includes 51 public companies whose value is driven primarily by the outlook for low-emissions hydrogen and the tickers of included firms are 2570 HK; 2582 HK, 288620 KS, 336260 KS, 702 HK, ACH NO, ADN US, AFC LN, ALHAF FP, ALHRS FP, AMMPF US, AQUNU US, ATOM LN, BE US, BLDP CN, CASAL SW, CAVEN NO, CH CN, CI SS, CPH2 LN, CWR LN, F3C GY, FCEL US, FHYD CN, GHY AU, GNCL IT, GREENH DC, H2A GR, H2O GY, HDF FP, HDRO CN, HTOO US, HYPRO NO, HYSR US, HYT AU, HYZN US, HZR AU, IMPC SS, ITM LN, LHYFE FP, NCH2 GY, NEL NO, NHHH CV, NXH CN, PCELL SS, PHE LN, PLUG US, PPS LN, PV1 AU, SPN AU, TECO NO. S&P cleantech refers to the S&P/TSX Renewable Energy and Clean Technology Index.
Source: IEA analysis based on Bloomberg terminal data.

Despite more hydrogen projects attracting investment, financial markets continue to be cautious about the prospects of pure-play hydrogen companies in the supply chain.

The monthly investor returns and revenues of this portfolio have declined over the past year. This trend is evident internationally; for example, Jiangsu Guofu Hydrogen Energy, a Chinese electrolyser company listed on the Hong Kong Stock Exchange in November 2024, saw its share price fall by 20% between January and June 2025. In contrast, the broader S&P cleantech index, which covers clean technologies beyond hydrogen, stabilised after three straight years of decline. As noted in GHR-24, an even broader technology-led index, the NASDAQ, has followed a divergent growth trend since mid-2022, driven by strong performance of digital technology firms, especially those active in AI. A similar recovery for hydrogen equities could occur if project pipelines expand and a consistent flow of FIDs adds enough capacity by 2030 to produce 5 Mtpa of low-emissions hydrogen, a trajectory deemed likely with sufficient policy support (see Chapter 3

Hydrogen production). Despite recent declines, a dollar invested evenly across the hydrogen portfolio in 2017 (and as additional portfolio companies listed) would still have outperformed a dollar invested in either the NASDAQ or clean technology indexes, due to the sharp growth achieved by hydrogen firms during the 2020-2021 surge in listings, and to investors' enthusiasm.

The combined capitalisation of firms already in the portfolio by mid-2024 has continued on a downward trajectory since GHR-24. This decline reflects firms drawing on balance sheets to fund R&D and factories while revenue is not yet covering costs, alongside falling share prices amid weakening investor confidence in near-term returns. However, new entrants have lifted the overall capitalisation of the portfolio back to the level of early 2024. At around USD 3 billion, the combined capitalisation of Refire Energy and Jiangsu Guofu Hydrogen Energy, two Chinese companies, is the largest contributor in this regard. Without these additions to the portfolio, over 90% of the accumulated value accrued in 2020 and 2021 from initial share sales would have been wiped out by mid-2025.

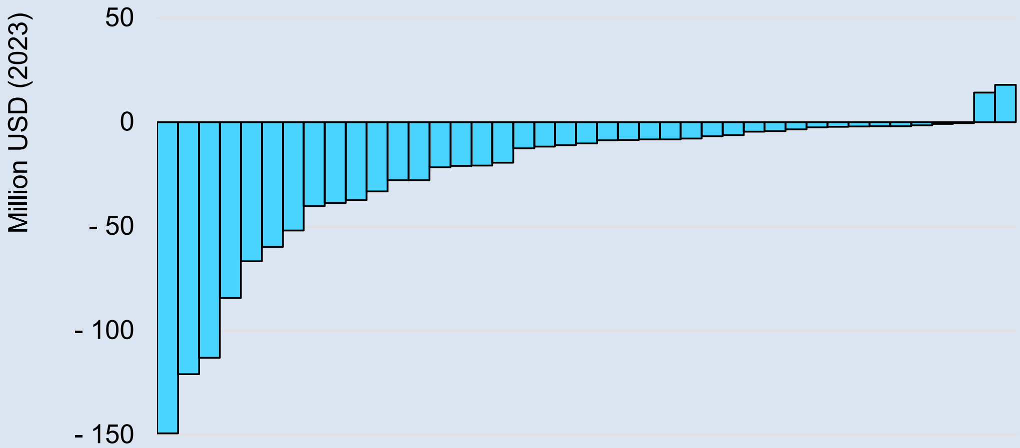
Specialist exchange-traded hydrogen funds that raise money to allocate as debt or equity to hydrogen companies or projects have continued to lose value since GHR-24. This reflects the fact that funds, mostly set up around 2021, have been spending and not replenishing their capital, as well as investors' scepticism about the near-term profitability of hydrogen investments. The managers of the USD 8 million HydrogenOne Capital Growth fund announced in July 2025 that it will be wound up due to underperformance. No new funds have been launched. The Clean H2 Infra Fund, though not publicly traded, has continued to spend the EUR 2 billion (USD 2.1 billion) raised in 2022.

Box 5.2 Rising financial distress for hydrogen companies

As hydrogen companies mature, some seek to pursue public listing or attract acquisition offers to access capital and provide returns to early investors. However, many face financial challenges throughout their development, leading, in some cases, to bankruptcy filings followed by restructuring efforts or, where recovery is not viable, liquidation and cessation of operations. In 2024–2025, the hydrogen sector saw limited public listings, with only a few notable initial public offerings (IPOs), Refire and Jiangsu Guofu Hydrogen Energy, both debuting on the Hong Kong Stock Exchange, and Hydrogenera on the Bulgarian Stock Exchange. Stegra has started preliminary work toward a public listing to support its expansion plans.

By contrast, an increasing number of companies faced financial difficulties, underscoring the ongoing challenges of commercialisation, particularly for manufacturers. Some firms expanded rapidly in anticipation of faster scale-up of the low-emissions hydrogen sector and may have been overvalued during early 2020s funding rounds, at a time when investor sentiment was more optimistic. As market conditions tighten, several of these companies are now shifting from manufacturing towards innovation and technology licensing, seeking to build partnerships while avoiding the capital intensity of manufacturing.

EBITDA of selected hydrogen companies, 2023



Notes: EBITDA = Earnings before interest, taxes, depreciation and amortisation. Data were available for 42 of the 51 companies in the IEA Global Hydrogen Portfolio; only these are included in the analysis. Plug Power is excluded from the graphical representation to avoid axis distortion as it reported an EBITDA of USD - 1.3 billion in 2023.

Source: IEA analysis based on Bloomberg terminal data.

Pure-play hydrogen companies typically report negative EBITDA, as they prioritise growth and technology development over near-term profitability. In their early stages, hardware-focused start-ups often operate at a loss for extended periods due to the high capital requirements of developing and scaling new technologies. Their survival depends on sustained investor confidence and access to patient capital, especially as they navigate the multiple "valleys of death" that characterise innovation, periods where companies face high costs and limited revenue. As a point of comparison, Tesla remained unprofitable for nearly 17 years before achieving sustained profitability. However, not all companies manage to bridge these gaps; some face delays in orders or struggle to secure financing, eventually running out of cash. In contrast, established industrial players with hydrogen as part of a broader portfolio are often able to weather early losses, using revenues from core operations to support longer-term hydrogen developments.

In October 2024, hydrogen **truck manufacturer** Hydrogen Vehicle Systems entered insolvency proceedings in the United Kingdom, followed by fellow truck-maker Hyzon Motors, which began dissolving operations and, in March 2025, got shareholder approval for delisting and liquidation. Around the same time, German hydrogen truck manufacturer Quantron filed for bankruptcy, later announcing in April 2025 that it had exited insolvency and would reposition, though its revised strategy has not yet been disclosed. In early 2025, the trend intensified. In February, hydrogen fuel cell electric truck manufacturer, Nikola Corporation, filed for Chapter 11 bankruptcy in the United States, with Lucid Group later acquiring selected manufacturing assets, but excluding Nikola's truck technology or customer base. Around the same time, Hyvia, a joint venture between Renault and Plug Power, entered legal liquidation, while Cummins acquired selected assets from First Mode following its bankruptcy, including hybrid powertrain solutions for mining and rail applications. In May 2025, Hynion's Swedish subsidiary (Hynion Sverige), a hydrogen refuelling station operator, filed for bankruptcy.

Hydrogen-related **aviation** companies are also facing headwinds, particularly due to the high capital intensity of R&D and uncertain market demand. In mid-2024, Universal Hydrogen – a US start-up developing hydrogen-electric propulsion systems – ceased operations after failing to secure additional funding or a strategic buyer. In March 2025, Germany's APUS Zero Emission entered provisional insolvency proceedings, pending a decision on whether the company can continue operations or proceed to full liquidation.

Electrolyser and fuel cell manufacturers have also faced mounting financial pressure. In July 2024, Canadian fuel cell manufacturer Loop Energy filed a Notice of Intention under Canada's Bankruptcy and Insolvency Act, initiating court-supervised restructuring; it was later acquired in December 2024 by Teralta Hydrogen Solutions. In April 2025, McPhy launched a court-supervised sale process and announced plans for liquidation in May after receiving no viable bids. In July 2025, the court approved John Cockerill's acquisition of McPhy, including its manufacturing facility and most of its workforce. In June 2025, thyssenkrupp nucera signed an agreement to acquire Green Hydrogen Systems' intellectual property and a test facility, with the company announcing its intention to file for bankruptcy after the in-court restructuring process failed to secure financing. Meanwhile, GTT launched a strategic review of its electrolyser subsidiary Elogen, with plans to shift its focus away from manufacturing and reposition around R&D, a shift in focus that has also been seen in other companies (see Chapter 3 Hydrogen production).

In November 2024, **project developer** HH2E initiated insolvency proceedings due to lack of funding, and in July 2025, H2APEX completed its acquisition, becoming the owner of a planned 1 GW project in Germany.

Some companies have narrowly avoided similar outcomes. In the absence of strong EBITDA, firms may rely on equity to fund operations, as seen with electrolyser OEMs Clean Power Hydrogen and Plug Power, and project developer Charbone, which issued new shares in the past year. Plug Power's USD 525 million credit facility secured in April 2025 was intended to reduce further equity dilution at that time.

As the sector continues to evolve, striking the right balance between innovation, recalibration after the initial wave of enthusiasm, organisational agility and financial discipline will be essential for its maturation and eventual consolidation. Companies will also need to define their strategic positioning, whether to scale as manufacturers or focus on R&D and technology licensing. Even when companies shut down, whether through restructuring, acquisition, or liquidation, their technological know-how is often transferred or absorbed, preserving innovation and contributing to broader industry learning. The tricky path to profitability, often lengthy and marked by downturns, is one that other technology sectors, such as solar PV, electric vehicles and semiconductors, have also navigated.

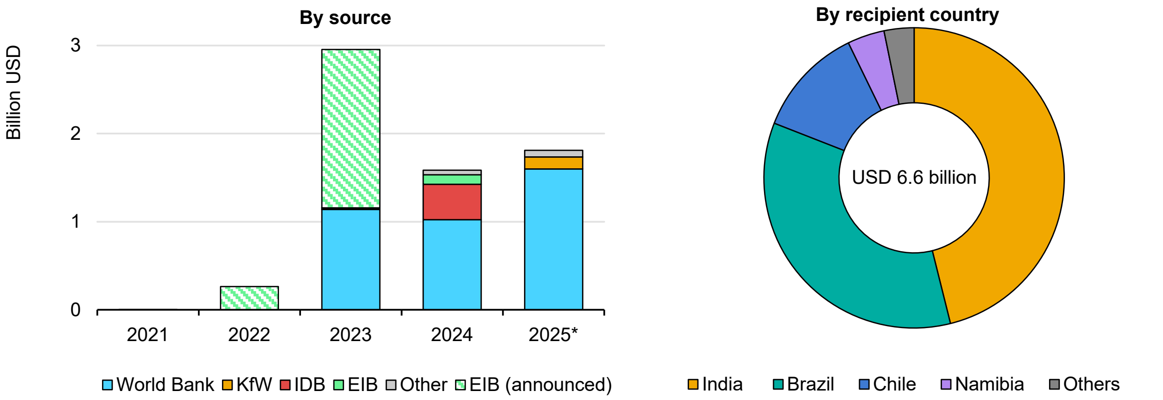
Development finance institutions are laying the groundwork for low-emissions hydrogen in EMDEs

Development finance institutions (DFIs) account for only around 1% of total energy sector financing, but their role in shaping clean energy transitions in emerging markets and developing economies (EMDEs) is far greater than that share suggests. By supporting early-stage, high-risk projects that may not yet attract commercial funding, DFIs play a critical role in enabling investment, de-risking technologies, and laying the groundwork for long-term, transformative development. Their support often extends beyond capital, including sector-specific policy engagement and technical assistance to build local capacity. Around 30% of the production from announced low-emissions hydrogen projects, and more specifically nearly 40% of electrolytic hydrogen production, comes from projects that are planned in EMDEs other than China, where successful deployment could support industrial development and export-oriented growth. With FIDs in hydrogen projects still limited in most EMDEs (5% compared with a global average of 11%), DFIs could play a critical role in filling early-stage funding gaps and enabling the project pipeline to mature.

DFI funding in low-emissions hydrogen rose sharply between 2022 and 2025, from virtually zero to USD 4.6 billion in committed funding, with an additional USD 2.1 billion announced and pending final approval. In 2023, announcements reached a historic high of USD 4.8 billion, though only USD 1.2 billion was committed that year. While announcements slowed in 2024 and 2025, commitments increased, rising to USD 1.6 billion in 2024 and USD 1.8 billion by mid-2025, partly consolidating earlier announcements. For context, DFIs disbursed an average of USD 24 billion annually to energy-related projects between 2019 and 2022. If they are eventually disbursed, recent hydrogen-related announcements could account for a notable share of broader energy financing by DFIs.

The majority of DFI financing for hydrogen projects, considering both announced and committed funds, is in the form of loans. These account for over 95% of announced support, followed by smaller volumes of grants and minimal equity investment. However, due to the early stage of hydrogen development in many EMDEs, disbursements to date have focused primarily on technical assistance. These grants – often aimed at feasibility studies, capacity-building and regulatory scoping – are essential for preparing the ground for future investment. In many cases, basic sectoral knowledge, institutional readiness and project pipelines must be established before large-scale capital can be deployed effectively.

Figure 5.5. Funding allocated by development finance institutions to countries for low-emissions hydrogen, 2021-2025



Notes: EIB = European Investment Bank; IDB = Inter-American Development Bank; KfW = Kreditanstalt für Wiederaufbau (Germany´s development bank). Unless otherwise indicated, funding is committed. For 2025, data are as of mid-2025.
Source: IEA analysis based on the publicly available information until June 2025.

Since 2022, India, Brazil and Chile have been the recipients of the most DFI funding for hydrogen, with the World Bank and IDB accounting for over 90% of the total committed.

The World Bank has accounted for more than half of announced or committed DFI funding for hydrogen over the past 4 years. Notably, in 2024 it approved a second USD 1.5 billion Development Policy Loan[71] for India's Low-Carbon Energy Programme, building on a similar loan approved in 2023, with the aim of supporting the production of 450 ktpa of low-emissions hydrogen and 1.5 GW of electrolyser capacity by 2026. In 2025, Mauritania´s DREAM Project was approved, with USD 82.5 million in Investment Project Financing for blended finance and capacity-building, while Brazil anticipates Investment Project Financing approvals of USD 1.6 billion in FY2025.

[71] Development Policy financing provides budgetary support to governments for implementing policy and institutional reforms, whereas Investment Project Finance is used to finance specific projects, focusing on tangible outcomes, such as building a hydrogen plant.

In March 2025, the Team Europe Renewable Hydrogen Funding Platform for Chile, implemented by CORFO under its Green Hydrogen Facility, announced committed loans of EUR 100 million each from the EIB and Germany's KfW, alongside a EUR 16.5 million grant from the EU Latin America and Caribbean Investment Facility. The programme targets at least 150 MW of new electrolyser capacity and aims to crowd in additional funding, including from export credit agencies. In September 2024, the European Union also announced a EUR 32 million grant to support hydrogen development in South Africa, partly channelled through the French DFI AFD.

Beyond sovereign lending, DFIs also support the private sector to develop hydrogen projects in EMDEs. In November 2024, IDB Invest – the private sector arm of the Inter-American Development Bank – proposed a USD 200 million loan to finance ATOME's hydrogen project in Paraguay. As of December 2023, the International Finance Corporation (IFC), the private sector arm of the World Bank, reported that it was involved in nearly a dozen hydrogen projects globally, with potential investments exceeding USD 10 billion. In December 2023, IFC and Transition Industries signed a Joint Partnership Development Agreement for the USD 3.3 billion Pacífico Mexinol project in Mexico to produce 0.3 Mtpa of methanol from electrolysis and 1.8 Mtpa from natural gas with CCUS, with first engineering contracts awarded in June 2025. In addition to direct financing, the IFC provides regulatory support and feasibility studies to help projects reach investment readiness, addressing a challenge often raised by developers in EMDEs, who underline the critical role of DEVEX in bridging the pre-FID gap, particularly as FIDs require time (and money) to materialise. Appraisal phases by DFIs also typically involve substantial advisory services to support project development.

DFIs are increasingly supporting funds and fund-of-funds structures, with around USD 1 billion allocated to these finance facilities that use concessional capital to reduce investment risk and crowd in private capital through equity or senior debt at commercially viable returns. Over the past year, several of these funds (Table 5.1) have begun disbursing initial funding, mainly grants, to cover DEVEX expenditures. One specific financing structure is the development trust fund, in which one or more donors contribute capital that is held and managed by a DFI or multilateral body acting as trustee. Examples include the World Bank serving as trustee for the Climate Investment Fund and the Green Climate Fund, and the EIB acting as trustee for the Green Hydrogen Fund.

The USD 80 million Accelerate-to-Demonstrate (A2D) Facility, launched in 2023 by the United Kingdom and the United Nations Industrial Development Organization (UNIDO), supports smaller-scale, catalytic initiatives, including hydrogen projects. A2D provides grant funding for capital expenditure (CAPEX) and operating expenditure (OPEX), placing a strong emphasis on dissemination and replication through lighthouse projects. In April 2025, the Daures Green Hydrogen Village project in Namibia, which will produce ammonium sulphate fertiliser, was selected in the first funding round. A second call for proposals was launched in May 2025.

Table 5.1 Development finance institutions' contributions and disbursements to funds in emerging markets and developing economies targeting hydrogen-related investments

Fund	Description and projects financed
Climate Investor Three (CI3) feeder fund[72]	In 2025, Climate Fund Managers (jointly owned by the Dutch DFI FMO and South Africa´s Sanlam InfraWork) secured EUR 150 million for its CI3 fund targeting renewable hydrogen and energy transition projects in EMDEs. CI3 regional initiatives include the SDG Namibia One Fund and the SA - H2 Fund in South Africa (see below).
SDG Namibia One Fund	Co-developed with the Environmental Investment Fund of Namibia and Dutch DFI Invest International, with a funding target of USD 1 billion for Namibia's renewable hydrogen sector. In September 2024, the European Union announced a EUR 25 million investment under its Global Gateway strategy. • The fund is supporting the HyIron project for DRI production. • The fund provided EUR 23 million in DEVEX support for the Hyphen ammonia project and agreed to acquire a 24% equity stake.
SA-H2 Fund, South Africa	In 2025, the fund secured USD 37 million from South Africa's Public Investment Corporation, the Development Bank of Southern Africa and South Africa's Industrial Development Corporation (IDC), which had previously secured USD 80 million from the European Commission and Dutch DFI Invest International. • In June 2025, it allocated up to USD 20 million to Hive's Coega Green Ammonia Project, targeting 1 Mtpa ammonia production by 2029.
IDC-KfW Green Hydrogen Fund, South Africa - Germany	In November 2023, Germany's KfW and South Africa's IDC established the fund, which by 2025 had secured EUR 40 million in funding. • In June 2025, it approved its first grant to the Prieska project, which aims to produce 0.5 Mtpa of low-emissions ammonia by 2030.

[72] A feeder fund may invest directly into projects but may also invest in country-specific underlying funds.

<table>
<tr><th>Fund</th><th>Description and projects financed</th></tr>
<tr><td>PtX Development Fund, Germany</td><td>In November 2023, the German government and KfW established the PtX Development Fund to support large-scale low-emissions hydrogen projects in EMDEs, with EUR 270 million in funding.
In October 2024, the fund awarded a EUR 30 million grant to a 70 ktpa ammonia project in Egypt’s Suez Canal Economic Zone.
In February 2025, a second EUR 30 million grant was awarded to the Jorf Hydrogen Platform in Morocco, targeting 100 ktpa ammonia production by end-2026.</td></tr>
<tr><td>Climate Investment Fund (CIF)</td><td>CIF is a trust fund established in 2008 by the World Bank, the trustee, to finance climate mitigation and adaptation, pooling resources from multiple donors. Those supporting hydrogen come from the Clean Technology Fund.
The fund is supporting the Pecém Verde project in Brazil with USD 35 million (USD 33.5 million concessional loan, USD 1.5 million grant) for infrastructure to produce electrolytic hydrogen, under the Renewable Energy Integration programme.
In June 2025, CIF selected Brazil, Egypt, Mexico, Namibia, South Africa, Türkiye and Uzbekistan for the USD 1 billion Industry Decarbonization programme (targeting USD 12 in co-financing per USD 1 CIF funding); low-emissions hydrogen was identified as a priority in all selected countries.</td></tr>
<tr><td>Green Climate Fund (GCF)</td><td>GCF was established within the framework of the United Nations Framework Convention on Climate Change (UNFCCC) in 2010; the World Bank acts as a trustee, and is supporting some hydrogen-related projects:
In July 2025, GCF approved USD 50 million in concessional finance for ATOME’s Villeta project in Paraguay.</td></tr>
<tr><td>Green Hydrogen Fund</td><td>Established in 2021 with the EIB as trustee and in partnership with Germany’s GIZ, the fund serves as a platform for collaboration with other DFIs and private financial institutions. Replenished in December 2023, it has reached total funding of EUR 459 million. Since inception, it has provided technical assistance and advisory services, while investment grants are under discussion. The fund targets EMDEs listed by the OECD Development Assistance Committee’s list of recipients of official development assistance.</td></tr>
<tr><td>Copenhagen Infrastructure Growth Markets Fund II</td><td>In October 2024, the US International Development Finance Corporation committed USD 50 million in equity to the Copenhagen Infrastructure Growth Markets Fund II, which includes power-to-X projects in EMDEs.</td></tr>
</table>

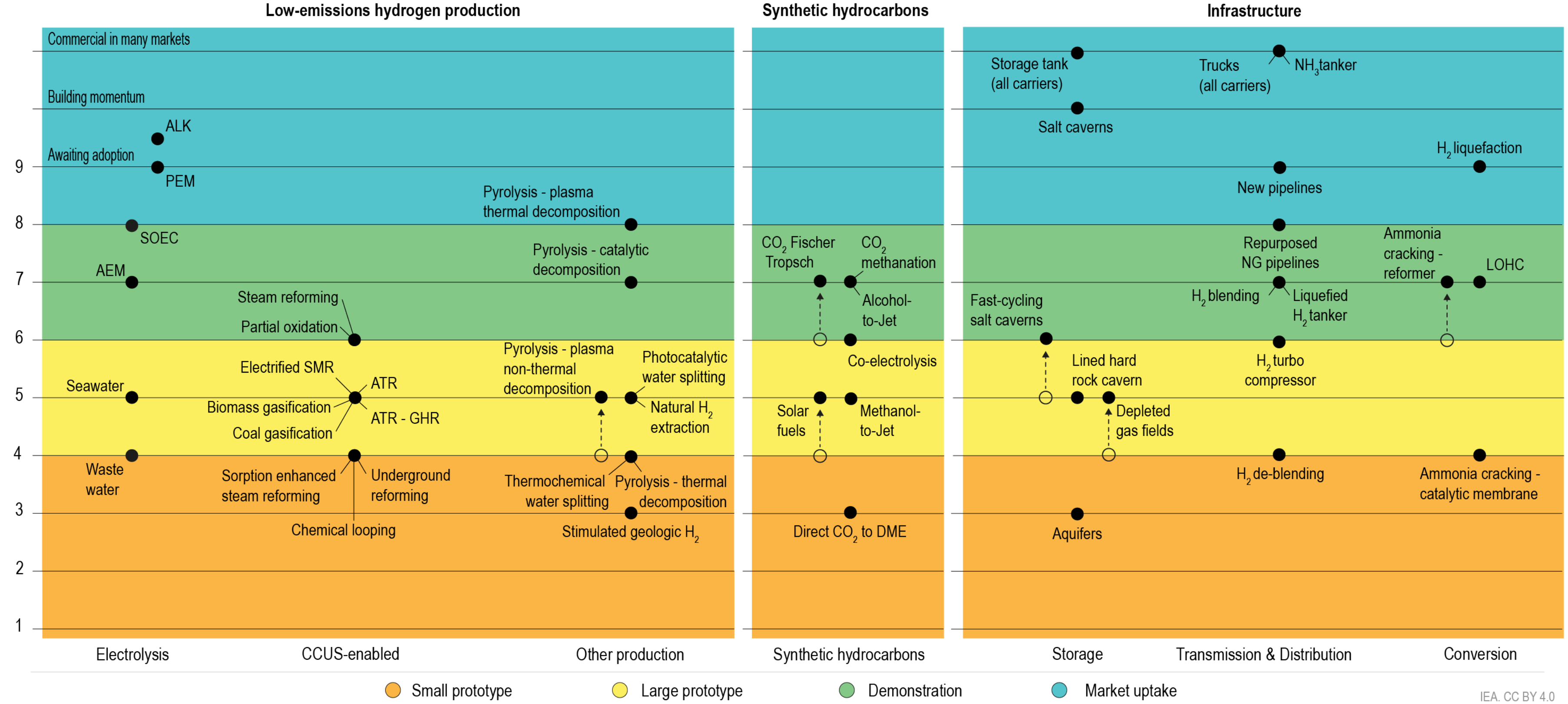
Innovation on hydrogen technologies

Hydrogen technologies have reached new milestones since GHR-24, achieving higher technology readiness levels (TRL), which indicates that long-standing innovation efforts are starting to bear fruit. This fifth edition of the GHR marks the highest number of upward shifts in TRLs to date, with 10 technologies advancing by at least one TRL (Figure 5.6-Figure 5.7).[73] Several others are positioned to progress further, contingent on the successful completion of ongoing demonstration projects. The share of technologies with a TRL below 4 is relatively small, indicating that most technologies not yet on the market have at least reached the pilot phase and are approaching first-of-a-kind demonstration or commercialisation. Notably, innovation activity is increasingly extending beyond supply-side technologies, with significant progress also observed in demand-side applications.

In April 2025, the IEA released its first State of Energy Innovation report, highlighting key innovation developments over the past year that have strengthened confidence in the accelerating pace of energy technology progress and associated cost reductions. Building on the same approach and grouping them into the same five innovation categories, this section provides a snapshot of selected hydrogen-related innovation milestones. These examples have been chosen to illustrate the breadth of technological and geographical progress across the hydrogen value chain. However, they represent only a small fraction of the advances under way, many of which are documented in greater detail in the IEA's ETP Clean Energy Technology Guide.

[73] In line with common usage of the TRL scale, the highest level is TRL 9. To provide additional insights into progress after reaching TRL 9, three adoption levels are used that are separated from the TRL assessment. The first of these is "awaiting adoption", which refers to technologies that have been successfully operated in a commercial environment and can be procured with appropriate technology guarantees, but for which there is no significant market for investment in new installations, whether supported by policy or not. The second level ("building momentum") refers to technologies that are being adopted in a limited number of countries or sectors and this adoption is set to grow further. The third level ("commercial in many markets") is reserved for technologies that are being readily adopted across multiple markets with few apparent barriers to reaching their full potential vis-a-vis competitors. Note that this represents an update compared to the classification shown in previous editions of GHR and the IEA ETP Clean Energy Technology Guide, from which TRL levels 10 and 11 are being phased out by the IEA.

Figure 5.6. Technology readiness levels of technologies for the production of low-emissions hydrogen and synthetic hydrocarbons, and infrastructure

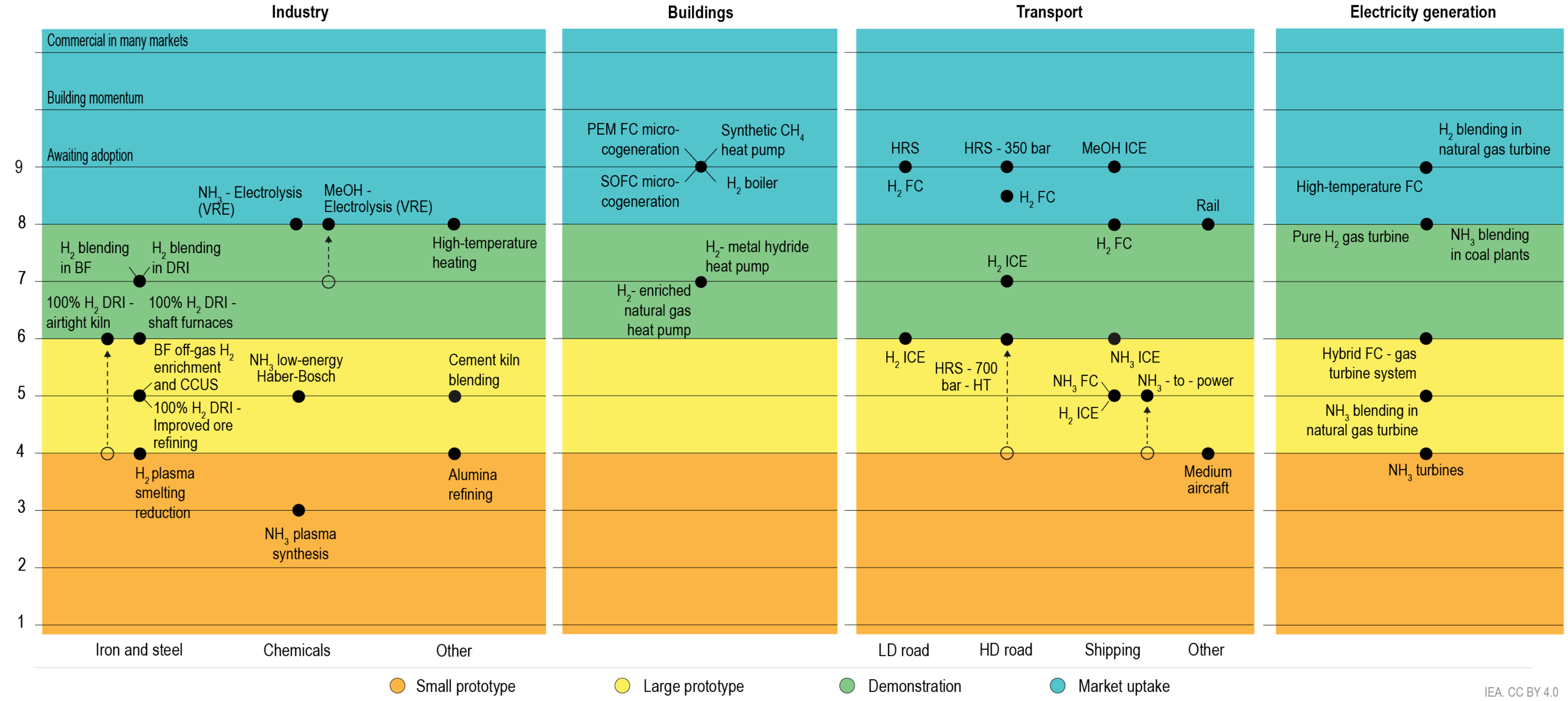


Notes: AEM = anion exchange membrane; ALK = alkaline; ATR = autothermal reformer; CCUS = carbon capture, utilisation and storage; CH_4 = methane; DME = dimethyl ether; GHR = gas heated reformer; LOHC = liquid organic hydrogen carrier; NG = natural gas; NH_3 = ammonia; PEM = proton exchange membrane; SMR = steam methane reformer; SOEC = solid oxide electrolyser cell. Biomass refers to both biomass and waste. Arrows show changes in technology readiness level between mid-2024 and mid-2025. For technologies in the CCUS category, the technology readiness level refers to the overall concept of coupling production technologies with CCUS and high CO_2 capture rates. Pipelines refer to onshore transmission pipelines. Storage in depleted gas fields and aquifers refers to pure hydrogen and not to blends. LOHC refers to hydrogenation and dehydrogenation of liquid organic hydrogen carrier.

Sources: IEA (2025), Clean Energy Technology Guide; IEA Hydrogen Technology Collaboration Programme.

Underground hydrogen storage has been validated by real-world testing, while synthetic fuel production via Fischer–Tropsch synthesis is advancing towards commercial scale.

Figure 5.7. Technology readiness levels of technologies for hydrogen end uses by sector



Notes: BF = blast furnace; CCUS = carbon capture, utilisation and storage; CH_4 = methane; DRI = direct reduced iron; FC = fuel cell; HRS = hydrogen refuelling station; HD = heavy-duty; HT = high throughput; ICE = internal combustion engine; LD = light-duty; MeOH = methanol; NH_3 = ammonia; PEM FC = proton exchange membrane fuel cell; SOFC = solid oxide fuel cell; VRE = variable renewable electricity. “Other” in industry includes all industrial sectors except methanol, ammonia and iron and steel production. “Other” in transport includes rail and aviation. Arrows show changes in technology readiness level between mid-2024 and mid-2025. Cogeneration refers to the combined production of heat and power.

Sources: IEA (2025), Clean Energy Technology Guide; IEA Hydrogen Technology Collaboration Programme.

End-use technologies are gaining ground, with several shipping technologies nearing readiness and advancing from the lab to the dockyard, and industrial projects under construction for delivering 100% hydrogen-based DRI within this decade.

Technology readiness levels climb, but the final step to market still lies ahead

Prominent advances in research and prototyping

TRL
9

Electrolysis/PEM

Iridium-free PEM electrolyser maintains performance over 15 000 hours in durability testing.

TRL
3

Subsurface H_2 production

First subsurface bio-stimulated hydrogen production trial in a legacy oilfield yields a 40% H_2 concentration in the resulting gas stream.

Note: Country flags represent headquarters of key firms and institutions, as well as project locations, if different.

Iridium-free PEM electrolyser maintains performance over 15 000 hours in durability testing. Electrolytic hydrogen production technologies are commercially available, with proton exchange membrane (PEM) and alkaline electrolysers representing the most mature designs. Ongoing innovation efforts are focused on reducing hydrogen production costs, particularly for PEM systems, by minimising the use of platinum group metals in catalysts to lower stack costs. In February 2025, US-based Calicat reported that its non-iridium PEM electrolyser catalyst sustained current densities above 2 A/cm² at a cell voltage of 2 V, a performance level typically requiring iridium. The catalyst demonstrated stable operation over 15 000 hours, addressing durability, a key limitation of non-iridium-based catalysts.

First subsurface bio-stimulated hydrogen production trial in a legacy oilfield yields a 40% H_2 concentration in the resulting gas stream. In June 2025, Gold H_2 completed a trial in California's San Joaquin Basin using its proprietary biotechnology to stimulate microbial activity in a depleted oil well. The process involves flooding the reservoir with microbes, turning the well into a fermentation reactor where residual hydrocarbons are broken down into hydrogen and CO_2. The resulting H_2-rich gas is extracted, while the CO_2 is either retained within the reservoir or sequestered through reinjection. As part of a broader category on subsurface technologies, this area has been further detailed in the ETP Clean

Energy Technology Guide in its April 2025 edition and includes both naturally occurring and artificially stimulated hydrogen[74]. Progress on natural hydrogen is summarised in Box 5.3.

Box 5.3 Natural hydrogen draws attention, but is still at an exploratory stage

Natural hydrogen has gained attention in recent years, with investor interest growing despite the early stage of surface and subsurface exploration methods. The only commercial production to date is at the Bourakebougou field in Mali (5 tpa, equivalent to 100 barrels of oil per year). Commercial development at scale before 2030 remains uncertain, due to the lack of established exploration tools and limited understanding of natural hydrogen's subsurface potential, particularly its generation, migration and, critically, its accumulation in commercially viable quantities. As a result, the cost of production remains highly uncertain and will depend on factors such as availability at scale, reservoir concentration, ease of extraction and the extent of gas clean-up required based on the composition of co-produced gases. Activity remains at the characterisation (surface prospecting, subsurface surveys) or appraisal stage, with some notable developments since GHR-24:

- **Europe**. In Spain, Helios Aragón is developing the Monzon-2 project, with appraisal drilling planned for H2 2025. In France, Storengy and 45-8 ENERGY has secured exploration licenses for nearly 1 000 km^2 in the south-west, while Mantle8 is developing AI tools to identify reservoirs in the Pyrenees. In Finland, 80 Mile reported significant surface hydrogen concentrations at legacy drill holes at its Hammaslahti project. In the United Kingdom, Desert Energy secured a 960 km^2 exploration licence.
- **North America**. The US Geological Survey released its first hydrogen prospectivity map identifying areas with high potential for exploration. HyTerra confirmed up to 96% hydrogen purity at its Nemaha Project in Kansas and began appraisal drilling, Top End Energy expanded its Kansas lease to 120 km^2, while Koloma and PureWave Hydrogen continued exploration. Desert Mountain Energy plans exploration in Arizona and New Mexico, and Primary Hydrogen in Colorado. In Canada, Max Power Mining announced 87% hydrogen purity in Saskatchewan, with 5 200 km^2 permitted for exploration and 23 000 km^2 under application. QMIC conducted a geochemical survey in Ontario-Quebec, began drilling and confirmed high hydrogen levels in

[74] Natural geologic hydrogen refers to hydrogen that accumulates in subsurface reservoirs over geological timescales, while stimulated geologic hydrogen involves accelerating these processes, such as through mineralisation, or applying *in situ* methods such as underground reforming or bio-stimulation.

Nova Scotia, where soil gas sampling started. In Quebec Squatex acquired 60 km^2, and in Ontario DiagnaMed holds exploration permits and Record Resources acquired land. In British Columbia, a satellite survey confirmed hydrogen-rich zones on 22 000 km^2, including Protium's lands, and Primary Hydrogen plans exploration, and in Newfoundland First Atlantic Nickel also plans exploration.

- **South America**. In Colombia, the National Hydrocarbons Agency confirmed subsoil hydrogen reserves in the Cordillera Oriental and Sinú-San Jacinto basins. Uruguay's ANCAP plans to launch a bidding round for geologic hydrogen exploration by end-2025. In Brazil, Petrobras is investing around USD 4 million in exploratory research, initiated in Bahia in 2023 and planned for expansion.
- **Asia Pacific**. In South Australia, Gold Hydrogen plans appraisal drilling at its Ramsay project by end-2025, D3 Energy has acquired exploration permits for nearly 6 000 km^2, Whitebark Energy will launch geochemistry surveys in mid-2025, and Thor Energy has announced positive results at its Hy-Range project and added 6 300 km^2 of exploration licences. In Tasmania, Devil Resources holds exploration licences for 6 000 km^2. New Zealand launched a public consultation on regulating hydrogen exploration. The Philippines launched the world's first natural hydrogen exploration auction in 2024, covering 2 300 km^2, after confirming 800 tpa H_2 at the Nagsasa seepage. In Indonesia's Sulawesi island, Pertamina Hulu Energi drilled three wells, with the Geological Agency confirming hydrogen at surface seepages.
- **Africa**. In Morocco, Getech and Sound Energy have created the JV HyMaroc and negotiate rights for exploration of geologic hydrogen.

The presence of helium in the same geological formations could present an opportunity to improve project economics through co-production. Hydrogen and helium frequently co-occur in subsurface reservoirs, and helium's high market value (USD 35–70/kg in 2025) has driven interest in joint exploration strategies. Several of the companies mentioned above, such as Devil Resources, HyTerra, H_2Au, 45-8 ENERGY and HyMaroc, are pursuing integrated hydrogen–helium exploration efforts.

First-of-a-kind pilot and demo achievements

TRL
5

Electrolysis/Seawater

First 100-kW pilot for direct seawater electrolysis completed and MW-scale project begins trial operation.

TRL
4 → 5

Methane pyrolysis/Plasma

Pilot plant producing 1 tpa each of hydrogen and graphene commissioned using low-temperature methane pyrolysis via microwave plasma.

TRL
6

Shipping/Ammonia engine

Maiden voyage completed by world's first vessel powered solely by ammonia using a 200-kW combustion engine.

TRL
4 → 5

Shipping/Ammonia-to-power

Maiden voyage completed by first vessels using onboard ammonia cracking to hydrogen for fuel cell propulsion.

TRL
5 → 6

Underground storage/Salt cavern

Hydrogen cycling successfully validated in a salt cavern over 100 cycles at different rates.

TRL
4 → 5

Underground storage/ Depleted gas field

Field test in a depleted gas reservoir successfully stores 100% H_2 and recovers it at over 98% purity after several months.

TRL
6 → 7

Infrastructure/Ammonia cracking - reformer

The largest ammonia cracking plant at 15 ktpa starts operation with plans to scale up.

TRL
4 → 6

Iron and steel/Airtight kiln

First DRI produced in rotary kilns using iron ore fines and 100% hydrogen, without pelletisation.

TRL
6 → 7

Synthetic fuels/ CO_2 FT synthesis

2.5 ktpa synthetic fuel plant using hydrogen and biogenic CO_2 begins successful operations.

TRL
4 → 5

Synthetic fuels/ Solar fuels

Diesel produced from the first industrial-scale solar plant converting biogas to syngas at high temperatures, followed by Fischer–Tropsch synthesis.

First 100 kW pilot for direct seawater electrolysis completed and MW-scale project begins trial operation. In December 2024, Sinopec completed a 100 kW pilot project at its Qingdao refinery, China, producing hydrogen directly from seawater using chlorine-resistant electrodes. In the same month, China National

Offshore Oil Corporation commenced trial operations of the world´s first megawatt-scale seawater electrolyser, successfully completing a test run.

Pilot plant producing 1 tpa each of hydrogen and graphene commissioned using low-temperature methane pyrolysis via microwave plasma. In January 2025, ADNOC and Baker Hughes commissioned a 1 tpa hydrogen and graphene pilot plant at a gas facility in Abu Dhabi, using Levidian's LOOP technology based on low-temperature, low-pressure microwave plasma. Levidian also agreed with Dana Gas to deploy a 1.5 tpa plant in the United Arab Emirates by end-2025, using flared gas. In Canada, Aurora Hydrogen completed construction of a microwave methane pyrolysis demonstration plant.

Hydrogen cycling successfully validated in a salt cavern over 100 cycles at different rates. In May 2025, the HyPSTER project announced the completion of 4 months of hydrogen storage testing in salt caverns in France, involving approximately 100 injection–withdrawal cycles under varying conditions of pressure and cycling speed, successfully validating its feasibility. Further projects are underway, and in August 2024, Uniper commissioned the HPC Krummhörn project in Germany to test hydrogen storage in a 3 000 m³ salt cavern (1.8 GWh).

Field test in a depleted gas reservoir successfully stores 100% H_2 and recovers it at high purity after several months. In May 2025, the Underground Sun Storage 2030 project completed the first field test of 100% hydrogen storage in a depleted porous sandstone gas reservoir in Austria, storing 500 000 m³ and extracting it at high purity in two cycles. Building on this work, the EUH2STARS project, launched in 2024, aims to validate full-scale hydrogen storage in depleted gas fields by 2030 through demonstrations in Austria, Hungary, the Netherlands, and Spain.

The largest ammonia cracking plant, at 15 ktpa NH_3, starts operation with plans to scale up. Ammonia cracking technologies based on reforming processes are progressing toward larger-scale deployment. Topsoe's technology has been in commercial operation since 1993 plant in Arroyito, Argentina, in two 2.4 ktpd ammonia cracking lines, and its H_2Retake solution builds on this. In September 2024, Air Liquide began operating a 15 ktpa ammonia pilot plant in the Port of Antwerp, Belgium – the largest ammonia cracker (besides Arroyito) – and was awarded EUR 110 million to, among other things, scale up a project with a 30 ktpa H_2 (~170 ktpa ammonia) capacity under the ENHANCE initiative. In May 2025, Uniper and thyssenkrupp Uhde announced a partnership to develop a 28 tpd of ammonia demonstration plant at Gelsenkirchen-Scholven, Germany, for late 2026, linked to future import plans in Wilhelmshaven. KBR's cracking technology was selected in 2023 for a 10 tpd H_2 plant for Korean ISU Chemical, due in 2026. It was later awarded contracts for a 200 tpd H_2 and a 214 tpd H_2 plant, both by Korean firm Hanwha.

2.5 ktpa synthetic fuel plant using hydrogen and biogenic CO_2 begins successful operations. In June 2025, INERATEC's 2.5 ktpa plant in Germany began commercial operations, producing synthetic fuels and wax from by-product hydrogen from a chlor-alkali plant and biogenic CO_2 via Fischer–Tropsch synthesis. In May 2025, Infinium began construction of Project Roadrunner in the United States, the largest low-emissions hydrogen-based synthetic fuels plant currently under construction, with an expected capacity of 23 ktpa of synthetic aviation and other fuels. Smaller projects using electrified heat sources also progressed. These included the FrontFuel SynFuels project in Denmark (12 kg/h CO_2), which started operations in November 2024 using Topsoe's electrified reverse water gas shift reactor,[75] and the 2.5 ktpa of synthetic fuels Leuna plant in Germany, currently under construction and targeting synthetic kerosene and diesel production from 2027, also using Topsoe's technology.

Diesel produced from the first industrial-scale solar plant converting biogas to syngas at high temperatures, followed by Fischer–Tropsch synthesis. Synhelion's DAWN plant in Germany, operational since mid-2024, uses solar thermal (heliostats and receiver) or PV with electric heating to generate >1 100 °C process heat for biogas-to-syngas conversion, followed by traditional Fischer–Tropsch synthesis, with integrated heat storage to enable continuous operation. By Q2 2025, the plant was running at close to nameplate capacity, with solar fuel used in a Harley-Davidson motorcycle, an Audi car and a steamboat. Further innovation progress on technologies that aim to directly convert solar energy into hydrogen, chemicals or fuels is summarised in Box 5.4.

Maiden voyage completed by world's first vessel powered solely by ammonia using a 200-kW combustion engine. In June 2025, the Anhui became the world's first vessel to complete a maiden voyage powered solely by ammonia using a 200 kW combustion engine, sailing on Chaohu Lake, China, with a 50-tonne load. In March 2025, the Sakigake tugboat in Tokyo Bay reached 95% ammonia co-firing at full load in a 3-month trial by NYK and IHI. Pre-commercial testing for larger vessels is advancing: MAN achieved 100% ammonia operation in a two-stroke engine in Denmark and plans to deliver an ammonia-ready version by end-2025 using 5% pilot fuel[76]; MITSUI began testing a MAN 60-bore prototype in Japan for a 200 000 deadweight tonnes (DWT) bulk carrier; and WinGD completed full-load trials of its 52-bore low-speed engine in Switzerland, with multi-cylinder testing planned in Shanghai. Wärtsilä has offered a modular four-stroke dual-fuel ammonia engine since 2023, reporting an 18% emissions improvement. In May 2025, MAN launched the NH_3 Spark – FutureFlex project to develop a four-stroke engine able to run on 100% ammonia without pilot fuel.

Maiden voyage completed by first vessels using onboard ammonia cracking to hydrogen for fuel cell propulsion. In mid-2024, H2SITE validated ammonia cracking combined with hydrogen fuel cell propulsion aboard a supply ship operating in the Gulf of Biscay, and Amogy's retrofitted tugboat completed its

[75] The reactor converts CO_2 and H_2 into syngas – a mixture of CO and H_2 -- used as feedstock for the downstream Fischer–Tropsch synthesis to produce fuels and chemicals.

[76] Pilot fuel refers to a small quantity of easily ignitable liquid fuel—typically diesel or marine fuel oil—used in engines running on gaseous fuels to initiate and stabilise combustion. In the case of ammonia, which has a high autoignition temperature and slow flame propagation, pilot fuel is currently required to ensure reliable ignition and steady operation.

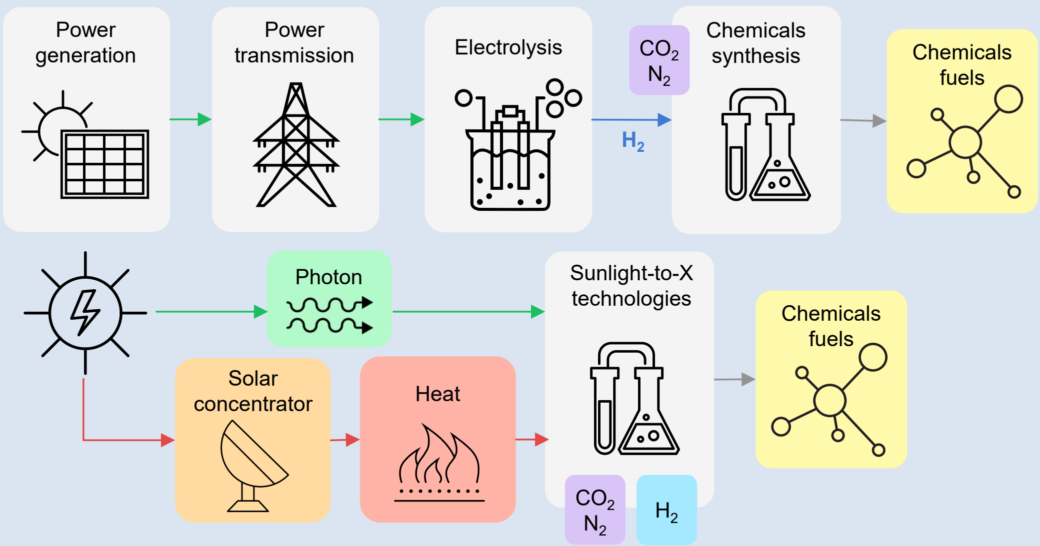
maiden voyage in the United States using the NH_3 Kraken system. In June 2025, Pherousa received Approval in Principle from the American Bureau of Shipping for an onboard ammonia cracking system integrated with PEM fuel cells, to be deployed on a 64 000 DWT Ultramax bulk carrier.

First DRI produced in rotary kilns using iron ore fines and 100% H_2, without pelletisation. In March 2025, HyIron's Oshivela plant in Namibia produced its first DRI using 100% hydrogen in rotary kilns, processing magnetically separated iron ore fines directly without pelletisation or sintering. The plant has 15 ktpa of DRI capacity and targets scale-up to 2 Mtpa by 2030.

Box 5.4 Turning sunbeams directly into chemicals and fuels

Solar water-splitting technologies use energy from sunlight to turn simple molecules, like water, CO_2 or nitrogen, directly into useful fuels and chemicals, such as hydrogen, ammonia, or synthetic hydrocarbons. Because these processes can yield a wide range of final products, the term "Sunlight-to-X" is sometimes used to refer to these technologies, with "X" representing the diverse array of possible outputs. Unlike conventional processes that first convert sunlight into electricity, these technologies skip this step by using special materials that absorb solar radiation and trigger chemical reactions directly.

Illustrative example of conventional versus direct solar technologies



Notes: Among direct solar pathways, the most advanced are those using sunlight photons, namely integrated PV-electrolysis systems, photoelectrochemical cells and photocatalytic approaches, which harness sunlight photons to drive chemical reactions directly. Solar thermochemical routes depend on high-temperature heat or a combination of heat and light. Solar-driven biological conversion technologies, where microorganisms use sunlight to produce fuels or chemicals, are not represented in this figure.

While solar water-splitting technologies remain at a demonstration stage with relatively low TRLs, their successful development could unlock valuable benefits:

- **Decentralisation and modularity**: these technologies can operate independently of the electricity grid, enabling onsite production of fuels and chemicals. Their plug-and-play design allows installations to be sized according to local resource availability and demand.
- **Product selectivity and flexibility**: the catalyst determines the end product, enabling high selectivity and targeted synthesis of specific chemicals or fuels, and allowing multi-product reactors tailored to user needs.
- **Potential for lower land use**: laboratory-scale solar water-splitting systems have achieved solar-to-hydrogen (STH) efficiencies above 20%, comparable to or exceeding the combined efficiency of the best commercial PV panels today (around 24%) and electrolysers (typically ~55-65%), which would imply a lower round-trip solar-to-electricity-to-hydrogen efficiency. However, at the demonstration scale, STH efficiencies are still lower for solar water-splitting technologies, and the start-up SunHydrogen, for example, has reported record efficiencies of 9% for a 0.12 m^2 module. If the technologies improve their STH efficiency, which measures how effectively solar energy falling on a surface is converted into chemical energy, higher values will translate into more fuel produced per square metre of sunlight, reducing the area of land potentially required for solar-driven chemical and fuel production.

Scaling Sunlight-to-X technologies requires overcoming several barriers, particularly the development of stable, scalable photoelectrodes and reactor components that avoid the use of critical raw materials. A central challenge lies in the absence of standardised metrics and testing protocols, which hampers reproducibility and makes it difficult to compare results across laboratories and technology types, an issue also observed in other technologies such as perovskite solar cells or electrolysers, where inconsistent definitions have complicated performance benchmarking. International initiatives, such as the 2024 European Innovation Council's Pathfinder Challenge on Solar-to-X devices, are now working to define common performance indicators, procedural reporting requirements and test protocols. These efforts, through co-ordinated international collaboration and broad stakeholder involvement, aim to support fair comparison and accelerate innovation.

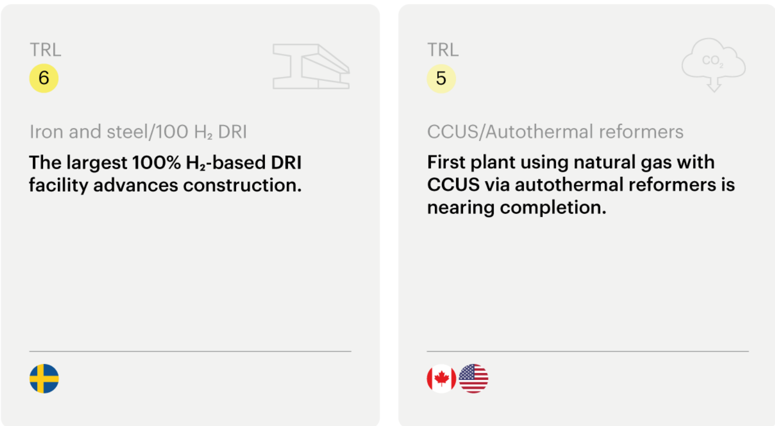
A growing number of start-ups are actively working to bring these technologies closer to pilot- and demonstration-scale deployment:

- Sparc Hydrogen (Australia): A photocatalytic water-splitting pilot plant using concentrated solar energy began commissioning in mid-2025, aiming to test multiple reactor configurations and photocatalysts.

- SunHydrogen (United States): Launched front-end engineering for a >25 m² photoelectrochemical (PEC) hydrogen pilot plant, following smaller-scale demonstrations. The facility will integrate ~15 PEC panels, each with 1.92 m² active area, targeting operation in late 2025.
- REDEEM (Austria): Advancing lab-scale photoreactor development, aiming to boost hydrogen production efficiency by 30% using plasmonic photocatalysts and to reduce reliance on titanium and palladium.
- SolHyd (Belgium): Developing integrated 500–1000 W solar-hydrogen modules, with initial deployment in a Namibian project combining the systems with hydrogen cookstoves for rural use.
- CSIRO's beam-down solar reactor (Australia): CSIRO demonstrated a pilot in which heliostats (sun-tracking mirrors) concentrate sunlight that is redirected into a reactor containing doped ceria (metal oxide particles) as a catalyst, where high temperatures drive water-splitting.
- NewHydrogen (United States): Stock uplisting to the OTCQB Venture Market in 2025 to expand investor access and increase its liquidity while advancing its ThermoLoop technology, a heat-driven hydrogen production technology.

Source: Information in this box is based on inputs from Mission Innovation (MI)'s Sunlight-to-X Innovation Community.

Announced commitments to go to the next level



First plant using natural gas with CCUS via autothermal reformers is nearing completion. Autothermal reforming (ATR) enables high CO_2 capture rates by producing a single concentrated CO_2 stream. A production plant is currently under construction in the United States and is expected to begin operations in 2026. A second ATR-CCUS project in Canada has reached FID, but has been delayed until 2028.

The largest 100% H_2-based DRI facility is under construction. The world's largest 100% hydrogen-based DRI facility, Stegra's 2.5 Mtpa plant in Sweden, has been under construction since 2023. Electrolyser installation began in late 2024, and as of June 2025, the electrolyser buildings are nearing completion and preparing to receive compressors. Stegra and LKAB have agreed to begin test deliveries by the end of 2026.

New products and processes hitting the market

TRL

Transport

New open access research facility for the development and testing of MW fuel cell propulsion systems for different transport applications.

TRL 4 → 6

Road transport/HRS

700-bar hydrogen refuelling stations capable of refuelling heavy-duty trucks in 10 minutes became commercially available.

TRL 8

Shipping/Hydrogen fuel cell

Shipyards begin building the first hydrogen-powered cruise ships and bulk carriers.

TRL 5

Ammonia/Low-energy Haber-Bosch

500 tpa order for the first industrial-scale low-temperature, low-pressure ammonia synthesis plant.

TRL 7 → 8

Methanol

A large-scale CO_2-to-methanol plant using electrolytic hydrogen starts successful operations.

500 tpa order for a the first industrial-scale low-temperature, low-pressure ammonia synthesis plant. Tsubame has operated a 20 tpa ammonia pilot plant in Japan since 2019, using electride catalysts, which have lower energy requirements, to enable low-temperature, low-pressure Haber–Bosch synthesis. In September 2024, the company received a commercial order for the first industrial-scale 500 tpa plant in Japan – a 25-fold scale-up – due in 2026, and in April 2025 signed a letter of intent with Atvos for a 20 ktpa plant in Brazil, targeting construction in 2026. Other companies are also advancing in low-energy ammonia synthesis. In February 2025, NitroVolt scaled its lithium-mediated process in Denmark from gramme-per-day to kilogramme-per-day levels, with planned deployment in plants of up to a few tonnes per day.

A large-scale CO_2-to-methanol plant using electrolytic hydrogen starts successful operations. Icelandic company Carbon Recycling International became the first to produce methanol at industrial scale from CO_2 in 2012. Two plants in China – Shunli in Anyang (operating since 2022) and Sailboat in Jiangsu (2023) – produce over 100 ktpa of methanol from CO_2,using by-product hydrogen from industrial processes. The largest plant using electrolytic hydrogen is European Energy's Kassø Power-to-X facility in Denmark, which began operations in February 2025 with a capacity of 42 ktpa of synthetic methanol.

Shipyards begin building the first hydrogen-powered cruise ships and bulk carriers. In April 2025, Fincantieri began construction in Italy of the world's first two hydrogen-powered cruise ships for Viking, featuring liquefied hydrogen and fuel cell propulsion, with delivery expected from late 2026. In June 2025, Norwegian company Møre Sjø ordered the first hydrogen-powered bulk carriers, 4 000 DWT vessels using compressed hydrogen in a hybrid fuel cell–battery system, designed by Naval Dynamics and scheduled for delivery by 2027 from Gelibolu Shipyard in Türkiye. In July 2025, LH2 Shipping received USD 24 million in funding from ENOVA to build a liquefied hydrogen-powered bulker with 2 MW fuel cells and a 1 MW battery.

700-bar hydrogen refuelling stations capable of refuelling heavy-duty trucks in 10 minutes became commercially available. In January 2025, Cavendish announced plans to commercialise its 700-bar hydrogen refuelling stations capable of refuelling heavy-duty trucks in 10 minutes in 2025.

Enhancements to R&D facilities and test sites

TRL

Transport

New open access research facility for the development and testing of MW fuel cell propulsion systems for different transport applications.

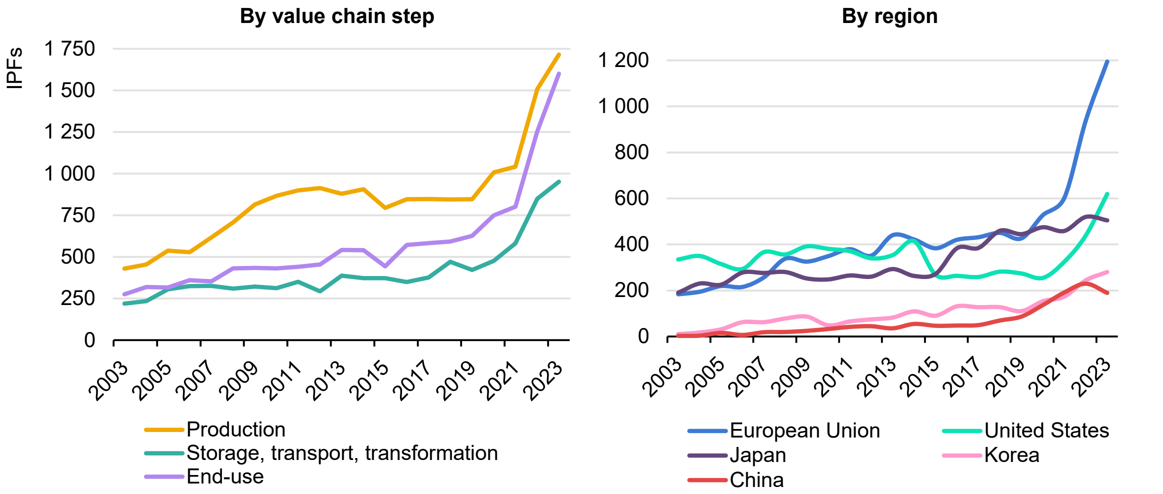
New open access research facility for the development and testing of megawatt fuel cell propulsion systems for different transport applications. In October 2024, the German Aerospace Center (DLR) opened the BALIS test centre to develop and test hydrogen fuel cell propulsion systems with megawatt-scale outputs. At launch, the centre announced that the facility was fully booked for the next 3 years by research projects involving industrial partners, including start-ups.

Patenting of hydrogen technologies keeps on rising

The latest data on hydrogen patenting globally, measured by international patent families (IPFs), show a nearly 20% increase in applications globally in 2023,[77] with high growth rates for technologies across the value chain, but particularly in end-use technologies. While this marks a slowdown compared to 2022, when patenting rose by nearly 50%, the 5-year trend remains robust following a period of relative stagnation in the 2010s. Hydrogen patenting in 2023 was more than double the level recorded 5 years earlier. Although patenting is typically a lagging indicator of innovation activity, the recent acceleration suggests positive momentum that could translate into technological improvements in the near future.

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

Figure 5.8. Hydrogen technology patenting trends by step in the value chain and main regions, 2003-2023



Notes: IPFs = international patent families. The calculations are based on the country of the IPF applicants, using fractional counting in the case of co-applications. For more information, see IEA & EPO (2023), Hydrogen patents for a clean energy future.

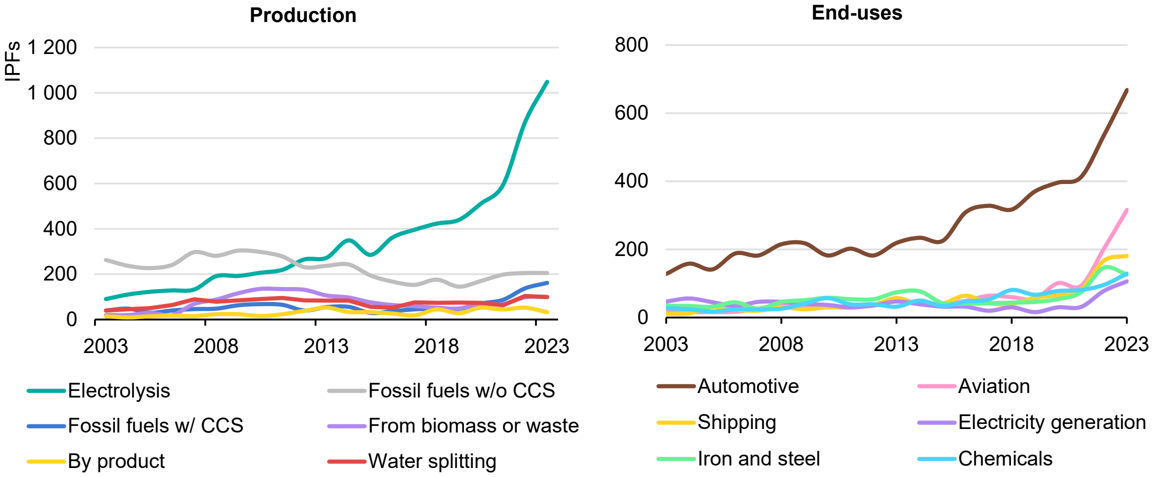
Source: IEA analysis based on data from the European Patent Office.

Global hydrogen patenting rose nearly 20% in 2023 and has more than doubled over the past 5 years, driven by rising activity across the full value chain.

Patenting growth in 2023 varied significantly across regions. The number of patent applications increased notably in the European Union and the United States, with the latter overtaking Japan in total filings. In contrast, y-o-y patenting activity declined in both Japan and China. Looking at the 5-year trend, however, patenting more than doubled in China, the United States and Korea, and nearly tripled in the European Union, while remaining relatively flat in Japan, despite it being the single largest source of hydrogen patents in 2019.

Year-on-year growth in hydrogen production patenting in 2023 was driven by electrolysis, which accounted for two-thirds of all production-related filings. However, this growth varied across electrolysis technologies. Patenting activity declined for alkaline electrolysers, a more mature technology, and for AEM electrolysers, while it increased significantly for PEM and SOEC, each representing around 40% of electrolysis-related filings in 2023. Annual trends can fluctuate, so multi-year patterns provide a clearer picture. Over the past 5 years, PEM patenting grew 2.5 times, alkaline patenting tripled, SOEC nearly quadrupled, and AEM increased almost fivefold. Patenting for hydrogen production from fossil fuels with CCS also grew strongly, more than tripling over 5 years, though it represented only 10% of total production-related filings in 2023.

Figure 5.9. Hydrogen production and end-use technology patenting trends, 2003-2023



Notes: CCS = carbon capture and storage; IPFs = international patent families.
Source: IEA analysis based on data from the European Patent Office.

Automotive remains the lead sector for hydrogen end-use innovation, but emerging applications are catching up fast, with patents more than tripling in the past 5 years.

Patenting in hydrogen end-use applications has increased considerably in recent years. While the automotive sector continues to dominate, its share declined from 60% of end-use patents 5 years ago to less than 45% in 2023. The largest growth in 2023 was observed in the aviation sector, with more than 55% growth, accounting for 20% of end-use patenting. The chemical sector also saw notable growth, with a 34% y-o-y increase overall, and nearly 60% growth specifically in ammonia production technologies, despite more moderate figures over the past 5 years compared to other sectors. Patenting in shipping rose modestly in 2023, while filings related to iron and steel technologies declined; however, in both cases, activity has approximately tripled over the past 5 years, highlighting the importance of assessing multi-year trends rather than annual fluctuations alone.

Chapter 6. Policies

Highlights

- Announced public funding for low-emissions hydrogen decreased by nearly two-thirds compared to the Global Hydrogen Review 2024 (GHR-24), to a cumulative USD 38 billion, but a larger share of funds is now making its way to specific projects. Several programmes in the European Union, India, Japan and United Kingdom have progressed to the second phase or beyond, with new calls building on learning from the first phase.
- Almost 90% of the public funding comes from advanced economies; other policy instruments like land allocation, tax incentives and reduced administrative procedures remain more common among emerging markets. The supply side still receives more support, equal to USD 1.5 for every USD 1 targeting demand.
- Publication of new hydrogen strategies slowed down, with five new strategies since GHR-24. Some strategies were updated, such as in France, which reduced its electrolyser target to 4.5 GW by 2030 (from 6.5 GW), whereas Spain tripled its target to 12 GW by 2030. Chile and the European Union missed their electrolyser targets for 2024 and 2025, respectively.
- Progress was made on the demand side, but it is still trailing supply. 112 demand-side policies have moved forward since GHR-24, frequently in the form of grants and sectoral quotas. Legislated policies could trigger demand for nearly 6 Mtpa of low-emissions hydrogen by 2030, while government demand targets add up to 9.5 Mtpa; production targets are in the range of 27-33 Mtpa.
- On the supply side, 114 policies have advanced since GHR-24, with a total public funding of nearly USD 21 billion. Almost three-quarters of the policies are from advanced economies. In a change from previous years, specific calls are being opened and projects selected across Europe, India, and at a global level with H2Global. The same is true for tax incentives, which are now fully defined in Australia, Canada, Finland, Morocco and the United States.
- Certification is progressing, with the ISO standard on track to be fully in place by 2025/2026. This can serve as a guideline for countries that are still developing their schemes. India launched its certification scheme, and the European Union has now recognised schemes and certification bodies that can certify renewable hydrogen and ensure compliance with EU mandates.
- Infrastructure regulation has gained clarity, with several European countries defining the methodology for tariff-setting and cost recovery during early periods of low utilisation. Solutions include intertemporal cost allocation and subsidies.

The analysis in this chapter is complemented by the new online Hydrogen Tracker available on the IEA website, which contains more than 1 000 hydrogen policies worldwide announced or implemented since 2020.

Overview of funding

Public funding for hydrogen technologies is now showing signs of maturation. Total announced funding has decreased by nearly two-thirds compared to what was reported in GHR-24 from almost USD 100 billion to USD 38 billion, but a lot of the funding has moved from announcements to allocation to specific projects. For reference, investment in hydrogen production was USD 4.3 billion in 2024 (see Chapter 5). In large part, the difference with last year is explained by multi-year programmes that were announced in 2024. These included the Important Projects of Common European Interest (IPCEI) in the European Union, Carbon Contracts for Difference (CCfD) for industrial use in Germany, and the contracts for difference (CfD) for hydrogen production in Japan, which together represented nearly USD 35 billion of last year's total. In all those cases, no new funding has been announced in 2025, but the programmes have progressed. In Germany, results from the first round of the CCfD scheme were announced, and its second round was approved by the European Commission in March 2025, Japan and France both opened the first round of their CfD schemes, and Finland, Italy and Spain have allocated IPCEI funds to specific projects.[78]

Almost 90% of the USD 38 billion of funding under policies announced or updated since GHR-24 is from advanced economies (Figure 6.1). This is a reflection of funding in the form of grants, auctions and CfDs being more common in advanced economies, whereas emerging economies tend to use other instruments, such as tax incentives, fixed premiums or simplified administrative procedures. Most of the funding from emerging economies is from India, through the Strategic Interventions for Green Hydrogen Transition (SIGHT) programme targeted to electrolyser manufacturing and ammonia production.

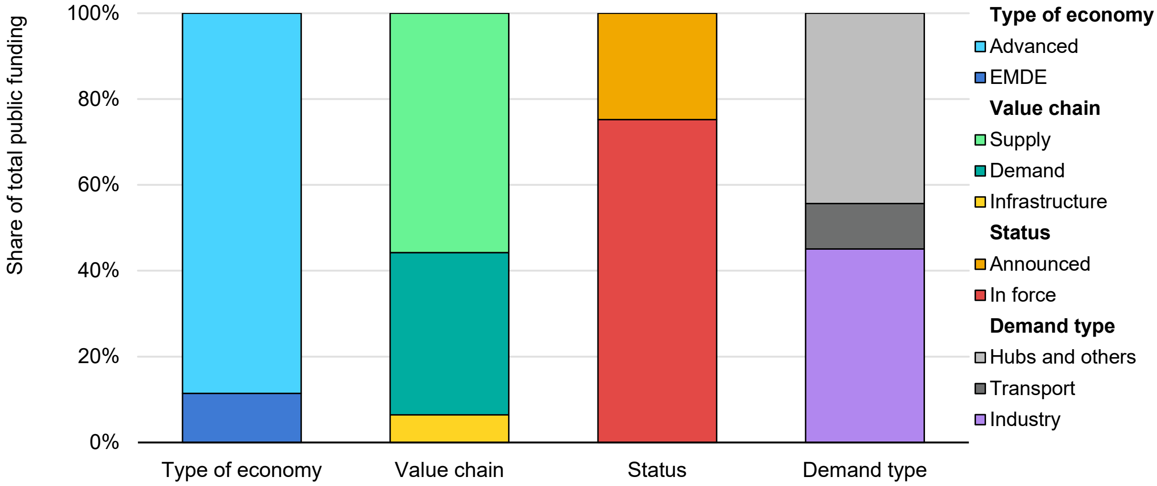
The ratio between funding targeted to supply and demand remains similar to last year, at about USD 1.5 of support to supply for every dollar in support for demand. Of the funding targeting demand, nearly half is for the industrial sector (including current hydrogen uses), for which the largest contribution is from the second round of the CCfD programme in Germany (USD 5.5 billion). Another 35% of the demand funding is for hubs, like those in Korea and the Netherlands,[79] or cross-cutting aspects, like the National Wealth Fund in the United Kingdom. Almost USD 3.5 billion targets both supply and demand, like H2Global or incentives for

[78] Recent analysis suggests that 69% of the IPCEI projects have signed grant agreements and 21% have reached final investment decision (FID).

[79] For the Netherlands, the fund is still under consultation and has not yet opened for proposals.

manufacturing of electrolysis and fuel cells in Poland and the United States. Nearly USD 2.5 billion was destined for infrastructure, including loans for the hydrogen networks in Denmark and Italy.

Figure 6.1. Share of public funding linked to hydrogen-related policies by location, status and use, 2024-2025



IEA. CC BY 4.0.

Notes: EMDE = emerging markets and developing economies. Not all the policies can be converted into a monetary value. Some of this funding is multi-year. Numbers include both specific calls and tenders that have been awarded and announcements of future funding programmes (which lack detail in many cases).

Almost 55% of the public funding announced since GHR-24 is directed towards the supply side and 75% is linked to legislation that is now in force.

The share of funding from policies that have been implemented is now almost 75%, in comparison to just over one-third in GHR-24. Some of the largest policies are the Hydrogen Production Tax Incentive in Australia, approved by the Parliament in early 2025 (USD 4.3 billion),[80] a loan guarantee for ammonia production in the United States (USD 1.56 billion) and a 20-year fixed premium in Denmark (USD 1.9 billion). Total funding comes from 50 policies that were announced or progressed to the next stage of funding allocation, with most of the funding coming from European policies.

Strategies and targets

Since GHR-24, Bolivia, Italy, Lao People's Democratic Republic (Lao PDR), Paraguay and Switzerland have published a hydrogen strategy, bringing the total number of countries with a hydrogen strategy to 65, of which 29 are emerging economies.

[80] Funding for tax incentives is taken from government budgets where available.

Bolivia published a strategy focused on the actions needed to achieve a vision for 2050, and a roadmap that assesses the cost, potential and challenges. The documents focus on renewable hydrogen, due to declining production of natural gas and the potential for exports. The roadmap estimates a domestic hydrogen demand of 1.6 Mtpa for 2050, driven by hydrogen blending of up to 30% in 2050 in natural gas and methanol blending in the transport sector, with the latter seen as a way to reduce oil imports. On the supply side, some of the defined targets include 150 ktpa of renewable hydrogen production by 2030 (of which 85 ktpa are to be exported), 1.35 Mtpa by 2040 and 4.15 Mtpa by 2050 (with 2.65 Mtpa destined for export). Production cost targets are USD 1.8/kg by 2030 and USD 1/kg by 2050. The cumulative investment needs to achieve these production levels are USD 26.1-34.4 billion by 2050.

Italy's strategy confirms the 2030 targets from the National Energy and Climate Plan of 3 GW of electrolysis, 137 ktpa of demand from transport, 115 ktpa for industry, and at least 70% of demand met by domestic production. Total investment needs for 2050 are EUR 29-57 billion. The strategy estimates 15-30 GW of electrolysis by 2050, requiring cumulative investments of EUR 8-16 billion for electrolysis alone, creating 4 700 to 9 000 jobs. Investment needs for the demand side are EUR 16-33 billion, with the bulk of this going to the transport sector. The strategy includes three scenarios with a hydrogen demand of between 2.2 Mtpa and 4.2 Mtpa in 2050, with nearly 45-55% used for aviation and trucks. Most of the difference between scenarios relates to hydrogen demand for industrial heat and trucks. As a point of reference, current hydrogen demand in Italy is about 525 ktpa.

Paraguay's strategy prioritises renewable hydrogen**,** with targets for 2030 including 1 GW of electrolysis, 900 ktpa of fertiliser production and 80-100% substitution of current gas-based hydrogen. The strategy adopts a gradual approach, with fertilisers as an immediate hydrogen application and other uses dependent on market and technology development. It notes that more than half of current fertiliser imports (1.2-1.4 Mtpa) could be replaced by fertilisers using 450 ktpa of renewable ammonia. The strategy defines 55 actions across 19 areas under six pillars, including a regulation for additionality and temporal correlation of renewable electricity, the creation of demand hubs, the possible use of fiscal incentives, and the development of a certification scheme.

Switzerland prioritises renewable hydrogen in its strategy, estimating a demand of 24-55 ktpa by 2030 and 110-305 ktpa by 2050, and import by pipeline to start in the mid-2030s. The strategy defines measures with a timeline for completion across 9 areas, including a certification scheme to be in place by 2025, financial support for production from 2025 to 2030, an exemption from grid fees, and an exemption from CO_2 tax for hydrogen used as a fuel.

For an overview of Lao PDR's new strategy, see Chapter 7.

France updated its strategy in April 2025. The 2030 target for electrolysis deployment was revised to up to 4.5 GW (from 6.5 GW) and the 2035 target revised to 8 GW (from 10 GW). One reason for this downward revision was slower-than-expected deployment, both domestically and globally. The strategy highlights the importance of hydrogen production from electrolysis using low-emissions electricity from the grid as a pathway to emissions reduction. The low-emissions hydrogen demand estimated for 2030 is 320-520 ktpa (in comparison to a current demand of up to 400 ktpa). A support mechanism of EUR 4 billion to support the deployment of 1 GW of electrolysis was confirmed. The first tender of this programme was launched in December 2024.

In **Germany**, the coalition agreement of the new government recognises the importance of hydrogen for the national energy transition. This supports a technology-neutral approach for production in the ramp-up phase, with a view to increasing the share of renewable hydrogen over time, including through imports. Some of the action areas include the accelerated expansion of the hydrogen network, expansion of import infrastructure and support for electrolytic hydrogen production. In aviation, Germany's quota for synthetic fuels will be aligned with the EU standard. The coalition plans to launch a legislative package for the use of carbon capture and storage in industry and for power generation from gas. Separately, the government is considering support for nuclear, including nuclear fusion, and has signalled greater alignment with France on nuclear power. However, the first budget proposal from the new government cuts 2026-2032 funding for the national hydrogen strategy by nearly two-thirds compared to the budget proposed by the previous government. The new budget proposal also cuts the 2026-2046 funding for industrial decarbonisation by more than 90%. The draft budget of the Climate and Transformation Fund proposes EUR 15.5 billion to support the national hydrogen ramp-up from 2025 to 2029. Overall, Germany is carrying out comprehensive internal monitoring of its energy policy to assess the status of the energy transition, and the results will form the basis for a realignment of political priorities, including for the hydrogen sector.

Cyprus[81,82] published a draft strategy for public consultation until March 2025. This showcases two scenarios for hydrogen development to 2050 with milestones in 2030. The scenarios are based on fixed technology penetrations by sector. Total investment needs are EUR 2.4 billion by 2030 and EUR 6.8 billion by 2050 for the

[81] The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Türkiye recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Türkiye shall preserve its position concerning the "Cyprus issue".
[82] The Republic of Cyprus is recognised by all members of the United Nations with the exception of Türkiye. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

ambitious scenario, while the conservative scenario has an investment of EUR 170 million by 2050. The strategy does not define specific targets or actions.

There has also been a revision of renewable hydrogen targets since GHR-24. **Spain** tripled its electrolyser target to 2030 (compared to its original strategy) to 12 GW. Spain is already making progress towards its target by supporting a total of 3.7 GW of electrolysis capacity with national funding.

At the sub-national level, the state of Telangana in **India** set a target of 418 ktpa of renewable hydrogen by 2030, which would correspond to about 8% of the national target.

With regards to targets from previous strategies, **Chile** looks likely to miss its aspirational target of 5 GW of electrolysers operating and under development by 2025, and the **European Union** has not achieved its vision of installing at least 6 GW of electrolysers by 2024. See Chapter 3 for more information on the project pipeline.

Demand creation

A total of 112 different policies targeting demand creation have been announced or have moved forward since the publication of GHR-24, with 33 of these targeting both supply and demand. In total, 15 are from emerging economies. Nearly two-thirds of the policies were in the form of grants and sectoral quotas.

In the **European Union**, the Renewable Energy Directive (RED) entered into force in November 2023 with a deadline of May 2025 for transposition into national legislation. RED defines quotas[83] for renewable hydrogen and its derivatives (called renewable fuels of non-biological origin [RFNBO]) for industry and transport, which sends a clear demand signal for renewable hydrogen. These quotas are binding for member states, but there is flexibility on the approaches taken to achieve the quotas. This means countries can use a range of instruments, potentially leading to a heterogenous landscape across the European Union. By May 2025, only Denmark had adopted laws addressing all aspects of RED, and in July 2025, the European Commission opened infringement procedures against the other 26 member states, giving them two months to reply and complete the transposition. Moreover, the diverse approaches being proposed to meet these targets have raised concerns among industry stakeholders regarding potential market fragmentation within the bloc. For transport, only the Czech Republic, Denmark, Finland, Lithuania and Romania, which represent less than 15% of the European Union’s hydrogen demand, had transposed quotas into national law.

[83] Quotas equal a 42% share of demand by 2030 and 60% by 2035 for industry. In transport, it requires a 5.5% share for advanced biofuels and RFNBO, with a minimum of 1% from RFNBO only. RFNBO have a multiplier of 2 for transport.

- The **Czech Republic** introduced a combined quota for biofuels and RFNBO, starting from 1.25% in 2026 and increasing to 5.5% in 2030, combined with a minimum quota of 1% of RFNBO in 2030. Non-compliance penalties are equivalent to nearly USD 10/kg H_2.

- **Denmark** opted for a combination of a GHG reduction target of 5.2% by 2025-2027, 6% by 2028-2029 and 7% by 2030 (in comparison to the fossil fuel reference of 94 g CO_2/MJ) and a combined biofuels and RFNBO target of 5.1% by 2030, with a minimum of 0.9% of RFNBO. Alternative fuels used in aviation count towards the target, but aviation and maritime are exempted from the obligation.

- In **Finland**, a 1.5% RFNBO quota for road transport is introduced from 2028, increasing to 4% in 2030, with a maximum of 1% to be satisfied with the hydrogen used in refineries, and a non-compliance penalty equivalent to USD 7.3/kg H_2. RFNBO could also contribute to Finland's broader 10% quota for renewable fuels by 2030, but this contribution might be limited by their cost-competitiveness in comparison to biofuels.

- **Romania** introduced a 5% RFNBO target by 2030, imposed at the company level for fuel suppliers, with a non-compliance penalty equivalent to USD 6.5/kg H_2. For the years prior to 2030, there is a combined target for RFNBO and renewable electricity, which increases from 0.5% of the energy content of all transport fuels in 2025 to 4.5% in 2029.

- **Lithuania** finalised the transposition in mid-July, with targets of 1% RFNBO for overall transport by 2030 and 1.2% for shipping. Multipliers of 2 for road transport and 3 for aviation and shipping are considered. The penalty for non-compliance is EUR 0.06/MJ, equivalent to EUR 7.2/kg H_2**.**

Other EU member states are considering how to transpose the legislation. **Germany** proposed RFNBO quotas as part of a broader bill revising the GHG reduction targets. Proposed RFNBO quotas start at 0.1% in 2026, rising to 1.5% by 2030 and 12% by 2040. Non-compliance penalties are EUR 17 000/t for aviation and EUR 8.4/kg for other sectors. The draft bill also extends GHG quota compliance to the aviation sector. The bill is under consultation with industry associations and is expected to be in place by January 2026.

Belgium is considering the introduction of RFNBO quotas for road transport, starting at 1% in 2028, increasing to 2.5% in 2029 and 4% in 2030. A multiplier of 2 would be used for RFNBO (i.e. effective 2030 target is 2%) and up to 85% of the target could be met with hydrogen used in refineries. **Ireland** is planning to expand its current Renewable Transport Fuel Obligation to include RFNBO. The proposed

2030 quotas (2.5% in 2030) are higher than in RED, to consider the multiplier of 4 for RFNBO. In the **Netherlands**, the transposition proposal includes a GHG emissions reduction target of 1.07% for road transport to be met with RFNBO. Any hydrogen used in refineries will count directly towards the targets,[84] which might benefit projects evaluating renewable hydrogen for refining. In **Poland**, RFNBO quotas are expected to be introduced by a draft act amending the Biocomponents and Liquid Biofuels Act and the Renewable Energy Sources Act. Changes are expected to be enacted by Q2 2026.

Several member states are discussing alternative measures for transposing the industrial target set by RED. Only the **Czech Republic** and **Romania** have adopted relevant legislation to date, while other countries have made progress in their proposals. **Finland** is considering using the same quotas as defined in RED and additionally introducing financial incentives. This proposal is part of a broader review of the national energy and climate strategy, which will require public consultation and then some months to turn into legislation. The **Netherlands** is considering using quotas reaching 4% in 2030 and 9.9% in 2035, and aiming to meet the rest of the RED targets with a mix of demand- and supply-side incentives (with nearly EUR 2.8 billion announced so far in 2025). Certificate-trading for compliance will be permitted, and 60% of the hydrogen demand for ammonia production will be exempted, taking advantage of the recognition in RED that downstream units (i.e. urea production) might be dependent on existing units with steam reforming. Compliance would fall upon the operators of industrial facilities. Finalisation of the legislation is expected in early 2026 with a revision every 2 years thereafter. Elsewhere, **Spain** held a public consultation from July to September 2024 on transposition of the targets, though results are still pending.

In **China**, the main policy introduced is the Implementation Plan for Accelerating the Application of Clean and Low-Carbon Hydrogen in the Industrial Field. Although it does not set quantitative targets, the plan defines 30 actions across metals, green methanol, ammonia, fuel cell electric vehicles, ships, aviation, rail and industrial microgrids to encourage and promote the use of "clean" and "low-carbon hydrogen".[85] By 2027, the steel, ammonia synthesis, methanol synthesis and refining sectors should achieve large-scale deployment of low-carbon hydrogen. Targets also include more demonstration projects in the transport and power sectors, aiming to create a series of innovative low-carbon hydrogen use cases in shipping, aviation, rail transit, power generation and energy storage by 2027.

[84] Earlier iterations introduced a cap in the contribution that hydrogen used in refineries could have towards the target, considering that it is not directly consumed as a transport fuel, but the final decision was not to have such a correction factor.
[85] See Explanatory notes annex regarding the use of the terms "clean" and "low-carbon" hydrogen in this report.

In **India**, tenders for refining have been opened for more than 40 ktpa of renewable hydrogen, with offtake agreements for up to 25 years at 8 different sites owned by state-owned enterprises. Part of the support under the SIGHT programme targets ammonia, indirectly promoting the uptake of low-emissions ammonia in current industrial uses. India also has some smaller R&D calls to demonstrate hydrogen use for steel production, both in existing blast furnaces and use up to 100% in shaft furnaces for direct iron reduction. Another call is for demonstration in decentralised applications like cooking, heating and off-grid applications.

In addition to the policies mentioned above, several others targeting the industrial sector have been further developed since GHR-24. **Austria** introduced a EUR 3 billion programme providing capital expenditure (CAPEX) and operating expenditure (OPEX) support in the form of grants. The first round opened in February 2025 for EUR 300 million, with a maximum incentive of EUR 600/t CO_2, stipulating that projects must be implemented by 2031. **Finland** introduced a tax credit programme for industrial processes[86] with up to EUR 2.3 billion of funding. The tax credits start in 2028 for 19 years and cover up to 60% of the eligible investment cost for renewable hydrogen projects. Finland also has a complementary EUR 400 million grant programme for industrial decarbonisation. Projects should achieve at least 40% GHG reduction or 20% reduction in energy consumption and must be completed within 36 months of receiving the funding. **France** opened the first call of the DECARB IND 25 programme, which provides grants for up to EUR 30 million to individual projects. The programme specifically targets fuel shift and carbon capture, utilisation and storage (CCUS), and will have another two rounds in 2025 and 2026 (subject to budget availability).

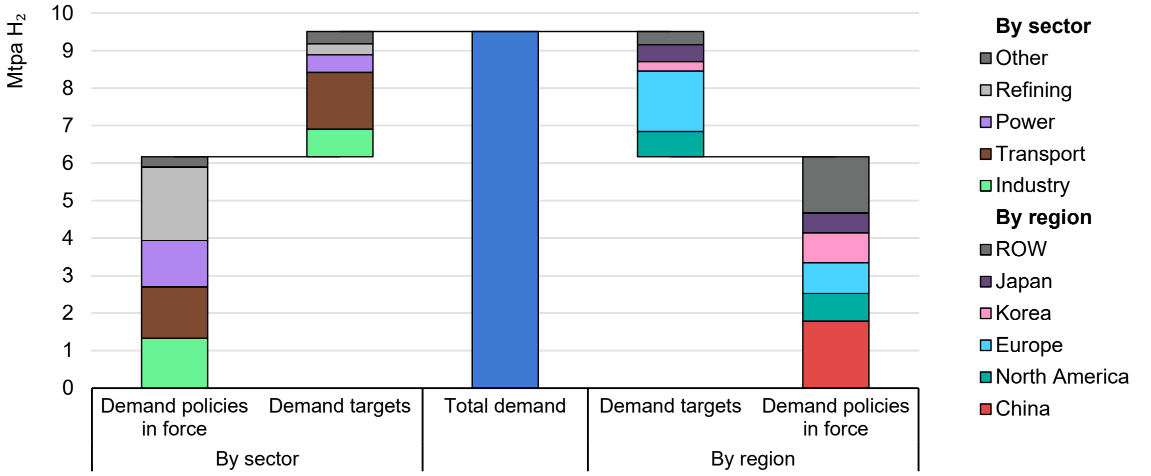
Offtake certainty is one of the key factors improving project bankability. Currently, there are two policies that can provide this certainty: H2Global, and the model in India. For H2Global, an auction lot for renewable ammonia provides a guaranteed offtake for 6 years (for 40 ktpa). In India, the government offers 10-year purchase agreements for ammonia. In both cases, a (government-backed) intermediary is used to either open a separate call for demand or to co-ordinate different players on the demand side to guarantee offtake. In both cases, the scheme covers the price and volume risks (for a period that is shorter than the project lifetime).

In the **United States**, funding for hydrogen projects was cut as part of a review of the Office of Clean Energy Demonstrations at the Department of Energy (DoE), which led to the cancellation of 24 projects with a total funding of USD 3.7 billion. Three hydrogen projects applying for a total funding of USD 632 million were among the projects cut; they include an e-methanol plant from Orsted (USD 100 million), a project on ethylene from CO_2 and "low-carbon"[87] hydrogen

[86] Clean technology manufacturing and hydrogen production are also covered.
[87] See Explanatory notes annex regarding the use of the term "low-carbon" hydrogen in this report.

(USD 200 million), and on hydrogen use in industrial fired equipment (USD 332 million). The latter project might continue with private funding given that testing had already started in December 2024.

Figure 6.2. Potential annual demand for low-emissions hydrogen created by policies in force and government targets by region and sector, 2030



Notes: ROW = Rest of world. Values reflect all announced policies at time of writing. Values are exclusively for demand, noting that targets for supply are about three times higher than the demand targets. “Demand policies in force” represents the maximum of the capacity from committed projects in the pipeline and the legislated policies.

Demand policies that are already in force add up to nearly 6 Mtpa by 2030, well below the 9.5 Mtpa envisaged by government targets.

Hubs

Hubs that bring together several users in the same location can provide an alternative to trigger initial demand. Demand can be aggregated, and even a small offtake from each user can result in enough demand to create economies of scale for hydrogen production and infrastructure.

Spain allocated EUR 1.3 billion to seven projects for hydrogen valleys with a cumulative electrolyser capacity of 2.3 GW, including three projects for synthetic fuel production. These projects were selected from 16 that had applied for funding for a total of 4 GW of (cumulative) electrolyser capacity.

Italy has allocated EUR 500 million from its Recovery and Resilience Plan to hubs. So far, 52 hubs have been supported. Even though these are for relatively small electrolysers (1-5 MW), they can be useful to build experience across different project configurations.

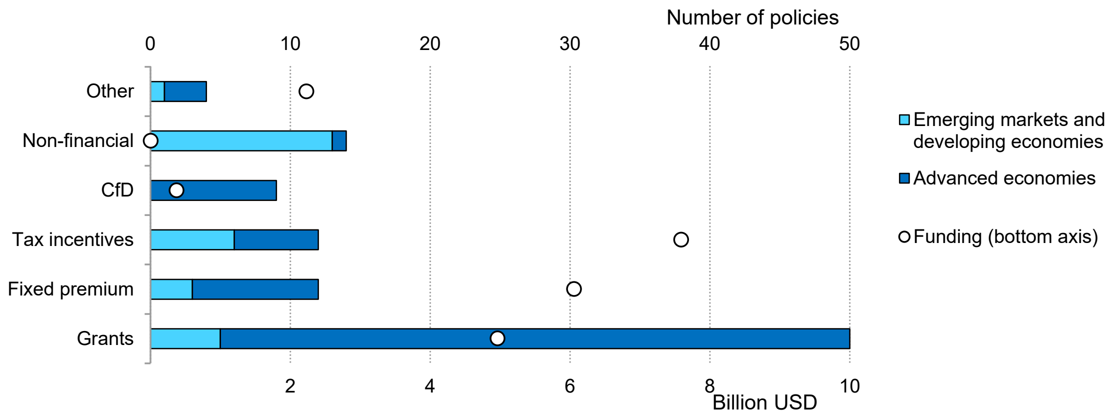
In the **United States**, seven hydrogen hubs had been selected as winners in October 2023 and the funding for the first phase (feasibility studies) was awarded to the last hubs in January 2025. The DoE is reviewing the pipeline of projects, including these hubs, and the review is expected by the end of the summer. In the meantime, feasibility studies are ongoing.

Among emerging economies, **Brazil** pre-selected 12 proposals under the Climate Investment Fund (CIF)'s Industry Decarbonization programme, through which up to USD 250 million can be made available to fund up to 50% of the project costs. Five of those projects were selected to make the investment plan proposal to the World Bank with a potential implementation by 2035.

Mitigation of investment risks

A total of 114 policies mitigating investment risks on the supply side have been announced or have advanced since GHR-24. The total public funding in these policies amounts to USD 21 billion (Figure 6.3). Of these policies, 31 are in emerging economies, and 33 cover both supply and demand. Grants were the most-used policy instrument, with 50 policies and USD 5 billion of funding. Advanced economies were behind 45 of these policies. Fixed premiums (12 policies) and tax incentives (12) were also widely used, with a combined funding of nearly USD 14 billion. Some of the most notable policies are discussed in the following sections.

Figure 6.3. Funding and number of policies for mitigating investment risks based on developments since the Global Hydrogen Review 2024



Notes: CfD = contracts for difference. Only policies that have been announced or made progress since GHR-24 are included. Funding is not included if it was announced before 2024.

A total of 114 policies for mitigating investment risks have been announced or have made progress since GHR-24, with a total funding of USD 21 billion.

As in GHR-24, emerging economies mostly used non-financial incentives such as tax exemptions, simplified administrative processes and land allocation. India is an exception, with financial support provided through the SIGHT programme.

There are also ten policies related to electrolyser manufacturing. Only three of these, in the Czech Republic and Finland, are new, whereas the rest were updated to either clarify the rules or issue specific calls.

Grants

Nearly 80% of the grant funding to have been announced or updated since GHR-24 comes from Europe. **Spain** has provided EUR 1.7 billion of funding since GHR-24, including EUR 1.2 billion for seven hydrogen valleys, as outlined above, and EUR 524 million from the Hy2Use IPCEI for five projects with a combined electrolyser capacity of 425 MW. **Italy** allocated EUR 994 million from the Hy2Infra IPCEI to specific companies. The **Netherlands** awarded EUR 700 million (out of EUR 3.2 billion) requested to eleven companies for the construction of more than 600 MW of electrolysis. The incentives combined CAPEX support (up to 80% of the investment cost) with OPEX support (up to EUR 9/kg) for up to 10 years. In December 2024, **Poland** launched a EUR 636 million tender to support the development of 315 MW of electrolysis (as well as refuelling stations and fuel cell electric vehicles). The incentive is as CAPEX up to EUR 2 000/kW. Six winners were announced in June 2025. The European Commission approved EUR 350 million to produce synthetic fuels in **Germany**. The funds are expected to support 30 ktpa of production from 2028 using CO_2 from a cement plant. Other grants for electrolysis included EUR 120 million in the **Czech Republic**, EUR 112 million for a 50-MW electrolyser in **Greece** and EUR 15 million for a 10-MW electrolyser in a refinery in **Croatia**.

Six hydrogen-related projects signed grant agreements under the EU Innovation Fund call from 2023. The pre-selection had returned eight hydrogen-related projects, but four of those withdrew their applications. An additional two hydrogen-related projects[88] were taken from the reserve list.

Among developing economies, the state of Andhra Pradesh in **India** awarded a grant to a 1 Mtpa ammonia plant. The incentive is capped at INR 18.5 billion (Indian rupees) (USD 215 million) for up to 25% of the total CAPEX, and will be provided over a 5-year period after commissioning. In **Chile**, six projects selected following a call for expressions of interest for electrolyser projects signed contracts with CORFO back in 2021.[89] The contracts for these projects – which have a total capacity of nearly 400 MW of electrolysis – included the condition that they would start operations in 2025, but this now seems unlikely.

Since GHR-24, there was limited explicit grant policy support for hydrogen production from fossil fuels with CCUS: One of those was the CCUS Cluster

[88] For a 330 tpa renewable hydrogen plant in Luxembourg and 210 ktpa CCS-based hydrogen plant in the Netherlands.
[89] Full details of the call and projects expressing interest can be downloaded from the CORFO (Chilean economic development agency) website.

Sequencing Process in the **United Kingdom**. This is part of the country's broader goal of developing four CCUS clusters by 2030. Under Track 1, two clusters (HyNet and East Coast) had been selected in October 2021, and a commercial agreement with industry was reached in October 2024. The total funding available is up to GBP 21.7 billion[90] (USD 27.7 billion) over 25 years, and the clusters are also expected to attract GBP 8 billion (USD 10.2 billion) in private investment. This funding will support both infrastructure and capture projects. Funding enabled the financial close of projects in the East Coast cluster in December 2024, with construction expected to start in mid-2025. For the HyNet cluster, projects were notified about the delivery assessment outcomes in September 2024 and a list of projects selected for negotiations is expected in Q2 2025. For Track-2, two clusters (Acorn and Viking) were selected in July 2023, and in June 2025 GBP 200 million (USD 261 million) of funding was announced to support project development of the Acorn project.

With regards to infrastructure, the results from the first call of the Connecting Europe Facility programme were announced in January 2025. The total funding for hydrogen was EUR 250 million across 21 projects, which will be used for development (feasibility and front-end engineering design [FEED]) studies. Projects include hydrogen pipelines, storage, import terminals and electrolysers. This is part of a broader incentive of over EUR 1.2 billion for 41 projects across all technologies. The second call, with EUR 600 million of funding, was launched in April 2025, with results expected in 2026.

Contracts for difference

In **Japan**, the Hydrogen Society Promotion Act and the revised JOGMEC[91] Act came into effect on October 2024. The CfD defined by these acts provides financial support to suppliers and targets sectors where emissions are hard to abate, like industry and transport.[92] The reference price will be based on conventional fuel prices for new hydrogen applications and on historical fossil-based hydrogen prices for existing applications. A call for applications was open from November 2024 to March 2025, and the first projects should begin operations by 2030.

In the **United Kingdom**, the Hydrogen Allocation Rounds (HAR) moved forward. The first round for up to 250 MW of electrolysis was launched in July 2022 and 11 winning projects with a cumulative electrolyser capacity of 125 MW were announced in December 2023. By July 2025, ten of those projects had signed 15-year contracts with the government. The second round had a targeted electrolysis

[90] Only a share of the total funding might be available as grants.
[91] The Japan Organization for Metals and Energy Security (JOGMEC) is a government entity established in 2004 by the merger of the former National Oil Corporation and the Metal Mining Agency.
[92] Proposals including the power sector could be considered if that is not the only targeted application.

capacity of 875 MW. The round was launched in December 2023 and 27 shortlisted projects with a total of 765 MW of electrolysis were announced in April 2025. The next steps include due diligence (which took five months for the first round), followed by refinement of the proposals and negotiation. The next two HAR rounds are expected be launched in 2026 and 2028.

France opened the first round of its CfD scheme in December 2024, targeting 200 MW of electrolysis capacity, to be powered by renewable or low-emissions electricity. The tender was open to up to 12 projects of 5-100 MW. Subsidies can be OPEX only or a mix of CAPEX and OPEX. OPEX support is for 15 years, capped at EUR 4/kg as a function of gas, electricity and CO_2 prices, with the possibility of a clawback mechanism. Only industrial hydrogen uses are eligible. Requirements include securing at least 60% offtake, reaching final investment decision (FID) within 30 months of being awarded the subsidy contract, and starting operations within 60 months. The completion guarantee is 8% of the subsidy requested and the price criteria has at least 70% weight in the evaluation. The tender opportunity closed in March 2025. Further tenders are expected for 250 MW in 2025 and 550 MW in 2026, for a total of 1 GW by 2026 and EUR 4 billion.

In **Portugal**, results of the first two-way CfD auction for renewable hydrogen were announced in February 2025 for a total volume of 120 GWh/yr (3.6 ktpa) which represents about 3% of the current national hydrogen demand. Eight hydrogen projects were selected, with nearly all the volume auctioned at the maximum price of EUR 127/MWh (equivalent to about USD 4.7/kg). Producers will sell the hydrogen to Transgas (national gas supplier) and will receive a guarantee of origin certificate. The scheme has a total budget of EUR 140 million, with contracts awarded for 10 years.

Other competitive bidding schemes

The second tender of **H2Global** was launched in February 2025 with five lots – four of which are regional (Africa, Asia, North America, and South America and Oceania) and one is global. Each regional lot has a budget of EUR 484 million, while the global lot has a budget of EUR 567 million, adding up to total budget of EUR 2.5 billion, with a potential to increase to EUR 3 billion pending approval of the German federal budget. EUR 2.2 billion was provided by Germany and EUR 300 million by the Netherlands. The regional lots are “product open” (which means any hydrogen derivative is possible as a final product) and the delivery point is Germany. The global lot is “vector open” (which means different carriers are used, but hydrogen needs to be delivered) and the delivery points are Germany and the Netherlands. The bid period will run until March 2026, and delivery is expected between 2028 and 2036 with purchase agreements for 10 years. Australia and Canada announced further funding for H2Global of around

USD 220 million each. By August 2025, H2Global had not yet announced the results of the methanol lot launched in December 2022. A public consultation for the joint auction between Germany and Canada was launched in July 2025.

The second auction of the **European Hydrogen Bank** was launched in December 2024 with a budget of EUR 1.2 billion. The call attracted 61 bids for a total funding requested of more than EUR 4.8 billion, with an electrolyser capacity of 6.3 GW and an annual production of more than 730 ktpa. The incentive provides OPEX support in the form of a fixed premium for up to 10 years. Some differences with the first round include a completion guarantee of 8% (in comparison to 4%), the stipulation that a maximum of 25% of stack capacity can be sourced from China, a dedicated budget (EUR 200 million) for a specific sector (maritime), and a lower ceiling price (EUR 4/kg in comparison to EUR 4.5/kg). Winners were announced in May 2025. The awarded funding was nearly EUR 1 billion across 15 projects adding up to 220 ktpa of production. Winning bids were EUR 0.2-0.6/kg for the general round and EUR 0.5-1.9/kg for the maritime sector. Selected projects will need to reach FID within 2.5 years of signing the agreements and to start operations within 5 years. Grant agreements are expected to be signed by October 2025. The same auction process can be used by Austria, Lithuania and Spain to award additional national funding of EUR 813 million using the "Auction-as-a-service" mechanism. Spain approved bids worth EUR 377 million. For Lithuania, there were no projects bidding; Austria is still to announce the projects supported through the mechanism. In August 2025, four projects (from both rounds) with a total electrolyser capacity of 1.3 GW, withdrew from the scheme due to regulatory uncertainty, lack of firm offtake and infrastructure delays. The terms and conditions for the third auction were published in July 2025 and the tender for up to EUR 1.1 billion is expected to be launched by the end of 2025.

India's SIGHT programme has a total budget of INR 175 billion (USD 2.1 billion) for 2025-2030, of which INR 131 billion (USD 1.6 billion) is targeted at the production of hydrogen and ammonia. The funding is distributed across two modes: Mode 1 is for a 3-year period and is open to exports, and Mode 2 has specific volumes of hydrogen and ammonia, to be used only for domestic consumption, with contracts to be signed for 10 years. In the second round of Mode 1, INR 22.4 billion (USD 260 million) was awarded to nine companies for a total of 450 ktpa of renewable ammonia with an average incentive equivalent to USD 0.2/kg H_2, well below the USD 0.6/kg cap. For Mode 2, the first round for demand was opened in June 2024 and 13 projects were pre-selected in March 2025, with a total offtake capacity of 724 ktpa of ammonia (in comparison to a targeted capacity of 750 ktpa). For supply, the 13 tenders were awarded in August 2025 at a price of USD 580-750 t H_2.

Tax incentives

Among advanced economies, **Australia**'s Hydrogen Production Tax Incentive was legislated in February 2025. This incentive provides OPEX support of AUD 2/kg (Australian dollars) (USD 1.3/kg), for a maximum of 10 years, for hydrogen produced between July 2027 and June 2040, with a maximum GHG emission intensity of 0.6 kg CO_2/kg H_2. The cost of industry support payments through to June 2034 is estimated at AUD 6.7 billion (USD 4.4 billion). The incentive is demand driven, meaning the total support provided will depend on market uptake. **Canada** plans to extend its Clean Hydrogen Investment Tax Credit to cover methane pyrolysis, and EverWind Fuels made a submission to claim the credit for a renewable ammonia project. The credit rate covers between 15% and 40% of the eligible investment costs based on carbon intensity, and the investment tax credit is expected to provide CAD 17.7 billion (Canadian dollars) (USD 13 billion) from the national budget from 2023 to 2035. The **United States** published the final rules of the Clean Hydrogen Production Tax Credit (45V) (Box 6.1) and the Clean Fuels Production Credit (45Z) in January 2025. A new legislation passed in July 2025 changed the sunset clause of the 45V credit, now requiring construction to start before the end of 2027 (the original requirement was for operation to start before the end of 2032), extended the 45Z credit to 2029 (from 2027) and increased the credit value for enhanced oil recovery in 45Q.[93] In Europe, **Finland** received approval for a EUR 2.3 billion scheme from the European Commission. Under this scheme, tax credits can cover up to 60% of the eligible investment costs starting in 2028 for up to 19 years, and also cover electrolyser manufacturing. Funds should be allocated in 2025.

Among emerging economies, **Morocco** selected five consortia developing six projects in southern regions (which have high renewable energy capacities) to benefit from the "Moroccan Offer". This includes tax benefits such as exemption from import duties and VAT on goods and equipment, as well as customs advantages. The selected projects aim to produce ammonia, synthetic fuel and low-emissions steel. **Mauritania** passed legislation introducing tax incentives for hydrogen production, which include exemptions from VAT and export tax, reduction of import customs duties from 4% to 2% and lower corporate tax. The legislation also creates the Mauritanian Agency for Green Hydrogen to regulate development activities. The government aims to issue traceability guarantees or guarantees of origin to attest to the renewable nature of the hydrogen produced. **Brazil** approved a 3 GW hydrogen and ammonia project in the Export Processing Zone of Parnaíba. Projects operating in this area can benefit from tax incentives including income tax and up to 75% reduction in corporate income tax.

[93] Also extending the credits that required permanent storage to be applicable to CO_2 use or enhanced oil recovery (USD 85/t for industrial and power facilities and USD 180/t for direct air capture).

Box 6.1 Final rules of the Clean Hydrogen Production Tax Credit (45V IRA) in the United States

The 45V incentive is a tax credit applicable for a period of 10 years for projects that start construction before the end of 2027. The amount of the incentive is related to the emissions intensity of the hydrogen produced, with the maximum incentive (USD 3.2/kg H_2) given to projects that meet a threshold of 0.45 kg CO_2/kg H_2 (well-to-gate). The incentive is divided by five if the facility does not meet certain labour conditions (i.e. if prevailing wage and apprenticeship requirements are not met, the maximum incentive is USD 0.637/kg). The incentive can be stacked with state-level incentives (at the discretion of state policy makers) or with the electricity production credit (45Y) which provides an incentive of up to USD 30/MWh for the electricity input. The Department of the Treasury published draft rules for eligibility in December 2023, held a public hearing in March 2024 and published the final rules in January 2025.

Hydrogen producers aiming to demonstrate electricity consumption from specific generators (e.g. solar, wind) must procure and retire matching Energy Attribute Certificates that meet requirements defined in the rules. Specifically:

- **Incrementality**. The electricity generation feeding into the hydrogen production facility should begin operating within 36 months of the facility start-up. There are two main exemptions to the condition. First, for nuclear plants that are at risk of retirement and co-dependent on the hydrogen investment for up to 200 MWh per reactor. Second, for electricity from states that have an electricity decarbonisation standard with a zero GHG emissions target by 2050 or earlier and a GHG cap programme that is legally binding, with a carbon price floor of at least USD 25/t CO_2-eq and a non-compliance penalty of at least USD 90/t CO_2-eq. Currently, California and Washington meet such conditions.
- **Time-matching**. Annual correlation between the electricity input and hydrogen production until the end of 2029 with hourly correlation starting afterwards for all the facilities (i.e. no grandfathering).
- **Deliverability**. The electricity generation and the hydrogen production facility should be in the same grid region as defined in the final rules (these regions are based on the National Transmission Needs Study).

For methane-based production, facilities must account for carbon capture rates based on annual averages. For upstream emissions, 45VH2-GREET has default values, but companies can also use their own values if they have been verified by the Environmental Protection Agency under the Subpart W rules within their Greenhouse Gas Reporting Program. The methodology to calculate lifecycle GHG emissions (including emissions in counterfactual scenarios) is defined for several gases including methane from wastewater, animal manure, landfills and coal mines. Blending of these alternative gases cannot be used to bring hydrogen with a high emissions intensity within the GHG limit to receive (or increase) incentives. The rules also specify a book-and-claim system for natural gas alternatives from 2027 and detail the information that those systems would need to provide.

Companies interested in pathways that are not in 45VH2-GREET may apply to DoE for an emissions value through their Emissions Value Request Process, once they have completed a Class 3 FEED study. Companies can then submit this emissions value to the Internal Revenue Service (i.e. "file a petition for a provisional emissions rate") when seeking a corresponding tax credit for hydrogen production.

Other policy instruments

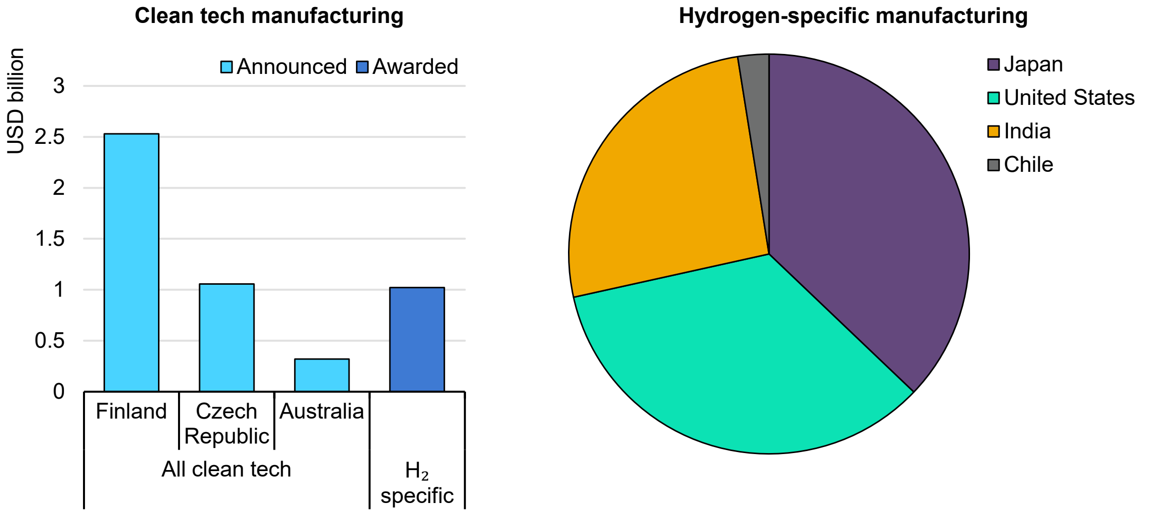
Industrial policies to support domestic manufacturing of hydrogen technologies

Since GHR-24, four different countries have awarded a total of USD 1 billion for electrolyser manufacturing (Figure 6.4). **Japan** awarded USD 379 million to four projects that could support 6 GW/yr of alkaline electrolyser manufacturing, the equivalent of 10 GW/yr of membranes for proton exchange membrane (PEM) electrolysers and 105 000 fuel cells for transport applications. The **United States** promotes manufacturing through the 48C tax credit from the Inflation Reduction Act (IRA). In 2024, it awarded USD 308 million to seven projects in the first round of approved projects, and USD 43 million to a further two projects in the second round in January 2025. **India** awarded INR 22 billion (USD 265 million) to 13 projects for a total electrolyser manufacturing capacity of 1.5 GW/yr, of which 0.4 GW/yr is expected to use a domestically produced electrolyser stack. 0.3 GW/yr were allocated to large-scale (up to 300 MW/yr) domestic manufacturing and 100 MW/yr were for small-scale (up to 30 MW/yr) manufacturing. Incentives are provided for 5 years, decreasing from USD 53/kW to USD 18/kW. **Chile** awarded USD 25.6 million to three projects (from ten applications) to manufacture alkaline electrolysers, potentially triggering a total investment of more than USD 50 million.

The update to **France**'s hydrogen strategy confirmed the allocation of more than EUR 3 billion of funding (across the past couple of years) for electrolyser manufacturing, including four electrolyser production plants across three technologies (alkaline, PEM, solid oxide), for fuel cells for transport applications, and for key components (e.g. membranes).

Hydrogen technologies were also included as part of broader packages targeting clean technology manufacturing. **Finland** announced a separate EUR 400 million programme for industrial decarbonisation that includes technology manufacturing. Grants are to be awarded in 2025, and projects should be completed within 36 months of receiving the grant. Elsewhere in Europe, the **Czech Republic** proposed a EUR 960 million package for manufacturing including electrolysers.

Figure 6.4. Public funding for electrolyser and clean technology manufacturing since the Global Hydrogen Review 2024



Notes: Public funding for "Clean tech manufacturing" includes broader funding packages that will, in part, be allocated to hydrogen technologies, although the exact share going to such technologies has not yet been determined. Funding for both electrolyser and fuel cell manufacturing is included.

Since GHR-24, four different countries have awarded a total of USD 1 billion for electrolyser manufacturing.

Not all the support provided for electrolyser manufacturing had an explicit budget allocated. In **India**, the state of Telangana announced a 25% CAPEX subsidy for electrolyser and fuel cell manufacturing, capped at a maximum of INR 300 million (USD 3.5 million) for plants of 0.5-3 GW/yr. This is part of the state's Green Energy Policy (see Strategies and targets above), which also includes incentives beyond manufacturing.

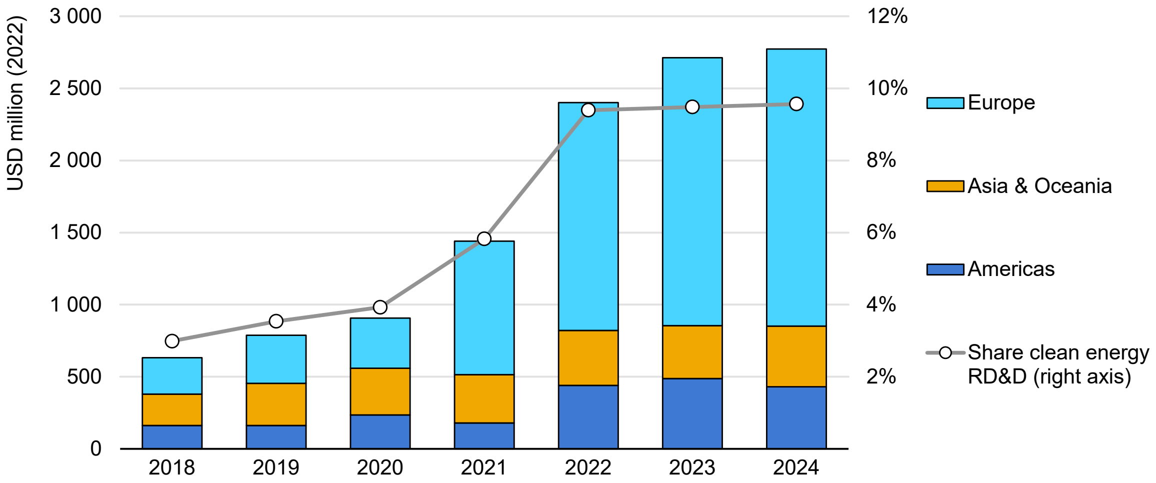
Promotion of RD&D, innovation and knowledge-sharing

Government investment in RD&D in hydrogen technologies remained robust in 2024, exceeding the historical record of 2023 by more than 2% (Figure 6.5).[94] In the past 5 years alone, RD&D spending on hydrogen technologies has nearly

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

quadrupled to reach almost USD 2.8 billion, representing a share of almost 10% of total clean energy RD&D spending. To put this growth into perspective, total clean energy R&D spending has grown at an annual pace of 5% since 2019.

Figure 6.5. Government RD&D spending on hydrogen technologies by selected regions, 2018-2024



Note: Data includes IEA Member countries.

Public budgets for RD&D on hydrogen technologies remained stable in 2024 at nearly 10% of the clean energy RD&D budget.

Within IEA member countries, two-thirds of RD&D funding is from Europe. At the EU level, the Clean Hydrogen Partnership is the main funding platform using grants, with a call of EUR 185 million opening in January 2025. The call covered 19 different topics including 2 related to hydrogen valleys (EUR 80 million) and seven to renewable hydrogen production (EUR 40 million). This level of annual funding should be maintained at least until 2027, as the partnership is part of the EU Multiannual Financial Framework that has been agreed for the 2021-2027 period. Funding from 2028 will be defined as part of the new financial cycle (2028-2034) which will start to be discussed in mid-2025.

In the **United States**, for FY2026, the latest budget proposal from July 2025 looks to entirely cut the hydrogen funding for the Office of Energy Efficiency and Renewable Energy (from USD 170 million in FY2024) and reduce the funding for the Office of Fossil Energy and Carbon Management. This is planned to be finalised before October 2025.

Elsewhere, **Australia** has established the Future Made in Australia Innovation Fund with AUD 1.5 billion (USD 1 billion) of funding. AUD 500 million was allocated to clean technology manufacturing (including electrolysers), AUD 750 million to low-emissions metals (including direct reduced iron from renewable hydrogen) and AUD 250 million to low-carbon liquid fuels. The **Netherlands** published the results of a public consultation on its EUR 380 million programme to demonstrate offshore hydrogen production. The first tender for 30-50 MW of electrolysis with a starting operating date of 2031 could be launched in 2025. **Luxembourg** also launched a tender with a budget of EUR 110 million for demonstration projects for 12 MW of electrolysis, providing CAPEX support of up to 45%, and OPEX support of up to EUR 10/kg.

China's National Energy Administration (NEA) published a plan for pilot initiatives across 11 areas of the hydrogen value chain targeting commercial deployment by June 2028. Each pilot should demonstrate technological progression, commercial potential, substantial carbon reduction benefits, and replicable frameworks. For hydrogen production, electrolysers should be of at least 100 MW, predominantly powered by paired renewable energy, with no more than 20% of renewable power from the grid. The minimum length for hydrogen pipelines is 100 km and the minimum size for storage projects is 20 000 Nm^3. The NEA focuses on uses for refining, coal-to-liquid replacement, power generation and long-duration energy storage with at least 1 000 tpa of hydrogen use.

International co-operation

Over the past year, multilateral co-operation on renewable hydrogen has continued to advance across key international fora.

At the 15th Clean Energy Ministerial (CEM) in October 2024, ministers launched the Action Plan to Accelerate Future Fuels, covering "clean" hydrogen[95] and its derivatives. The plan was endorsed by nine countries, is supported by the private sector and aims to accelerate the use and supply of future fuels by promoting demand as well as integrated supply chains and standards for lifecycle carbon accounting. The International Hydrogen Trade Forum (IHTF) (a high-level inter-governmental forum established in 2023 under the umbrella of the CEM Hydrogen Initiative) hosted two high-level dialogues focused on the development of emerging trade corridors. In May 2024, Ministerial officials discussed analysis carried out by IHTF and the Hydrogen Council, and in October 2024 debated the financing solutions, infrastructure developments and standardisation needs during a dedicated CEM/G20 IHTF side-event.

In November 2024, COP 29 featured several key developments on hydrogen:

- The Hydrogen Declaration was endorsed by 62 governments and 47 non-state actors. The declaration called on countries and stakeholders to scale up low-emissions hydrogen production, and to accelerate the decarbonisation of

[95] See Explanatory notes annex regarding the use of the term "clean" hydrogen in this report.

existing hydrogen from unabated fossil fuels, especially in hard-to-abate sectors. The areas of action include demand creation, global standards for certification schemes, and financial and technical assistance.

- The Hydrogen Industry Call to Action, endorsed by nearly 20 hydrogen associations and initiatives, urged a collective commitment to scaling demand for clean hydrogen and its derivatives by 2030, supported by offtake incentives, mandates, and integration into nationally determined contributions.
- The Call to Action for Maritime Sector Decarbonisation, endorsed by more than 50 stakeholders across the maritime value chain, including ship owners, operators, cargo owners, and renewable hydrogen producers, aims to incentivise the production and offtake of "green hydrogen"[96] and hydrogen derivatives. It underscores the need for co-ordinated supply and demand-side efforts and calls for the adoption of a mandatory package of measures by the International Maritime Organization in 2025, including a GHG intensity fuel standard and a GHG levy.

In addition, the 2024 Breakthrough Agenda Report outlined new Priority International Actions for 2025 under the Hydrogen Breakthrough, aiming to make renewable and low-carbon hydrogen[97] globally accessible and affordable by 2030. These actions prioritise enhanced international co-operation in strategic areas, with particular attention to supporting emerging markets and developing economies (EMDEs). As part of these efforts, a key financing milestone was reached with the joint commitment of 12 Development Finance Institutions to support the 10 GW Lighthouse Initiative, which aims to advance large-scale renewable hydrogen projects in EMDEs to reach FID by 2030.

Japan signed 70 memoranda of understanding (MoU) in August 2024 with partners at the Asia Zero Emission Community ministerial meeting in Jakarta to support sustainable fuel markets and hydrogen-related investments.

These agreements reflect growing momentum for international collaboration on low-emissions hydrogen, with a strong focus on infrastructure development, technology promotion, and the creation of markets for low-emissions energy sources.

[96] See Explanatory notes annex regarding the use of the term "green" hydrogen in this report.
[97] See Explanatory notes annex regarding the use of the term "low-carbon" hydrogen in this report.

Certification, standards and regulations

Standards, certification and regulation on the environmental attributes of hydrogen

Certification

Some countries and regions (Canada, European Union, India, United Kingdom, United States) now have a certification scheme in place with a defined methodology for GHG emissions quantification. In several others (Brazil and the rest of Latin America, Japan, Korea), a certification scheme and an emissions threshold have been announced, but the definition of the methodology and rules to measure GHG emissions are still pending. Others still (Australia and Switzerland) are working towards putting in place a guarantees of origin scheme to promote transparency.

Efforts are needed to advance the schemes that are still lacking detail on methodology, with the aim of standardisation as soon as possible using the International Organization for Standardization (ISO) guidelines that will become available in 2025/2026. Mutual recognition and interoperability of the schemes that already have rules in place is crucial; while certification schemes are typically based on the policy objectives, regulations and targets in each jurisdiction, use of a common methodology facilitates their comparability. A modular approach to quantify emissions from different parts of the value chain, and combination with a digital product passport, could further facilitate global trade.

ISO continues to make progress on the ISO-19870-x series of standards being developed under the ISO TC197 Subcommittee for the assessment of lifecycle GHG emissions associated with the hydrogen supply chain. Part 1, related to hydrogen production, progressed to the enquiry stage, during which ISO members had 12 weeks to provide comments. This means it could become a standard before the end of 2025. Parts 2 to 4, related to transport to the consumption gate using liquid hydrogen, ammonia and liquid organic hydrogen carriers, remain on track to become standards in 2026.

In **Australia**, a public consultation on legislation defining the methodology for GHG emissions quantification began in June 2025 for its "Product Guarantee of Origin" (PGO) scheme, with a view to begin using it by the second half of 2025. PGOs are not tradeable, but rather are designed to track information about a batch of hydrogen, such as on the electricity used for production. If production uses electricity generated from a renewable energy source, the certificate must state whether the electricity is from the grid which the facility is connected to. The period in which the electricity was produced and subsequently used can also be included.

The scheme will start with hydrogen and later expand to metals and low-carbon liquid fuels, and will be used to verify eligibility for funding programmes like Headstart and production tax incentives.

Canada published validation and verification guidance documents with specifications on estimating the carbon intensity of hydrogen production. The guidance is based on the Clean Fuel Regulations specifications to ensure consistency. Default carbon intensity factors for different production pathways are also provided.

Chile, the European Union and the Latin American Energy Association launched a project for capacity-building on meeting international standards for certification of hydrogen and derivatives intended for exports.

In **Korea**, the Korea Energy Economics Institute, which operates the national certification scheme, issued a public notice to support up to 15 projects in conducting a preliminary certification review based on design data and operation plans at the pre-operational stage. Certification is recommended for participation in the Clean Hydrogen Portfolio Standard.

India launched its Green Hydrogen Certification Scheme in April 2025 following a public consultation. The scheme defines a methodology for GHG emissions monitoring and measurement as an annual average, and covers only production (without hydrogen transport) from renewables and biomass. For other pathways, other Indian and ISO standards such as IS/ISO-14064 or ISO 19870 may be used. The Bureau of Energy Efficiency is due to define the institutions that can provide certification, monitoring and verification of the scheme. Certification and compliance with the 2 kg CO_2-eq/kg H_2 from the Green Hydrogen Standard are needed for projects to be able to receive incentives from the National Green Hydrogen Mission (which has a total funding equivalent to about USD 2.2 billion until 2030).

Poland proposed legislation to regulate the hydrogen sector which includes definitions (without GHG thresholds) for low-emissions hydrogen, renewable hydrogen and RFNBO.

In **Switzerland**, a guarantees of origin (GoOs) scheme has been in place since January 2025. This scheme is not a certification scheme and it is meant to contribute to transparency, avoidance of double counting and emissions reduction. The GoOs are standardised with those of the wider European Energy Community, which means the EU voluntary schemes can also be used as proof of compliance with the requirements. A minimum of 40% GHG reduction in comparison to hydrogen produced with fossil fuels is stipulated.

In the **European Union**, the European Commission accredited CertifHy, REDcert-EU and International Sustainability & Carbon Certification (ISCC EU) as voluntary schemes to demonstrate compliance with the RFNBO requirements of RED. ISCC EU has already been used to certify a synthetic methanol plant in Denmark, a 20-MW project in Germany and hydrogen from chlor-alkali in the Netherlands. CertifHy announced the recognition of Vinçotte, TÜV SÜD, TÜV Rheinland and SGS as certification bodies authorised to operate under its RFNBO scheme. TÜV SÜD issued the first RFNBO certificate to Tyczka, a German company involved in hydrogen production, transport and refuelling stations. CertifHy also issued RFNBO certificates to a 6.3 MW synthetic methane plant in Germany. The European Union also launched a public consultation on the "low-carbon" hydrogen[98] Delegated Act in September 2024, and published a methodology for GHG emissions savings in July 2025. This applies to non-renewable production pathways. Twelve EU member states have asked for a reassessment of the additionality rules in the methodology relating to renewable hydrogen and for a potential delay of the introduction of hourly correlation (currently scheduled to begin in 2030). The Parliament has also asked the European Commission to perform a study on the rules for RFNBO and propose changes to the Delegated Act if necessary.

Operational and safety standards

Since GHR-24, the ISO Technical Committee 197 published eleven new or updated international standards[99] related to hydrogen use in vehicles and fuel quality. 26 standards have been published so far, and 23 are under development, of which the majority relate to fuelling stations, fuelling protocols and vehicle fuelling system components. The International Electrochemical Commission (IEC)[100] published six standards on railway applications and fuel cell systems for small-scale power generation, with a total of 38 hydrogen-related standards now published in these areas.

China published four new standards: two for PEM electrolysers (GB/T 45539-2025, GB/T 45541-2025), approved in March 2025, and two for valves and containers of liquid hydrogen (GB/T 45027-2024, GB/T 45161-2024), approved in January 2025.

Canada published a roadmap for hydrogen codes and standards in April 2025. This identifies any gaps in standards for hydrogen technologies and processes across production, delivery, storage and end use. The gaps were assessed based on their potential implications, looking at urgency, criticality and activity within the

[98] See Explanatory notes annex regarding the use of the term "low-carbon" hydrogen in this report.
[99] ISO 19887-1:2024, ISO 14687:2025, ISO 19880-2:2025, ISO 19880-5:2025, ISO-19880-7:2025, ISO 19880-8:2024, ISO 19881:2025, ISO 19882:2025, ISO 24078:2025, ISO 22734-1:2025, ISO 17268-1:2025.
[100] The IEC covers standards for all electrical and electronic equipment from generation to end use.

sector, among other factors. The top priorities identified for the coming 18-36 months included standards for water electrolysis, carbon intensity, ammonia for hydrogen delivery and storage, and hydrogen use in steel production and heavy-duty vehicles. The roadmap also identifies 19 actions to support codes and standards developments.

In the **United Kingdom**, the British Standards Institution published a Publicly Available Specification (PAS 4445:2025) that provides recommendations on the design, construction and performance of large equipment that is either built to use hydrogen or designed to be converted to hydrogen for industrial and commercial applications.

The **United States** published the final rule on performance requirements for all motor vehicles using hydrogen as a fuel source. This includes requirements for the integrity of the fuel system and compressed hydrogen onboard storage. Separately, the Federal Aviation Administration published a safety and certification roadmap for hydrogen-fuelled aircraft which maps existing standards and certification readiness and identifies research needs and actions until 2032.

Regulations on infrastructure, permitting and other areas

Germany approved the hydrogen core network in October 2024 with a length of 9 040 km, down from 9 721 km in the draft application from July 2024. The network is expected to use 44% new pipelines and have a capital cost of EUR 18.9 billion. The network operators plan to complete 525 km in 2025, with the network completed by 2032. The plan will be revised every 2 years. Approval has not affected plans for financing of the network (which were described in GHR-24) including a cap on fees that can be charged to users, a regulated return on equity of 6.69% and an amortisation account that will be used to cover payments during the initial period of low utilisation. This account will be financed by a EUR 24 billion credit line from the German development bank KfW, which signed the loan agreement in November 2024. KfW made the first annual payment to the amortisation account for EUR 172 million in March 2025, which was then forwarded to the 18 network operators. In March 2025, the Federal Network Agency, which manages the regulation of networks, published its proposed tariff scheme for public consultation. The tariff proposed was EUR 25/kW per year based on two conditions: the tariff must fully offset the costs incurred during the ramp-up phase by 2055 and be in line with market conditions. The tariff will be applied at all entry and exit points of the hydrogen core network until 2055.

In **Spain**, the full amount of funding requested by Enagás (EUR 75.8 million) under the Connecting Europe Facility Energy (CEF-E) for feasibility and engineering studies was approved by the European Commission in January 2025. This relates to Projects of Common Interest (PCIs) within the H2Med corridor and the initial sections of the Spanish hydrogen backbone. Spain is progressing according to the planned timeline for both projects. In April 2025, Enagás launched the Conceptual Public Participation Plan, an 18-month stakeholder engagement initiative involving autonomous communities, local administrations, institutions and citizens in the early planning stages to ensure transparency and promote social and environmental integration. The Spanish hydrogen backbone, 2 600 km of pipeline structured into 15 segments, has been designed based on demand identified through the Call for Interest conducted in 2023. In parallel, four additional segments representing 1 480 km were submitted in December 2024 to the second PCI selection round, with a final decision expected by the end of 2025. An FID for the Spanish hydrogen backbone is expected by 2027, with construction scheduled to begin in 2028 and commissioning targeted by 2030. The total planned investment amounts to EUR 2.645 billion.

In the **Netherlands**, the Dutch energy regulator, ACM, published a market report in May 2025 with an assessment of the hydrogen transmission tariffs. From 2033, at the latest, ACM will set tariffs based on actual incurred costs. Before then, some of the options proposed to deal with the low utilisation during the early stages are to use intertemporal cost allocation (i.e. spreading the cost recovery for the network over time), direct government subsidies to the network operators, and indirect government support, for example through loan guarantees. In 2022, the government reserved up to EUR 750 million until 2031 to cover the mismatch between hydrogen demand and the network capacity. This was enough to cover 50% of the network costs, with the estimate increasing to EUR 3.8 billion since then, and the government reserving EUR 2.5 billion in its budget proposal in 2025. In November 2024, ACM published new rules for third-party access (TPA) to hydrogen terminals. The Netherlands will use negotiated TPA, which means the terminal operator and potential user will agree the conditions and rates for terminal use. The rules entered into force in February 2025.

In March 2025, **Denmark** launched a public consultation on the method for allocating the capacity of the hydrogen network. The guidelines propose that market participants are allocated the amount of capacity they bid for on first-come-first-served basis. In the case that demand accounts for more than 80% of the network capacity, at a given year and point of the network, an auction will be used to allocate the capacity. The network capacity for transmission to Germany must be offered as bundled capacity (i.e. together with the injection capacity to the German transmission network). To address low utilisation during the early phase, Denmark is opting for combination of a revenue cap[101] for a period of 4 years and an intertemporal cost allocation that should be in place by 2027. The Transmission

[101] The utility regulator sets an upper limit annually for how much the infrastructure companies may charge system users. This is based on the average of costs in previous regulatory periods and operators can keep the profits if costs are lower.

System Operator, Energinet, is expected to draft the tariff methodologies, which will then need to be approved by the utility regulator.

The **United Kingdom** opened a public consultation to allow 2% blending in the national gas transmission network. The proposal would allow producers to inject hydrogen in the grid if other users are unable to take supply. This measure is meant to improve conditions for supply projects by guaranteeing offtake, and the 2% level is based on an assessment of changes needed for the downstream users, and safety. The consultation is separate from the blending level for the distribution network.

At the **European Union** level, the EU Agency for Cooperation of Energy Regulators (ACER) launched a public consultation in March 2025 on intertemporal cost allocation mechanisms for financing hydrogen infrastructure. The methodology selected would need to be adopted by national regulatory authorities. As per the Hydrogen and Decarbonised Gas Market Regulation, ACER is required to issue a recommendation on intertemporal cost allocation by August 2025. The European Union also granted over EUR 250 million to 21 development studies for hydrogen infrastructure in January 2025.

In emerging markets, **Oman** launched a single permit system intended to simplify the permitting approval process and accelerate access to land as part of its third hydrogen auction round. **China** included hydrogen as an energy carrier in its Energy Law. This means it is no longer classified as a hazardous substance, which should ease the regulatory burden for hydrogen production once specific legislation is put in place. The legislation also covers the promotion of the hydrogen industry.

Chapter 7. Southeast Asia in focus

Highlights

- Hydrogen demand in Southeast Asia reached 4 Mt in 2024, almost 4% of the global total. Hydrogen production accounted for about 8% of the regional gas supply and 1% of regional CO_2 emissions. Indonesia represents over a third of regional demand, followed by Malaysia (22%), Viet Nam (15%) and Singapore (12%). Nearly half of all demand is for ammonia, of which two-thirds comes from Indonesia alone. Refining accounts for a third of demand, with 40% located in Singapore; methanol represents the remaining 20%, with 69% in Malaysia. The region currently exports ammonia (15% of production) and imports methanol.
- Indonesia, Lao PDR, Malaysia, Singapore and Viet Nam all have hydrogen strategies in place, and there is an opportunity to implement policies encouraging fuel shifting in existing applications, as well as on certification.
- Projects in the pipeline for low-emissions hydrogen production to 2030 add up to almost 480 ktpa. More than 90% of this in Indonesia and Malaysia; two projects alone represent nearly half of this capacity. To date, 6% of the capacity in the pipeline has reached final investment decision (FID).
- Indonesia, Malaysia and Viet Nam have sufficient existing ammonia demand to enable economies of scale in low-emissions ammonia production. Indonesia and Malaysia also have this potential for methanol production. State-owned enterprises provide an opportunity to decarbonise current hydrogen uses.
- Use of hydrogen for steel production could create an opportunity for Indonesia and Viet Nam, which are home to most of the region's steel production and iron ore reserves, and for the Philippines and Thailand, which rely heavily on steel imports to meet demand. Hydrogen-based steel could contribute to satisfying the expected regional steel demand growth, but faces competition from China.
- In the maritime sector, more than 85% of total energy demand is from international shipping in Singapore, which is pursuing a multi-fuel strategy, performing trials and defining technical standards for ammonia and methanol bunkering. In aviation, demand is concentrated in a few airports, so supplying these with synthetic fuel could make large strides towards decarbonisation.
- Near-term actions include prioritising renewables deployment, which could have positive consequences for the hydrogen sector, such as a lower cost of capital, industry experience and standardised processes. Pilot projects that enable gradual learning for large projects can be useful, as can leveraging existing hydrogen applications to create economies of scale and anchor demand.

Overview of the regional energy system

Energy demand growth in Southeast Asia is expected to accelerate in the near term, increasing CO_2 emissions

The economy of Southeast Asia is growing fast, and so is its energy demand. In 2024, the ten countries of the Association of Southeast Asian Nations (ASEAN) represented 6% of global GDP, 9% of the world's population, 5% of energy demand, 5% of energy-related CO_2 emissions, and 2% of clean energy spending. Since 2000, population has grown by more than 30% and energy demand has more than doubled, although there are large variations among countries. In 2024, of the nearly 700 million people living in the region, almost 3% still lacked access to electricity and 18% to clean cooking. Since 2010, the region has accounted for 11% of global energy demand growth, and energy demand is expected to grow further in the future. Fossil fuels met nearly 80% of demand growth over this period. In 2024, Southeast Asia imported more than 50% of the 5 mbpd of oil demand, resulting in a net oil import bill of nearly USD 135 billion – equivalent to close to 4% of regional GDP. More than half of these imports were from the Middle East.

Energy-related CO_2 emissions in Southeast Asia reached nearly 2 Gt CO_2 in 2024, doubling from 2006 (Figure 7.1). 85% of these emissions were concentrated in Indonesia, Malaysia, Viet Nam and Thailand. Looking forward, six ASEAN countries have set targets for net zero emissions by 2050, Indonesia by 2060, and Thailand by 2065. Myanmar[102] and the Philippines do not have net zero targets. Based on existing policy settings, Energy-related CO_2 emissions from the region are expected to increase by more than 20% by 2035 (compared to a 2024 baseline).

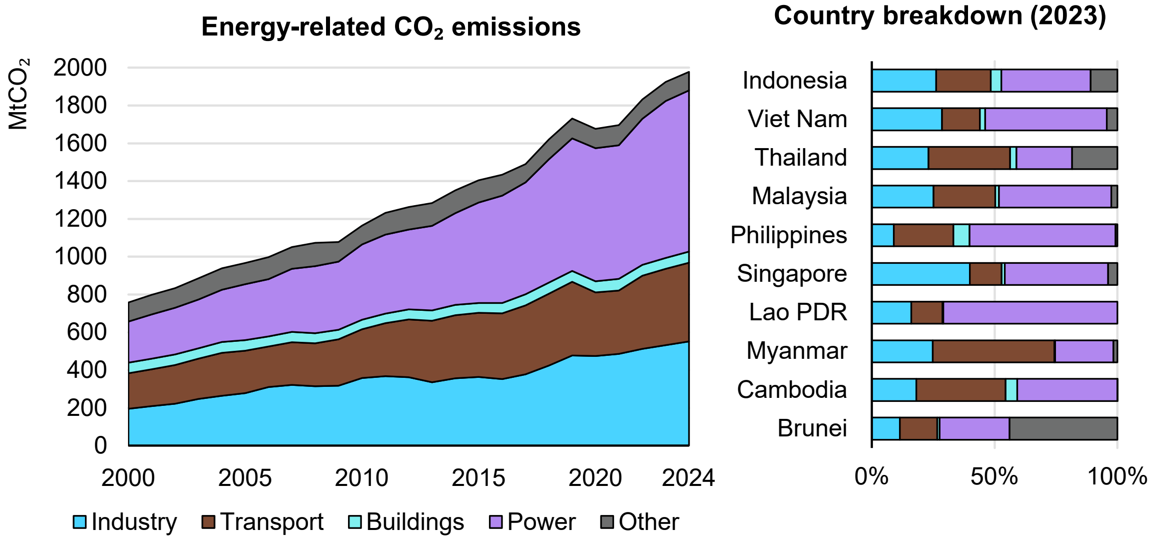
Regional co-ordination on energy policy is, in part, carried out through the ASEAN Plan of Action for Energy Cooperation. For the 2021-2025 period, some of the targets relevant for hydrogen include an aspirational target of a 23% renewable share in the primary energy supply and 35% renewable share in installed power capacity by 2025. The next phase (2026-2030) is still under preparation, and hydrogen is mentioned as one of the areas to explore.

Carbon pricing, which could be used to close the cost gap for hydrogen use, is not currently widespread in the region, although more countries are considering introducing measures.[103] Singapore increased its carbon tax to USD 19/t CO_2 in

[102] Myanmar has a net zero target for the land use, land use change and forestry (LULUCF) sector (i.e. a subset of the entire economy) by 2040, which is explicitly conditional on international finance and technical support.
[103] An Emissions Trading System (ETS) was proposed in Malaysia in 2021, in Thailand in 2016, in Viet Nam in 2017; as-yet undefined schemes have been proposed in Brunei (2021) and the Philippines (2024). There are no announcements for Cambodia, Myanmar and Lao PDR. Malaysia is planning to introduce a carbon tax in 2026.

2024 (from USD 4/t CO_2), covering 71% of national emissions. Indonesia has an Emissions Trading System (ETS) covering 24% of national emissions with a price level of less than USD 1/t CO_2 and has been considering the introduction of a carbon tax since 2021.

Figure 7.1 Historical energy-related CO_2 emissions from Southeast Asian countries, 2000-2024



IEA. CC BY 4.0.

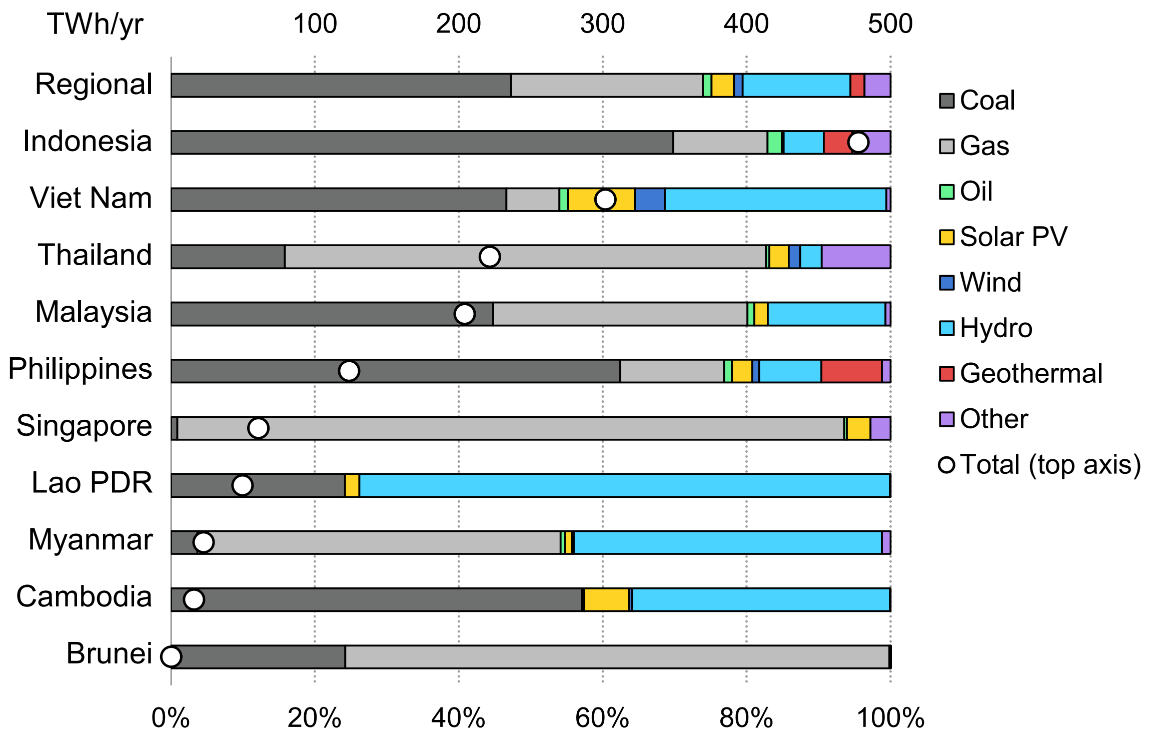
Southeast Asia had almost 2 Gt of energy-related CO_2 emissions in 2024 – twice the amount in 2006.

The power sector is growing strongly, but uptake of low-emissions generation technologies remains low

In 2024, 36% of the energy-related CO_2 emissions in Southeast Asia came from the power sector. Total electricity generation was 1 480 TWh, of which 47% came from coal, 27% from gas and 15% from hydropower. About 4% came from solar and wind (Figure 7.2). Electricity generation has nearly quadrupled since 2000, when it was 370 TWh, and more than 70% of the growth has been covered by fossil fuels. Looking ahead, generation is expected to increase by almost 60% by 2035 in the Stated Policies Scenario (STEPS), with more than half of the growth met with renewables.

In 2024, Southeast Asia had a total generation capacity of 380 GW, of which more than two-thirds were from fossil fuels, split nearly equally between coal and gas, 60 GW was hydropower, 36 GW was solar PV, 8 GW was onshore wind, and 1.5 GW was offshore wind. Viet Nam alone had 19 GW of solar PV capacity, although this represented just 9% of the total generation mix. Feed-in tariffs in Viet Nam expired in 2021 and were introduced again for solar in April 2025. Solar faces grid integration challenges, which might slow down deployment in the short term. Indonesia, which has the largest electricity demand in the region, had less than 0.2% of generation from solar PV. Viet Nam also leads in wind, with 5 GW of onshore wind and all of the region's offshore capacity. Indonesia and the Philippines combined have 4.6 GW of geothermal.

Figure 7.2 Electricity generation mix and total generation by Southeast Asian country, 2024



Power generation is currently dominated by fossil fuels in most Southeast Asian countries and hydropower has the largest role among renewable technologies.

In terms of policies for the power sector, several countries have ambitious plans to scale up renewables. Brunei has a capacity target of 30% renewables by 2035, Indonesia targets doubling renewable energy in the generation mix to 30% by 2035, the Philippines has a target of 35% renewable generation by 2030, and Malaysia has a roadmap with a 57 GW target for solar PV by 2050. Based on announced 2030 targets, Indonesia is expecting the fastest growth in the region, aiming to more than triple renewable capacity to 44 GW (from 14 GW in 2024). Similarly, the Philippines aims to increase renewable capacity to nearly 30 GW (from 10 GW), and Viet Nam targets the largest absolute growth, aiming to add more than 35 GW by 2030. Achieving these targets would require significant acceleration of recent renewables deployment trends, especially for Indonesia and the Philippines. To date, the most common policy instruments used in the region are auctions and feed-in tariffs, and some of the policies used for renewables could be used as a starting point for hydrogen. For example, Indonesia has ease of access to low interest loans, tax allowances and accelerated regulatory processes for renewables. In the Philippines, the Renewable Energy Act introduces fiscal incentives which also cover renewable hydrogen production, and production from nuclear falls under the Energy Efficiency and Conservation Act, which offers different incentives.

In terms of generation cost, the levelised cost of electricity (LCOE) for solar PV in Viet Nam was USD 85/MWh in 2023, while the LCOE for onshore wind was USD 80/MWh. This is comparable to power generation from unabated fossil fuels. An LCOE of USD 50/MWh used for electrolysis would be equivalent to about USD 2.5/kg H_2.[104] Data from past auctions provides an indication of the LCOE across countries: Cambodia has achieved the lowest costs in the region for solar PV (USD 26/MWh in 2021), while costs in the Philippines and Thailand remained high (USD 76/MWh and USD 69/MWh, respectively) in 2023. Costs for onshore wind auctions are even higher, with USD 100/MWh in the Philippines and USD 91/MWh in Thailand, which would make renewable hydrogen too expensive. In addition, renewable hydrogen assets are capital intensive, which makes a low cost of capital essential to achieve low costs. However, the cost of capital in Southeast Asia is currently at least twice that of advanced economies or China for renewable assets.

Hydrogen status today

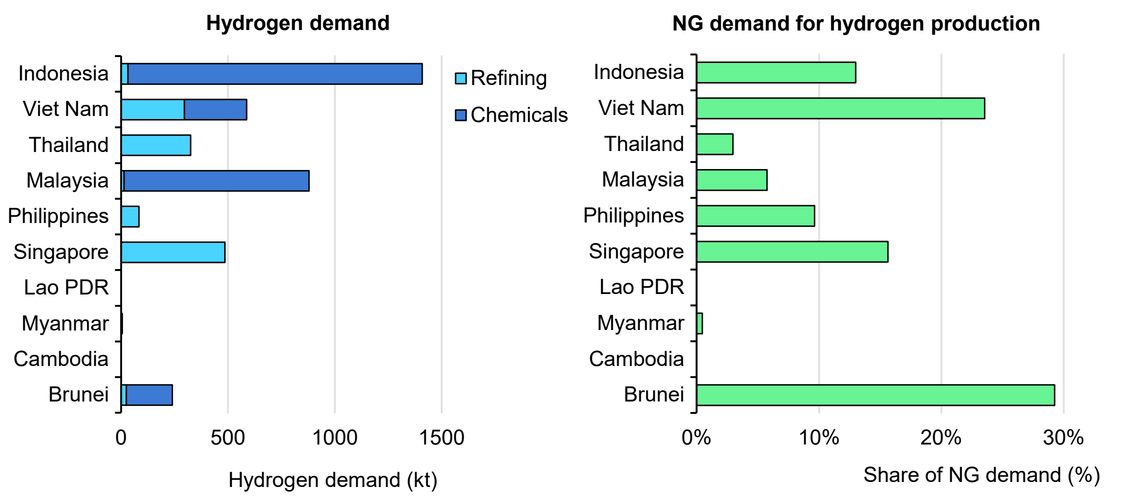
Hydrogen demand in Southeast Asia reached 4 Mt in 2024, up from 3 Mt in 2012. The majority of demand is concentrated in four countries: Indonesia represents over a third of regional demand, followed by Malaysia (22%), Viet Nam (15%), and Singapore (12%). In terms of sectors, ammonia represents nearly half of the hydrogen demand, with nearly two-thirds of this coming from Indonesia. Demand for refining is driven by Singapore, with its three refineries with a total processing capacity of 1.4 mbpd (nearly six times its domestic oil demand). Methanol is only produced in three countries, with the largest production in Malaysia (Figure 7.3). Refining and ammonia demand have grown 25-45% in the past 10 years. There are three large plants for methanol, and there has been a step change in production since they entered operation in 2009. Infrastructure currently remains limited in Southeast Asia, other than 13 ammonia terminals.

Nearly 80% of the demand was satisfied with hydrogen produced from natural gas and the rest was from industrial by-product. There is no production from coal in the region. The natural gas used for hydrogen production can represent a

[104] With an efficiency of 67% on a lower heating value basis.

significant share of domestic gas demand. In Brunei, for example, this share is almost 30%, while in Viet Nam it is nearly 25%. These shares are smaller when expressed in terms of natural gas production for Brunei, Indonesia, Malaysia and Myanmar, since these countries export 25-75% of their gas production. At a regional level, hydrogen production represented about 8% of the gas supply in 2024 and more than 1% of regional energy-related CO_2 emissions[105]. As in the rest of the world, there is currently no hydrogen trade, but there is trade of hydrogen derivatives (see following sections on ammonia and methanol).

Figure 7.3 Hydrogen demand by sector and country and natural gas demand for hydrogen production in Southeast Asia, 2024



Notes: NG = natural gas. Chemicals include hydrogen demand for ammonia and methanol. Natural gas demand is based on 2022 numbers (last data point available from national statistics). There is lack of country-level data for the split of hydrogen production and industrial by-product, so the figure assumes all countries have the same split as the regional average (about 80% from natural gas reforming).

Hydrogen demand in Southeast Asia was 4 Mt in 2024, of which 85% came from Indonesia, Malaysia, Viet Nam and Singapore.

Hydrogen policy landscape

Hydrogen strategies are in place, but concrete actions are needed as a follow-up

Five Southeast Asian countries have now published a hydrogen strategy: Singapore (2022), Indonesia (2023), Malaysia (2023), Viet Nam (2024) and Lao PDR (2025). To date, none of the countries has a certification scheme in place or related GHG emissions thresholds and methodologies, but work towards this aim

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

is underway in Indonesia, the Philippines and Thailand. Of the hydrogen-related COP initiatives, 5 countries (Brunei, Malaysia, the Philippines, Singapore and Thailand), representing 30% of the current regional renewable capacity, endorsed the target of tripling renewables by 2030. Three countries (Brunei, Malaysia and Singapore), accounting for 40% of the current regional hydrogen demand, signed the Declaration of Intent from COP 28 for mutual recognition of hydrogen certification schemes. Three countries (Indonesia, Malaysia and Singapore), accounting for 70% of the current regional hydrogen demand, signed the Hydrogen Declaration from COP 29.

Singapore's strategy covers imported hydrogen as a fuel for road transport, shipping, aviation and power generation. The strategy considers hydrogen as an alternative for decarbonising the power sector, which contributes to 40% of national emissions, and a solution to deal with the lack of domestic resources and land availability. The government estimates that hydrogen could meet up to 50% of electricity demand by 2050. In 2022, Singapore launched a request for proposals (RfP) for using ammonia in gas turbines of 55-65 MW, and for 0.1 Mtpa of ammonia bunkering. Two consortia were selected in 2024 and the lead developer is expected to be announced in 2025. In 2023, emission standards were introduced for new and repowered gas turbines, including readiness to use at least 30% hydrogen (or alternative fuels) and the ability to be retrofitted to 100% hydrogen in the future. Since 2023, Singapore has launched two RfPs for three 600-MW gas turbines starting operations between 2027 and 2030.[106] Power generation from hydrogen is also included in the national finance taxonomy, where a threshold of 100 g CO_2-equivalent/kWh is set for activities to be classified as contributing substantially to climate change mitigation. As implementation of the hydrogen strategy progresses and the strategy evolves, there is potential to include measures towards decarbonising the use of hydrogen as feedstock for refining, which is not currently addressed by the strategy, but is responsible for all existing use of hydrogen. Further updates to the strategy would also provide an opportunity to include specific indicators, targets, scenarios or preferred production routes, and the associated timeline.

Indonesia's strategy is based on three key pillars – decarbonisation, energy security and exports – with nine action areas including hubs, hydrogen use in mini-grids and power generation, a carbon pricing scheme, and definition of a hydrogen certification scheme. The strategy estimates that domestic hydrogen demand could reach nearly 5 Mtpa by 2060 in a net zero emissions scenario, nearly equally distributed between transport and industry. Renewable electricity (including

[106] For reference, Singapore's total installed capacity was in the order of 13 GW in 2023.

geothermal), bioenergy, nuclear and fossil fuels with carbon capture, utilisation and storage (CCUS) are considered as potential energy sources for hydrogen production.

Indonesia also published a hydrogen and ammonia roadmap in April 2025 as a follow-up to the strategy. The roadmap includes targets and action plans for hydrogen development across three stages, guided by the aims of the strategy. The specific targets are more ambitious than in the 2023 strategy but also reflect the uncertainty in hydrogen use. By 2060, demand (including for ammonia production) could reach 3.4-11.8 Mtpa, with the main uncertainty coming from the power and industry sectors. For the upper bound, demand in the power sector would represent 4 Mtpa, chemicals 2.6 Mtpa, light industry 1.9 Mtpa, steel 1.8 Mtpa and fuel cell electric vehicles and ships 1 Mtpa. Hydrogen supply could reach 6.4-17.5 Mtpa by 2060, implying a potential export of 35-45% of production. Up to 15.5 Mtpa of that supply would come from electrolytic hydrogen, including 5.1 Mtpa produced from hydropower, 1.85 Mtpa from biogas reforming with the rest produced from fossil fuels with CCUS. For ammonia, about 40% of the demand in 2060 would come from co-firing. As part of the roadmap, more than 200 short-term actions were identified to support the development of the hydrogen sector in the initiation phase. These include studies to be carried out in 2025 and 2026 that will inform policies to be adopted in the coming years. Work to develop a national certification scheme compatible with international standards is underway.

Malaysia's hydrogen roadmap includes two scenarios where hydrogen production reaches 7-15 Mtpa by 2050, driven by use as feedstock (2.3-5.6 Mtpa), for exports (3.2 Mtpa) and for industrial heat (0.5-1.3 Mtpa). Export opportunities are prioritised over the domestic market. Nearly half of the hydrogen is renewable hydrogen in 2050 in both scenarios, but prior to 2050 there is a greater reliance on hydrogen from fossil fuels with CCUS. The roadmap defines 79 targets across 3 time horizons and 5 strategic areas, including a review of incentives for hydrogen technologies by 2026, development of low-emissions industrial clusters by 2027 and the development of a certification scheme by 2035, as well as commissioning of an industrial-scale project by 2035.

Viet Nam's strategy includes a 0.1-0.5 Mtpa production target by 2030, from both renewable and fossil fuels with CCUS (in comparison to a current demand of 0.6 Mtpa), with a vision of 10-20 Mtpa to 2050. Exports are foreseen as early as 2030. The strategy defines seven broad action areas and actions for Ministries but does not specify indicators to track progress or timelines.

Lao PDR defines four phases of hydrogen development in its roadmap: a pilot and research phase, followed by implementation, commercialisation and exporting phases. Targets for the commercialisation phase include USD 250 million in investment, 100% import replacement of urea, 15% co-firing in cement and 100 MW of electrolyser capacity. The final phase includes targets of 8-9 GW of electrolysis across 9 hubs and 8 Mtpa of ammonia production. As a point of reference, Lao PDR had nearly 10 GW of renewables in 2023, with almost 99% of that capacity from hydropower. The roadmap defines 44 actions across 9 areas to achieve these targets, including tax incentives, credit guarantee schemes, public procurement, certification and knowledge exchange.

Among other countries that do not currently have a hydrogen strategy, in November 2023, **the Philippines** published draft hydrogen guidelines for public consultation. The guidelines define several tax incentives[107] being considered for renewable hydrogen, propose the establishment of a government committee that would develop a roadmap and oversee the implementation of the guidelines, and require companies to notify the government before engaging in any hydrogen activity. There is already a dedicated committee evaluating the possible policies that could be used for hydrogen deployment. Furthermore, the 2023-2050 Energy Plan delineated four areas of action in a strategic roadmap for hydrogen and its derivatives. This included the development of a hydrogen masterplan and a supporting national policy, legal and regulatory framework during 2023-2024. The roadmap and guidelines are still under development. In 2024, the Philippines also offered two areas to the north of Manila for exploration of natural hydrogen, where foreign entities can own 100% of the operations. There were five bidders in each area and contracts have been awarded. The contracts are expected to be awarded in 2025. The application process for two other areas is ongoing.

Thailand has also undertaken some preparatory work for a hydrogen strategy; hydrogen is considered as an alternative technology that can contribute to the target of carbon neutrality by 2050, used for power generation and industrial heat. This could be achieved through blending in the natural gas network, which could begin in 2030 with a 5% blend. Thailand has defined four action areas: developing a robust market and incentives for early adopters, promoting domestic research capabilities, and developing infrastructure including pipelines and storage as well as a supportive regulatory framework and standards. In 2023, the Hydrogen Policy Working Group of Thailand was established in the Energy Policy and Planning Office, with the aim of defining a 2025-2050 plan for hydrogen development. The plan is expected to be approved in 2025, followed by specific policies and incentives.

Some regional co-operation is being led by the ASEAN Centre for Energy, which is working on an ASEAN Low-Carbon Energy Technology Roadmap for hydrogen and ammonia. Hydrogen was also mentioned an area for enhanced collaboration

[107] Relating to income tax, corporate tax, value added tax and exemption from duties. There is no consideration of production tax credits.

in the last meeting of ASEAN Ministers of Energy (in September 2024). A key opportunity for future collaboration is in the next phase (2026-2030) of the ASEAN Action Plan for Energy Cooperation, which is under preparation and which could include specific targets and actions for hydrogen. Co-operation also takes place through the Asia Zero Emission Community (AZEC), an initiative started by Japan in 2023 to work together with Asian countries to promote decarbonisation. The areas for collaboration include development, demonstration and deployment of clean technologies including hydrogen, ammonia and CCUS. This initiative supported a Master Plan for Hydrogen and Ammonia in the Asian region and has led to the exploration of several hydrogen-related projects.

State-owned enterprises

State-owned enterprises provide an avenue to decarbonise current uses and spur growth of low-emissions hydrogen

In **Malaysia**, the national oil and gas company, PETRONAS, owns most of the existing hydrogen production capacity and has launched a separate entity (Gentari) to pursue integration of sustainable energy solutions including hydrogen. Its strategy targets production from fossil fuels with CCUS in 2024-2025, and renewable hydrogen in 2025-2027, aiming to produce 1.2 Mtpa by 2030. PETRONAS has a proprietary PEM electrolyser and is pursuing hydrogen exports to Japan using liquid organic hydrogen carriers, as well as aiming to develop an ammonia plant from fossil fuels with CCUS in Sarawak. The company is also exploring exports by pipeline to Singapore and floating platforms for producing low-emissions ammonia. In addition, PETRONAS is involved in projects outside Malaysia, with the largest being a 5 Mtpa ammonia plant in India through a joint venture with AM Green. The national utility company, Tenaga Nasional Berhad, is developing a renewable hydrogen, methanol and ammonia hub in Terengganu, based on hydropower and floating solar PV.

State-owned companies also play a role at the sub-national level in Malaysia. Sarawak Economic Development Corporation (SEDC) is a government-owned entity in charge of promoting emerging clean energy technologies. SEDC is one of the partners of the H2biscus project, which targets 850 ktpa of renewable ammonia production by 2028, and the H2ornbill project, which aims to export 88 ktpa of renewable hydrogen to Japan from 2030. In 2024, SEDC also partnered with Gentari to launch a hydrogen hub in Sarawak, which aims to standardise projects and use a modular approach.

In **Indonesia**, Pertamina has committed to a net zero emissions goal by 2060, aligned with the national goal. In 2021, it created a separate entity (Pertamina New and Renewable Energy [PNRE]), which includes hydrogen activities. It aims to produce 1 Mtpa of low-emissions hydrogen by 2030, 2 Mtpa by 2040 and 3 Mtpa by 2060, requiring a cumulative investment of USD 45-50 billion. The company already has 17 projects under development with a total capacity of 1.8 Mtpa by 2040, and targets exports starting in 2027. Several Pertamina subsidiaries are working together to produce hydrogen from geothermal energy, targeting 300 t/d of production at several sites. PNRE also established a collaboration with Genvia (a French company developing a solid oxide electrolyser) and is exploring natural hydrogen. In addition, Pertamina has partnerships with downstream users like Toyota, Hyundai and Tokyo Electric Power Company (which aims to import from Indonesia).

The state-owned electricity utility in Indonesia, PT PLN, is also involved in several hydrogen initiatives. In October 2023, PT PLN inaugurated a renewable hydrogen pilot plant (51 tpa) in Indonesia. In February 2024, it opened Indonesia's first hydrogen refuelling station in Jakarta. In May 2024, PT PLN and Singapore's Sembcorp Utilities signed a joint development study agreement to explore a green hydrogen and ammonia project in Indonesia. In September 2024, PLN adapted an existing geothermal power plant to produce hydrogen. In April 2025, PT PLN signed a joint study agreement with the Ministry of Transportation, PT HDF Energy Indonesia and PT ASDP Indonesia Ferry to conduct a study on the use of green hydrogen for the decarbonisation of the maritime transportation sector. PT PLN is also collaborating with ACWA Power to develop a 150 ktpa renewable ammonia plant, with FID expected by the end of 2025.

In **Thailand**, PTT Public Company Limited, the state-owned oil and gas company, has set targets to achieve net zero emissions by 2050. Its strategy focuses on integrating renewable energy across its operations and deploying emission reduction technologies. Hydrogen plays a central role in this approach, with plans to blend hydrogen with natural gas at a 5% ratio in the power sector by 2030. In 2024, PTT and the Hydrogen Thailand Association submitted nine hydrogen pilot projects to the government, which have been integrated into the national energy action plans. PTT has announced plans to develop a 1.2 Mtpa ammonia plant (see Low-emissions ammonia).

In **Brunei and Viet Nam**, the national oil companies BSP and PetroVietnam have committed to achieving net zero emissions by 2050, aligned with their respective national climate goals. PetroVietnam has also begun piloting projects in renewable hydrogen, renewable ammonia and CCUS as part of its broader transition strategy.

Opportunities in hydrogen production

Pipeline of low-emissions hydrogen projects

Pipeline is highly concentrated in Indonesia and Malaysia and needs to mature

There are 25 projects under development in Southeast Asia, adding up to almost 480 ktpa of hydrogen production by 2030 (Figure 7.4). Almost half of these projects involve a state-owned enterprise and 40% of the projects target exports. More than 90% of the capacity in the pipeline is in Indonesia and Malaysia. Just two projects account for nearly half[108] of this production: a nuclear plant with 1 GW of electricity output in Indonesia producing ammonia from 180 ktpa of hydrogen, targeting commercial operation by 2028[109] and a 150 ktpa plant using hydropower to produce ammonia in Malaysia and starting operations of the first phase in 2028. All the low-emissions hydrogen production to 2030 is expected to come from electrolytic hydrogen. The pipeline to 2030 does not have projects larger than 1 GW of electrolysis, and nearly 40% of the projects have an electrolyser smaller than 300 MW. Of all the capacity in the pipeline, 6% (27 ktpa) has reached FID, with 24 ktpa coming from a single project, the Tra Vinh project in Viet Nam, which uses 500 MW of wind and 100 MW of solar PV to feed a 240 MW electrolyser to produce 182.5 ktpa of ammonia. The project started construction in 2023 and is expected to start operations in 2027. The 6% of capacity to have reached FID is lower than the global average, but higher than in other developing regions such as Latin America and Africa, although the pipeline for those regions is much larger.

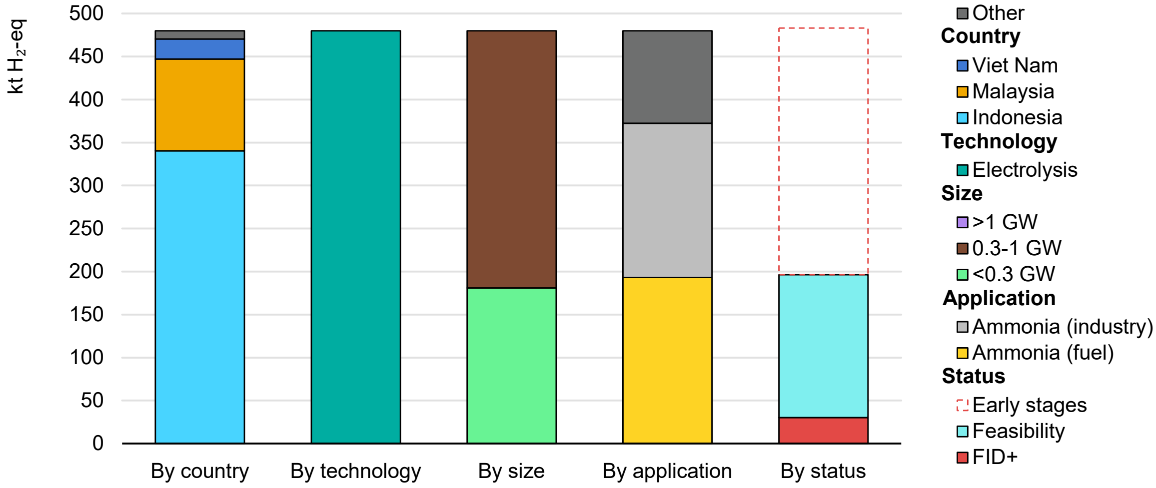
Such a highly concentrated pipeline may reduce the potential for experimentation with different configurations, users and stakeholders. Relying on a few large projects makes execution more complex, with a bigger risk of missing the starting dates if unexpected events arise. The pipeline is currently lacking mature projects at the scale of 50-250 MW that could serve as a stepping stone for the giga-scale projects. While there are several such projects, they will not be ready to come online in the next few years.

The outlook is different when considering the full project pipeline including projects beyond 2030, which comprises 47 projects adding up to 5.7 Mtpa of production capacity. Seventeen projects, adding up to 5.2 Mtpa of production capacity, are still at the concept stage, without an announced date for starting operations and

[108] It is assumed that projects take a few years to reach full capacity. The 150 ktpa capacity for the project in Malaysia corresponds to several phases and only the first phase is considered for 2030.
[109] This timeline may be difficult to meet given that Indonesia does not have any operating nuclear capacity and first-of-a-kind projects can experience delays.

therefore highly speculative. The extended pipeline is dominated by electrolysis (with only three projects from fossil fuels with CCUS), and almost two-thirds are mega projects of more than 1 GW of electrolysis.

Figure 7.4 Breakdown of announced low-emissions hydrogen projects in Southeast Asia, 2030



Notes: FID+ = projects with a final investment decision, including those under construction. Only projects with a disclosed start year are included.

Announced low-emissions hydrogen projects in Southeast Asia total 12% of current regional hydrogen demand, but only 6% of announced capacity has reached FID.

Hydrogen production from renewables

Domestically produced renewable hydrogen offers an opportunity to take advantage of the region's vast renewable potential while decreasing reliance on imports. Notably, the region currently produces the majority of its hydrogen from natural gas and may transition from being a net gas exporter to a net gas importer in 2025, meaning it would need to either rely on natural gas imports or imports of hydrogen derivatives to satisfy growing hydrogen demand in the future. The opportunities associated with renewable hydrogen production could also extend to decreasing imports of hydrogen derivatives.

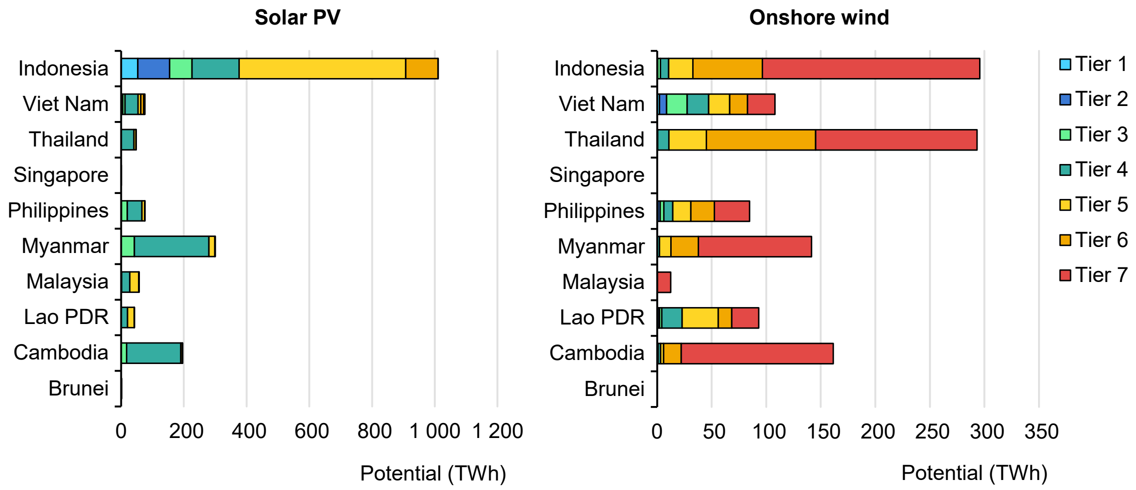
Deployment of renewables for hydrogen production would need to be balanced against aims to prioritise displacement of fossil fuels in the power sector, where renewable electricity has a larger mitigation effect.

Southeast Asia has a solar PV potential of more than 1 800 TWh, of which 93% has a capacity factor of more than 18% (Figure 7.5).[110] More than half of this

[110] Considering horizontal single-axis tracking.

potential is in Indonesia, with the largest share having a capacity factor in the range of 18-20%. Indonesia, Myanmar and Cambodia represent more than 80% of the regional potential. Potential in these three countries exceeds current electricity demand by a factor of 2, 13 and 12, respectively. For the rest of the region, solar PV potential is below current demand. Almost 60% of the region's potential would have an LCOE below USD 50/MWh, assuming an average capital expenditure (CAPEX) of USD 950/kW and a weighted average cost of capital (WACC) of 6-8.5%.[111]

Figure 7.5 Constrained technical potential for solar PV and onshore wind by Southeast Asia country



Notes: Resources are grouped by capacity factor with clusters of 2% for solar PV (Tier 1 is more than 26% and Tier 7 is less than 16%) and 5% for onshore wind (Tier 1 is more than 40% and Tier 7 is less than 15%). Potential is constrained by land exclusion zones, so not all the land is available for variable renewables. Solar PV with horizontal single-axis tracking. Weather data from 2018. This only looks at the supply perspective and does not include, for example, potential grid integration issues that renewables could face once assets are constructed (since that would vary over time and requires broader power modelling).

Source: IEA analysis based on data from Jülich Systems Analysis at Forschungszentrum Jülich using the ETHOS model suite.

Southeast Asia has a solar PV potential of more than 1 800 TWh and a more restricted onshore wind potential of 110 TWh with a capacity factor higher than 25%.

For onshore wind, the potential is much lower than for solar PV given that the resource quality is poorer. The total potential is nearly 1 200 TWh. However, less than 10% of such potential has a capacity factor higher than 25%. This potential with a high capacity factor is more evenly distributed, with five countries having more than 10% of the potential. This wind potential could cover at most 45% of

[111] Current CAPEX based on IRENA (2024), NREL (2020), IEA (2024), BNEF (2023), OECD (2024). Current WACC based on IEA (2023), IRENA (2024). Values are for 2030 assuming deployment following stated policies.

current electricity demand in Lao PDR, and a lower share in other countries. With an average CAPEX of USD 1 900/kW and the same WACC of 6-8.5%, just over 20% (corresponding to 25 TWh/yr) would have an LCOE below USD 75/MWh.

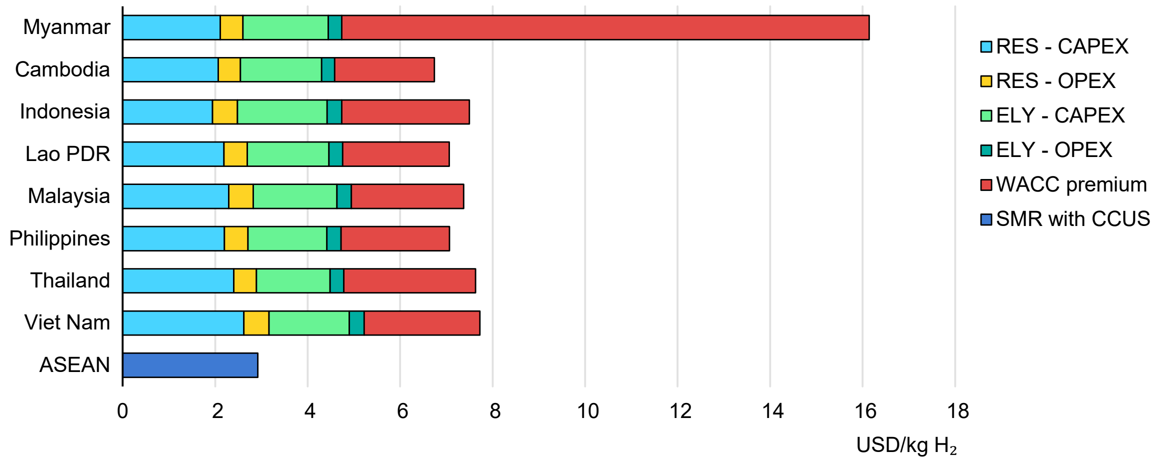
Similarly, the offshore wind potential in Southeast Asia is relatively poor. The Philippines and Viet Nam are the only countries in the region that have more some potential with a capacity factor higher than 35%. As a point of comparison, the existing capacity in Viet Nam has an average capacity factor of just 37%. Viet Nam has 365 TWh of potential above this threshold, while the Philippines has 25 TWh. One of the main challenges is the cost: CAPEX estimates for offshore wind in Viet Nam in 2023 were nearly USD 3 700/kW. This could be reduced by 10-30% by 2030 (depending on deployment), but it would remain relatively expensive to be competitive for hydrogen production. To become competitive, both the high CAPEX and the high cost of capital would need to be addressed. For electricity, Viet Nam targets a capacity expansion to 6 GW by 2030 (compared to 1.1 GW in 2023).

There are also opportunities in renewables beyond solar PV and onshore wind. For example, Lao PDR already has almost 10 GW of hydropower capacity and has an estimated potential of 26 GW. Lao PDR plans to export part of this potential via cross-border transmission lines to China, Cambodia, Malaysia, Thailand and Viet Nam. Renewable hydrogen could be an alternative to tap into new markets with a different risk profile, and access markets that are further away than would be economically feasible to cover with cables. In 2023, Indonesia accounted for nearly one-sixth of global geothermal generation, and has a total technical potential of more than 2 000 GW[112] (for a depth of 5 000 metres).

For renewable hydrogen, the main factors determining the cost are the electricity cost and the investment for the electrolyser, while the carbon price and the gas price influence its competitiveness with gas-based routes. Southeast Asia has relatively high capacity factors for solar PV (less so for onshore wind), and the main cost barrier is the high WACC. This affects not only hydrogen production but also renewables for electricity, since both are capital-intensive assets (Figure 7.6). For example, Viet Nam, where most of the region’s renewable deployment is today, had a WACC of 6-7% (in real terms) for solar PV and onshore wind in 2023. Similarly, Indonesia, which has the largest total generation in the region, had a WACC of 5-8% for the same year. In contrast, China, which is the largest renewables market in the world, had a WACC of 3% in 2023.

[112] For a hydrothermal system installed at a depth of up to 5 000 metres and a LCOE threshold of USD 200/MWh. Potential could increase by another 1 650 GW if enhanced geothermal systems are considered.

Figure 7.6 Levelised cost of hydrogen production in Southeast Asian countries, 2023



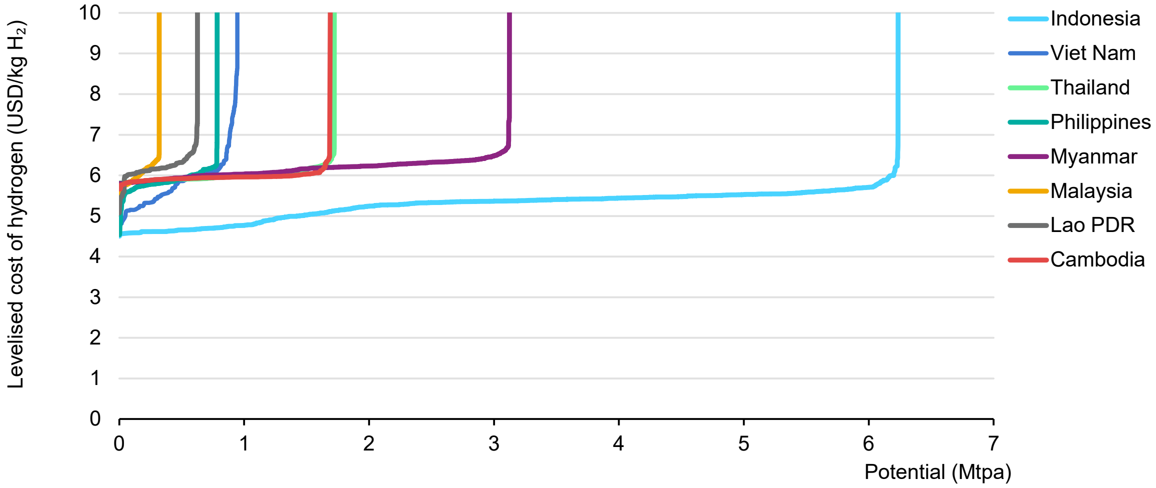
Notes: RES = Renewables; ELY = Electrolyser; CAPEX = Capital expenditure; OPEX = Operational expenditure; WACC = Weighted Average Cost of Capital; SMR = Steam methane reforming; CCUS = Carbon capture, utilisation and storage. WACC premium is shown in comparison to China, as a major renewable market in the Asia region, with a 3% WACC. Hydrogen production is based purely on solar PV since it constitutes the largest share of renewable potential. Brunei and Singapore are excluded given their limited domestic renewable potential. Solar PV capacity is assumed to be three times larger than the electrolyser.

Sources: IEA analysis based on IEA (2024), Achieving a Net Zero Electricity Sector in Viet Nam; ICL and IEA (2023), ASEAN Renewables: Opportunities and challenges; IRENA (2024), Renewable Power Generation Costs in 2023; NREL (2020), Exploring Renewable Energy Opportunities.

Cost of capital is a major cost driver, increasing the levelised cost of hydrogen production by 45-55% in comparison to a case where cost of capital is 3%.

Renewable potential and cost can be combined to estimate supply cost curves. This considers the geographical variability of resource quality and the increase in production cost as the sites with the highest capacity factors are used. This also allows for the application of an economic criterion to constrain the technical potential and therefore be closer to what could be used in reality. In a future where technology deployment follows the current policies in force and cost of capital in the region remains as it is today, Southeast Asia could have nearly 11 Mtpa of renewable hydrogen potential below a production cost of USD 6/kg H_2 by 2030 (Figure 7.7). This does not mean that such production will be achieved by 2030, rather it represents an upper bound. Indonesia accounts for almost 60% of this potential, followed by Cambodia and Thailand with 13% and 10% respectively. In comparison to current hydrogen demand, the potential supply in Indonesia, Philippines, Thailand, Viet Nam at this cost level would be higher than demand. With these cost assumptions, no hydrogen could be produced at a cost lower than USD 4.5/kg H_2.

Figure 7.7 Supply cost curves for renewable hydrogen in Southeast Asian countries, 2030



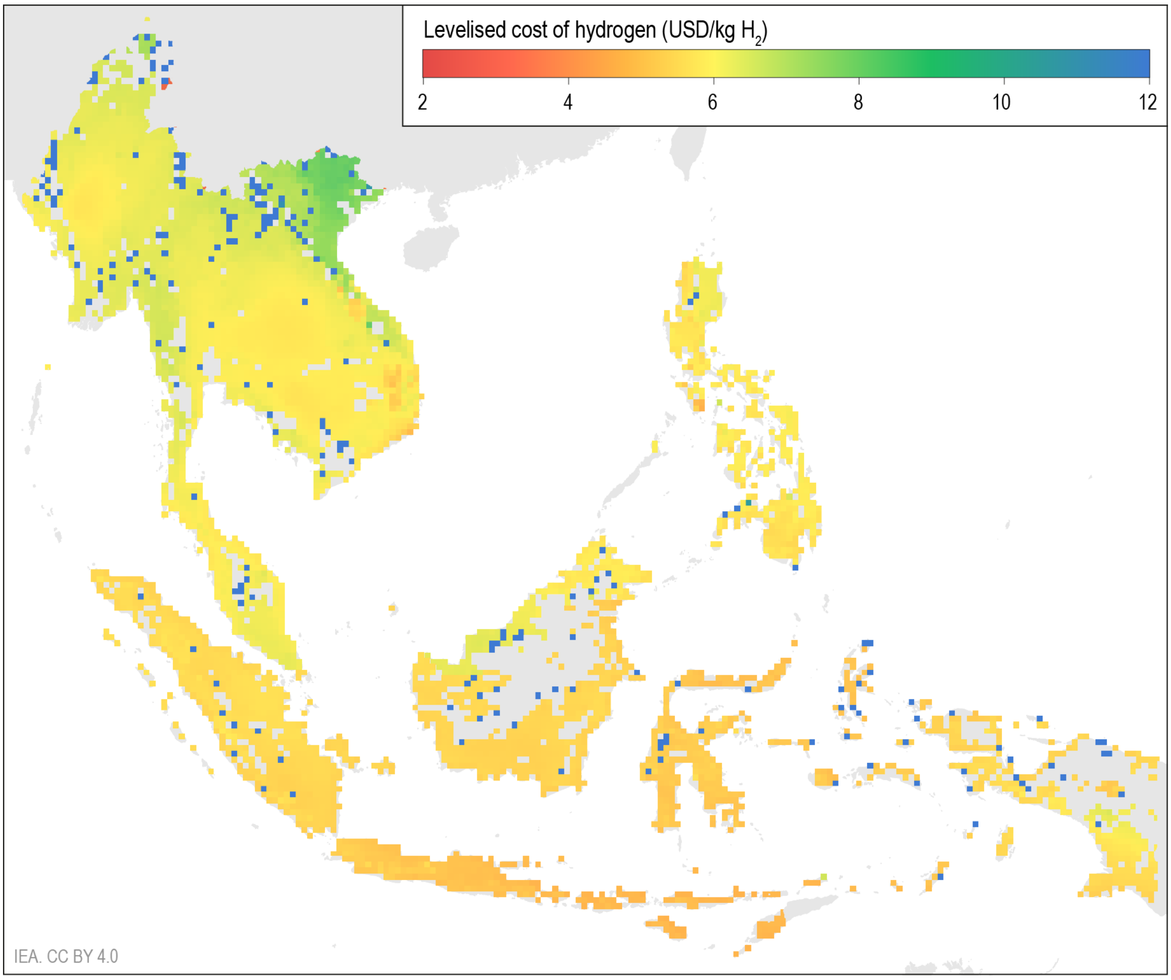
Notes: Based on cost optimal configurations based on solar PV and onshore wind. Potential shown in the figure is restricted to 25% of the technical renewable potential. Cost evolution to 2030 based on technology deployment in the Stated Policies Scenario (STEPS).

Source: IEA analysis based on data from Jülich Systems Analysis at Forschungszentrum Jülich using the ETHOS model suite.

Southeast Asian countries could have nearly 11 Mtpa of hydrogen potential at a production cost below USD 6/kg by 2030.

More than 90% of the renewable hydrogen that can be produced below USD 5.5/kg H_2 is in Indonesia, concentrated in Java, Kalimantan, Sumatra and Sulawesi (Figure 7.8). The bulk of the potential comes from solar PV and those regions benefit from the highest solar irradiation in Southeast Asia. The supply cost curves are relatively flat (Figure 7.7), so some potential is available at a relatively small cost premium. At USD 6/kg H_2, more than 0.5 Mtpa of potential is unlocked in each of the following countries Cambodia, Myanmar and the Philippines.

Figure 7.8 Hydrogen production cost from hybrid solar PV and onshore wind in Southeast Asian countries, 2030



Notes: Based on cost optimal configurations based on solar PV and onshore wind. Potential shown in the figure is restricted to 25% of the technical renewable potential. Cost evolution to 2030 based on technology deployment in the Stated Policies Scenario (STEPS).

Source: IEA analysis based on data from Jülich Systems Analysis at Forschungszentrum Jülich using the ETHOS model suite.

More than 90% of the renewable hydrogen that can be produced below USD 5.5/kg H_2 is in Indonesia concentrated in Java, Kalimantan, Sumatra and Sulawesi.

Hydrogen production from nuclear power

There is renewed interest in nuclear in Southeast Asia, but hydrogen production is not currently a key consideration

There is no nuclear capacity in Southeast Asia today, but interest in nuclear energy is resurging across the region, driven by energy security concerns, decarbonisation targets, energy demand growth and technological advances. Notably, small modular reactors (SMRs) are gaining attention due to their advantages compared to large-scale reactors, including lower investment costs, enhanced safety features, flexible generation possibilities and reduced grid disruption.

Indonesia, which has maintained a regulatory framework and research capacity since the late 1990s, is now accelerating efforts to develop its first nuclear power plant. The country's most recent electricity supply plan (2025-2034) targets two 250-MW reactors by 2032, and its net zero roadmap envisages 9 GW of nuclear capacity by 2060.

The Philippines is actively reassessing nuclear energy's role in its power mix. It remains the only country in the region to have built a nuclear power plant, the Bataan plant, completed in the 1980s but never commissioned. The government has since explored both the rehabilitation of this facility and the development of new capacity, targeting 4.8 GW of nuclear by 2050.

Malaysia shut down its nuclear programme in 2018, but started re-exploring it in 2022 with a view to incorporating nuclear in its energy mix after 2035.

Thailand has included SMRs in its long-term energy outlook and is taking steps to reinitiate planning for civilian nuclear power, including a regulatory review of the relevant legal frameworks that began in December 2024.

Singapore is building up technical and institutional capabilities to support long-term decision-making, including workforce development in nuclear science and engineering.

The 8th ASEAN energy outlook (from 2024) estimates that nuclear could meet 0.2-2% of regional electricity demand in 2050. However, despite growing interest, nuclear deployment in the region still faces challenges and previous waves of interest have not led to real-world investment. For example, Indonesia had earmarked USD 8 billion to reach 6 GW of operating capacity by 2025, but cancelled those plans in 2015. In 2006, Viet Nam defined targets of 2 GW of nuclear capacity by 2020 increasing to 8 GW by 2025, and in 2009 approved the construction of two 2 GW plants, but in 2016 plans were indefinitely postponed. Public acceptance across the region varies, and is lower than for other clean technologies. None of the Southeast Asian countries endorsed the COP 28 declaration aim of tripling nuclear energy capacity globally by 2050. While regional co-ordination on nuclear governance, safety standards and infrastructure development is gradually growing (through bodies including the ASEAN Sub Sector Network on Nuclear Energy and ASEAN Network of Regulatory Bodies on Atomic Energy), ASEAN has not yet developed shared frameworks on nuclear energy, which may exacerbate cross-border sensitivities. Public acceptance is therefore not only a domestic issue but also a regional one. Furthermore, there are no international regulations related to governance and deployment of SMRs.

Hydrogen has not been a key consideration of nuclear development plans, and nuclear remains a relatively expensive electricity source for hydrogen production. If Southeast Asian countries were to reach the capital costs observed in China (USD 2 500/kW), which are nearly 45% lower than in the European Union, the cost of electricity alone would be equivalent to USD 2.8-4.5/kg H_2. This is without considering the CAPEX for the electrolyser. nuclear is a capital-intensive technology, so reducing the cost of capital will be critical.

Hydrogen production from natural gas

Hydrogen production from natural gas with carbon capture is cheap but could lead to higher reliance on gas imports

Hydrogen production from natural gas has two main advantages: a lower cost than renewable hydrogen, and the possibility to use existing assets by adding a carbon capture unit. Nearly 80% of the hydrogen demand in Southeast Asia is currently satisfied with hydrogen produced from natural gas, and many of these production assets are relatively young. For a greenfield design, which allows the optimal integration of the reforming and capture units, adding a carbon capture unit with a 90% capture rate to a steam methane reformer can result in almost 80% higher capital cost and 33% higher operating cost. For a retrofitted plant, costs are likely to be higher, and operational downtime is required for installation. Despite this cost premium, production from natural gas with carbon capture is still less than half the cost of the cheapest renewable hydrogen in Southeast Asia (Figure 7.6).

There are significant efforts on CCUS infrastructure, policy and regulation in the region. Indonesia and Malaysia[113] are the frontrunners planning to become regional CO_2 storage hubs[114], and both countries already have legislation in place covering permitting, storage, liabilities, hubs, among other aspects, as well as tax incentives. Thailand has tax incentives in place and together with the Philippines has several oil and gas legislations that could be adapted to regulate CCUS. Meanwhile, efforts in Viet Nam are mostly focused on R&D, while Singapore is planning to develop a 2.5 Mtpa CO_2 storage hub by 2030. Six countries (Brunei, Indonesia, Malaysia, the Philippines, Thailand and Viet Nam) have performed an initial assessment of CO_2 storage potential, with an estimated 220 Gt of storage potential with around 98% of this potential in saline formations. This would be enough to store over 100 years of CO_2 emissions at current levels. There might

[113] In March 2025, Malaysia passed the CCUS Bill, which covers Peninsular Malaysia, while Sarawak has its own legislation, the Land (Carbon Storage) Rules from 2022.
[114] Malaysia is planning to develop three CCUS hubs by 2030 with a total storage capacity of 15 Mtpa.

also be an opportunity to create economies of scale with carbon capture on existing coal plants. Indonesia, Malaysia and Viet Nam have low-emissions hydrogen production from natural gas in the long-term production mix (see Policy landscape), highlighting an opportunity to close the gap between what is being done today and future expectations.

There is extensive regional collaboration on developing CCUS. At the regional level, the CCS Deployment Framework and Roadmap, which is recognised by local governments, defines actions across three phases (until 2050) with five strategies to address CCUS challenges and accelerate the readiness level of associated technologies. These comprise enhancing economic viability, reducing lead times, derisking deployment, innovation, and cross-border CO_2 transport. Governments in the region also recognise the importance of facilitating cross-border CCUS projects. Malaysia has at least 24 Memoranda of Understanding (MoUs) with 9 countries including Japan, Korea and Singapore. Indonesia also has multiple MoUs, including with Japan and Singapore. Collaboration between ASEAN countries and Japan is also taking place under the Asia Zero Emissions Community (AZEC).

There are, however, some challenges to be considered. In 2024, Southeast Asia exported 15% of the nearly 175 bcm of gas it produced, but under today's policy settings, the region could become a net importer by 2025. Additional gas demand for hydrogen production would therefore rely on additional gas imports. Another challenge is the time associated with building infrastructure and storage capacity and finalising the regulatory framework, which means it will take time for CCUS deployment to make a meaningful contribution to low-emissions hydrogen production.

In terms of project pipelines, there are 14 carbon capture projects in the region with a total CO_2 capacity of more than 12 Mtpa. Two of these projects (one in Malaysia and one in Indonesia) are under construction, for which the period from announcement to operation is expected to last at least 6-8 years. The first CCUS project is expected to start by the end of 2025. There are also three hydrogen-related projects in early stages of development in Indonesia.[115] Out of 47 low-emissions hydrogen projects in the pipeline, just 3 are for production from natural gas with CCUS, none of which have a commercial operating date before 2030.

Opportunities in hydrogen demand sectors

The main opportunities to use low-emissions hydrogen in Southeast Asia lie in the existing hydrogen applications. Ammonia, in particular, offers the possibility to reduce emissions from current hydrogen uses and displace imports, enhancing

[115] 1.4 Mtpa in the Balikpapan Refinery, an ammonia plant in Banggai, an ammonia plant in Sumatra-Java.

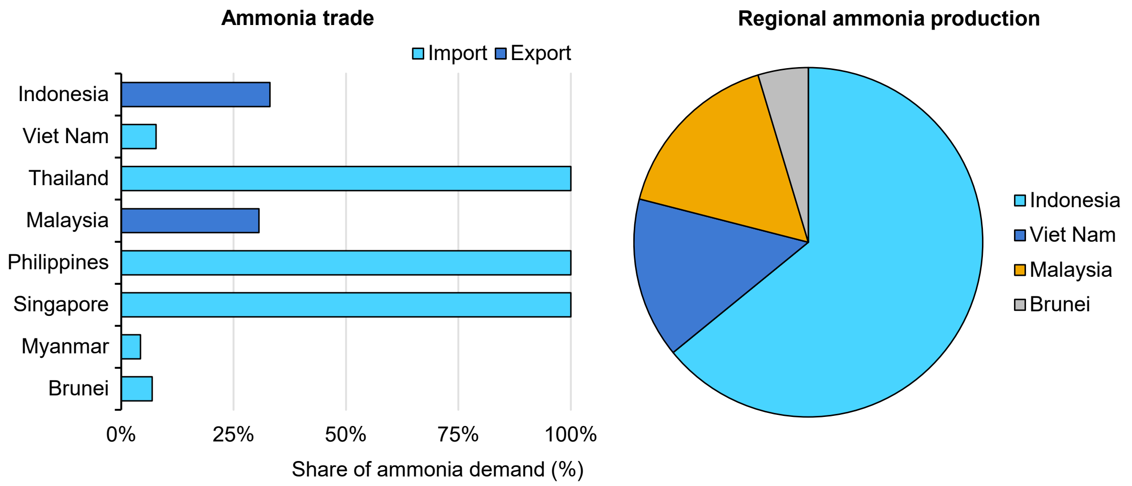
energy security. Thus far, there have been limited policy incentives across the region to decarbonise industrial applications, and more public support is needed to promote a fuel shift. Demand for both existing and new hydrogen applications is largely concentrated, meaning there is an opportunity to make a large impact by focusing on a few sites.

Low-emissions ammonia

Indonesia, Malaysia and Viet Nam have a large demand today while Thailand could displace ammonia imports

In 2023, ammonia represented nearly half of regional hydrogen demand, providing a natural starting point for low-emissions production. Southeast Asia produced 11.1 Mtpa of ammonia, while demand reached 9.5 Mtpa. Almost all ammonia production relies on fossil fuels, and a third of the production capacity has been in operation for less than 10 years. The largest surplus is in Indonesia, which produced 7.1 Mtpa across 5 plants and exported a quarter of its production. The next largest markets are Malaysia and Viet Nam, producing 1.8 Mtpa and 1.6 Mtpa, respectively. Malaysia exports a quarter of its production, while Viet Nam needs additional imports to satisfy 8% of its demand (Figure 7.9). Contrastingly, Thailand, Singapore and the Philippines do not have any domestic ammonia production, and all of their demand is met by imports.

Figure 7.9 Ammonia production, demand and trade by Southeast Asian country, 2023



Source: IEA analysis based on data from the International Fertilizer Association.

The largest Southeast Asian markets are close to being self-sufficient or are exporters, while the smaller markets are fully dependent on imports.

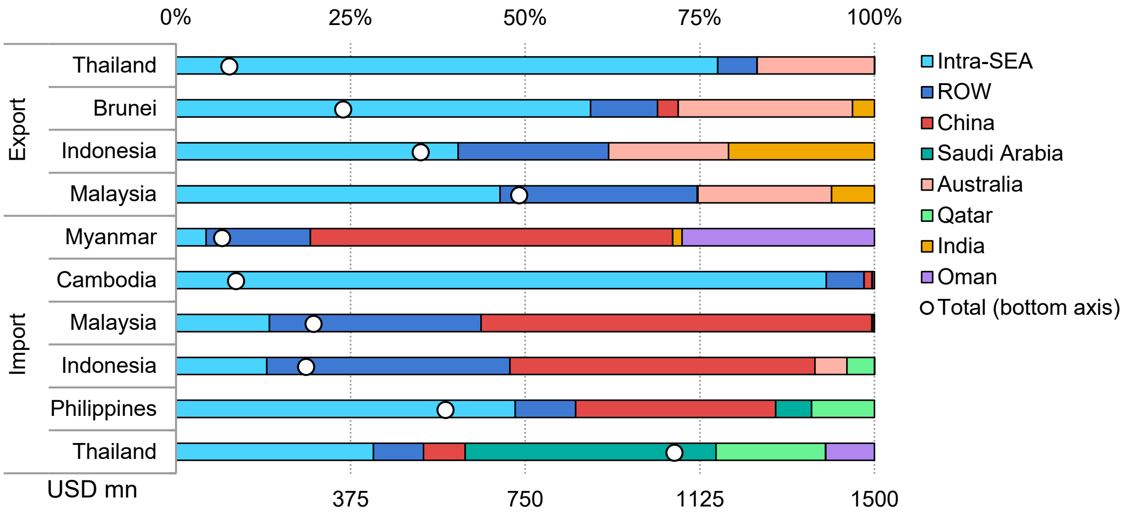
Among importers, Thailand has the greatest opportunity for domestic low-emissions ammonia production, since the Thai market is large enough to provide economies of scale. The nearly 340 ktpa of ammonia demand in Thailand would be equivalent to a project with an electrolyser size of 650 MW.[116] This would be enough to achieve economies of scale and low production costs. Today, there is no electrolyser capacity in the project pipeline to 2030 in Thailand. Beyond that, there is one Memorandum of Understanding (MoU) between ACWA Power (a leading developer), PTT (Thailand's national integrated energy company) and the Electricity Generating Authority of Thailand (a state-owned power utility) signed in 2022 for a 1.2 Mtpa ammonia plant with a total investment need of USD 7 billion, though there have been no updates since then. Ammonia is mostly used by the fertiliser industry; about 45% of fertiliser demand is met with nitrogen-based fertilisers.

In Thailand, the main barrier to producing renewable ammonia domestically is the cost of capital. Ammonia has a relatively low transport cost, meaning that it is cheaper to produce renewable ammonia in places with high capacity factors for renewables and a low cost of capital, even if transport is then required, than it is to produce it domestically in locations that do not benefit from these enabling factors. For example, shipping ammonia over 5 000 km (a representative import distance from Australia) would imply a cost penalty of about USD 25 per tonne of ammonia (t/NH_3). This is equivalent to about 0.35 percentage points of WACC. In 2023, the real (after tax) WACC in Thailand was 6.6% for solar PV, compared to 4.3% in Australia. This means that it would be cheaper to import ammonia from Australia than to produce it domestically. However, this needs to be weighed against other criteria like reducing import dependency and enhancing food security, economic activity or job creation, which might still justify domestic production.

Looking more broadly at trade of nitrogen-based fertilisers[117] in Southeast Asia, the bulk of trade is intra-regional (Figure 7.10). In 2023, about 45% of the exports were for intra-regional trade, almost one-fifth is exported to Australia and 10% to both India and Mexico. With regards to imports, a third of the trade is intra-regional, followed by imports from China, which make up nearly a quarter, and from Saudi Arabia, with 17%. Thailand has the largest net imports in the region, and it also has the most diversified supply, though 90% of its imports come from six countries. About 60% of the fertiliser demand in Thailand is satisfied with nitrogen-based compounds. In terms of value, in 2023, the regional imports were equivalent to USD 2.5 billion, while exports reached USD 1.7 billion. As a point of reference, the global market for fertiliser trade was nearly USD 100 billion in 2023.

[116] Assuming an electrolyser efficiency of 60% on lower heating value basis and 5000 operating hours a year.
[117] Ammonia, urea, ammonium nitrate, calcium ammonium nitrate, urea ammonium nitrate.

Figure 7.10 Main trading partners for nitrogen-based fertilisers in Southeast Asia, 2023



Notes: SEA = Southeast Asia; ROW = Rest of world. Based on HS Code 3102 (Mineral or chemical nitrogenous fertilisers).
Source: IEA analysis based on COMTRADE.

Most of exports of nitrogen-based fertilisers remain within the region, while China is the largest source of imports from outside Southeast Asia.

Low-emissions methanol

Low-emissions methanol could displace imports in Indonesia and Thailand and offer export opportunities for Malaysia

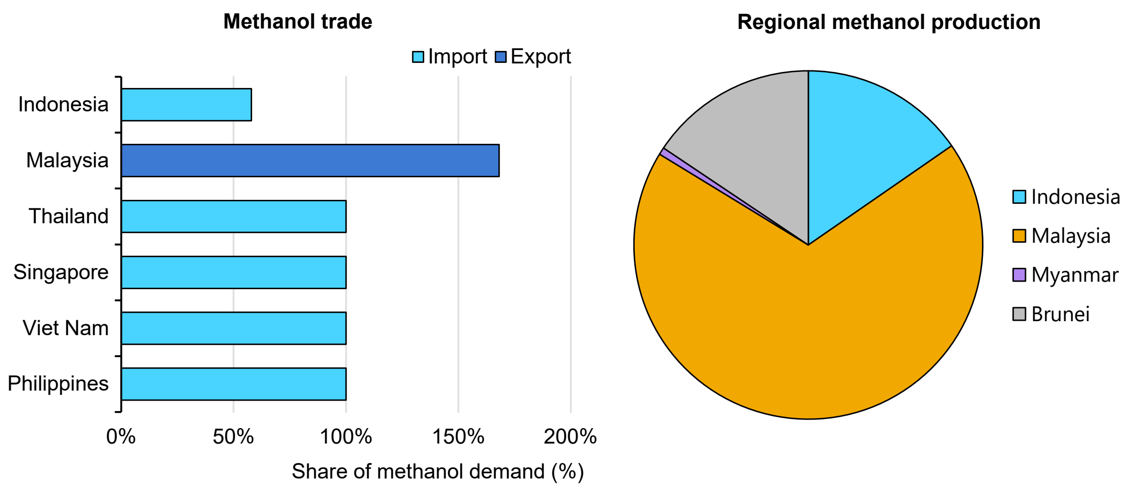
Today, methanol represents about 20% of regional hydrogen demand. Southeast Asia produced nearly 4.2 Mtpa of methanol in 2024, equivalent to 3.5% of global production, and demand reached 4.3 Mtpa, making the region a net importer. Half of the region's methanol production capacity came online after 2018. Malaysia represents over two thirds of the regional production. Until 2024, the market had been dominated by a Malaysian state-owned enterprise, Petronas Chemicals, which had two plants in Labuan with a combined installed capacity of 2.4 Mtpa, and a 70 ktpa plant in Kedah. The largest plants are relatively old, at 41 years for the 0.75 Mtpa plant in Labuan, 26 years for the small plant in Kedah, and 16 years for the largest plant in Labuan. In 2024, another state-owned enterprise, Sarawak Petchem, started a 1.75 Mtpa plant in Bintulu, following 5 years of construction. Petronas Chemicals has not defined a specific decarbonisation strategy and follows the targets defined by its parent company (see State-owned enterprises). It is not directly involved in any renewable methanol projects. Sarawak Petchem's decarbonisation plans are aligned with those of the regional government, which target 15 GW of renewable energy by 2035 (vs a current total capacity of 5.7 GW, of which 3.4 GW are from hydropower). This could both meet regional demand,

and create export opportunities, such as to Singapore. Hydrogen derivatives – including methanol – could also form part of the exports. In early 2025, the company trialled shipping 20 kt of methanol to China and started constructing a pilot plant in Bintulu, with a view to using methanol as a shipping fuel in the Japanese market.

Indonesia is the region's second-largest methanol producer, with about 660 ktpa in a single plant operated by a private company (PT Kaltim Methanol Industri). A state-owned enterprise (PT Pupuk Indonesia) has plans to develop two other methanol plants by 2030 using production from unabated natural gas.

Satisfying methanol demand with domestic production can be resource intensive. For example, meeting 25% of the current demand with renewable methanol would require about 2.2 GW of electrolysis and 1.5 Mtpa of CO_2. Meanwhile, the entire solar PV generation capacity in Malaysia in 2024 was 2.3 GW, and 1.5 Mtpa of CO_2 is roughly double the energy-related emissions from Indonesia, the country with the largest emissions in the region. As methanol demand increases, consideration of the resource needs is expected to become only more important.

Figure 7.11 Methanol production, demand and trade by Southeast Asian country, 2024



Notes: Brunei is not shown in the figure on the left because trade is expressed as a share of ammonia demand and nearly all of its production is exported (i.e. there is hardly any demand).
Source: IEA analysis based on Argus Methanol Analytics, Argus Media Group, All rights reserved,.

Southeast Asia is a net methanol importer, driven by demand in Indonesia, Thailand and Singapore, while Malaysia and Brunei are heavily export oriented.

There are big differences between countries in terms of methanol imports (Figure 7.11). Indonesia represents a third of regional demand and meets over 60% of that demand with imports. Malaysia only uses about 40% of its production for the domestic market and the rest is exported, while Brunei exports nearly all its production. Other countries in Southeast Asia with sizeable demand are the Philippines, Singapore, Thailand, Viet Nam, which are entirely reliant on imports. Of these, only Thailand has demand large enough today to provide economies of scale with enough domestic renewable potential.

Refining

Existing policies do not address decarbonising refineries, creating an opening for measures targeting fuel shifting

Hydrogen demand from refining in Southeast Asia was 1.3 Mtpa in 2024. The region holds nearly 5.5 Mbpd of refining capacity, equivalent to 5% of global refining capacity, across 30 refineries, with a throughput of 3.9 Mbpd in 2024. Singapore alone has nearly 30% of the regional capacity in just 3 refineries.[118] Singapore, Indonesia and Thailand together account for almost 70% of the regional capacity. The refineries in Indonesia are operated by the national oil company (Pertamina), while those in Singapore are a mix of joint ventures and operation by foreign companies. The refineries in Indonesia and Thailand mostly serve their domestic markets, whereas Singapore exports most of its refining output with a large share used for international bunkering.

In **Singapore**, refining represents about one-fifth of national CO_2 emissions from fuel combustion. The country's 2022 hydrogen strategy did not specify actions to decarbonise use in refineries, and none of the eight renewable hydrogen projects in Singapore are in refineries. The industrial sector is covered by the carbon tax which is USD 19/t $CO_{2\text{-eq}}$ in 2025 increasing to USD 35/t CO_2 in 2026. However, this alone would not be enough to cover the cost premium of using (imported) renewable hydrogen. The industrial policies in place target energy efficiency, and do not yet promote steps towards fuel shifting. CCUS is part of the industrial decarbonisation strategy, and there are efforts to capture 2.5 Mtpa of CO_2 by 2030, but given that Singapore has limited storage capacity, the CO_2 would potentially be exported to other countries. The pace at which this infrastructure can be built might be a constraint in early years of development, meaning that other emission sources might be given a higher priority to use this limited capacity, ahead of refining. None of the refineries' operators have public decarbonisation plans.

In Indonesia, existing industrial policies focus on energy efficiency and there are no policies to promote fuel shifting as yet. In 2023, Indonesia launched an ETS, initially covering coal power generation. In 2025, the government announced plans

[118] ExxonMobil's two operating sites (one in Jurong and one in Pulau Ayer Chawan), which are connected by pipelines and have operated as an integrated asset since Exxon and Mobil merged in 1999, are counted as one refinery.

to expand coverage to selected industrial sectors by 2027, but this did not include refining. Furthermore, the average price in the secondary market in 2023 was less than USD 5/t CO_2.

Looking to the future, there is uncertainty about oil demand; the size of any reduction will depend on the level of electric vehicle penetration across transport modes and the extent of oil use as a chemical feedstock. For example, in a scenario following stated policies, oil demand could increase by 30% by 2050. In contrast, in a scenario achieving carbon neutrality by 2050, oil demand would be slashed by nearly 70% over the same time horizon.

Steel

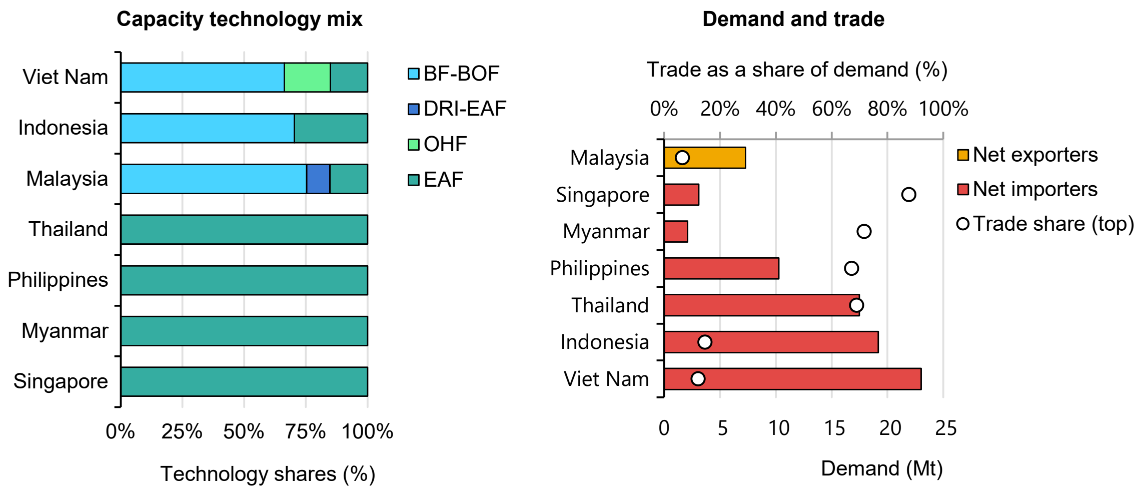
H_2-direct reduced iron could satisfy part of expected regional demand growth and displace imports in some countries

Crude steel production in Southeast Asia was over 51 Mt in 2023, which is less than 3% of the global total. With demand for 82 Mt, the region is currently a net steel importer. Indonesia and Viet Nam represented 70% of regional production, and in both countries, over two-thirds of the steel is produced via the primary route of blast furnaces (Figure 7.12). In Indonesia, the remaining 30% is produced with electric arc furnaces (EAF), while in Viet Nam almost 20% of the production comes from open hearth furnaces. The blast furnaces in both Indonesia and Viet Nam are relatively young, with an average lifetime of just 6-7 years.

The rapid economic growth of the region is expected to result in increased steel demand, which will require either the construction of new steel plants or increased reliance on imports. This means that production from existing assets will gradually represent a smaller share of the total. Secondary production, using scrap steel, is constrained by the availability of scrap. This could provide an opportunity for hydrogen-based direct reduced iron (H_2-DRI) to satisfy part of the expected demand growth. However, looking beyond Southeast Asia, part of this growth could be satisfied using excess capacity in China, where over half of the current global production is located – and where demand is expected to shrink over time. Another opportunity could arise from the use of hydrogen blending in existing blast furnaces, but that only results in partial decarbonisation, as blast furnaces cannot be entirely switched to pure hydrogen. Indonesia is already exploring the use of hydrogen for decarbonisation of the steel industry.

Malaysia and Thailand are the region's other steel producers, with 25% market share. Malaysia is the only Southeast Asian country that has some existing DRI capacity using natural gas (0.7 Mtpa, representing about 10% of production) at two locations (Kemaman and Labuan). Production has halved since 2013 but it could more than quadruple once a 2.5 Mtpa plant currently under construction starts operations in 2027. Thailand and the other countries with smaller amounts of production capacity are predominantly scrap-based EAF systems, and H_2-DRI would not displace EAF, rather, it could provide low-emissions iron that can be used along with scrap in EAFs, potentially reducing reliance on imported scrap or finished steel. A 2 Mtpa DRI plant is planned to start operations in Thailand in 2027. The plant will initially use up to 25% renewable hydrogen, with plans to ramp up to 100% renewable hydrogen use and export of certified low-emissions steel in the future.

Figure 7.12 Technology mix, production and demand in steel-producing countries in Southeast Asia, 2023



Notes: BF = Blast Furnace; BOF = Basic Oxygen Furnace; DRI = Direct reduced iron; EAF = Electric Arc Furnace; OHF = Open Hearth Furnace.
Sources: IEA analysis based on OECD steel capacity and World Steel Association.

All Southeast Asian countries except Malaysia are net steel importers, with an opportunity for H_2-DRI to help to close the trade deficit.

Southeast Asia is a net steel importer, but the national shares of imports are very different. For the largest producers, import shares are relatively small, at about 10% for Indonesia and 15% for Viet Nam. Thailand, which has a market of similar size to Indonesia, meets only 30% of its demand with domestic production from EAF. The smaller markets, Myanmar, the Philippines and Singapore, all rely on import shares of more than 75% to meet demand. These countries would need to move up in the value chain and start producing iron in addition to steel. As a point of reference, 1 GW of electrolysis, which might be enough to achieve economies of scale with low CAPEX, would be enough to produce about 1.5 Mtpa of steel[119]. Myanmar and Singapore would need two of these plants to satisfy their entire demand; the Philippines would need seven and Thailand twelve.

Southeast Asia is also a net iron ore importer. Regional iron ore production was nearly 15 Mtpa in 2023, which means nearly three-quarters of the primary steel production in the region is reliant on iron ore imports, although this differs by country. Iron ore production in Viet Nam has decreased by over 75% since 2019, meaning that nearly 90% of the primary steel production relied on imports in 2023. Among steel-producing countries, Malaysia has the largest iron production, with 4.8 Mtpa in 2023, but still needs to import iron ore. The region's largest iron ore exporter is Lao PDR, which has no domestic iron and steel production, but produced nearly 4.5 Mtpa of iron ore in 2023. Iron ore production in Lao PDR expanded by nearly ten times in just 4 years (from 2019 to 2023), driven by government incentives like tax breaks, lease incentives and faster approval processes, which aim to increase revenues from the mining sector to address inflation and improve the fiscal deficit. The exports have not been used to improve the regional imbalance – instead, nearly all go to China.

Southeast Asia holds iron ore reserves of more than 5 Gt, which corresponds to about 3% of the global reserves. Indonesia alone has 2.9 Gt and two regions (Sulawesi and Sumatra) hold nearly two-thirds of the national reserves. About 45% of the reserves are in the form of laterite (which can also be found in the Philippines), which also contains nickel. Laterites have a lower iron grade, meaning they require upgrading,[120] but their nickel content could be useful for producing stainless steel (which represents about 3% of global steel production) or other nickel-containing alloys. Most of the reserves have an iron content of less than 60%, which is lower than the 67% needed for H_2-DRI. One solution to deal with the lower iron content is beneficiation, a process to remove impurities, which is necessary to improve the quality but also adds a cost penalty.[121] Other solutions include the use of fluidised bed technology (which could avoid the need to use pellets), and an additional smelting unit to remove impurities via slag production. Viet Nam holds another 1.3 Gt of reserves, with half of them located in two sites: Thach Khe-Ha Tinh (544 Mt with average iron content of 58%) and Quy Xa (121 Mt with an average iron content of 52%). Thailand, which could benefit from H_2-DRI production, has limited iron ore reserves and limited iron ore production today, meaning that import dependence could, at most, switch from finished steel to iron ore.

[119] Assuming 5 000 operating hours a year and an electrolyser efficiency of 60% (based on lower heating value).
[120] Other disadvantages are high humidity (making drying necessary), and possible need for additional physical separation.
[121] The beneficiation premium can be about USD 7-8/t for every percentage point of increase in iron content.

Shipping

Significant regional demand is covered by ongoing decarbonisation efforts, largely driven by international policy

Shipping demand in Southeast Asia was about 2.5 EJ in 2024, equivalent to 13% of the total final energy consumption in the region. More than 85% of the total demand from international shipping is based in Singapore, while Indonesia leads the consumption for domestic shipping, with 55% of the demand dedicated to this use. The Port of Singapore is by far the port with the largest demand for bunkering fuel in the region – or indeed the world – with nearly six times the demand of the world's second-largest (Port of Rotterdam). It accounts for nearly a sixth of the fuel consumption for global shipping. The combustion emissions from the fuel bunkered at the Port of Singapore are more than 2.5 times larger than the country's national emissions. In the short term, hydrogen derivatives are too expensive for mass adoption in shipping, so biofuels provide an alternative for decarbonisation while these technologies scale up. In the longer term, as low-cost biomass supply decreases, hydrogen derivatives could complement biofuels to achieve higher shares of decarbonisation.

The emissions from international shipping do not fall under national jurisdiction and are overseen by the International Maritime Organization (IMO), which adopted a strategy for the reduction of GHG emissions in 2023. Following this, the Net-Zero Framework approved in 2025 gradually introduces an emission intensity standard and a GHG pricing mechanism (see Chapter 2 for more details), which will provide an incentive for (near-)zero emissions fuels and close part of the cost gap with fossil fuels. This framework should be in place by 2027, but the system to reward the use of zero-emission fuels has not yet been defined. Similarly, the full methodology for the IMO lifecycle emission guidelines and default factors are still to be finalised. IMO measures are technology agnostic, which introduces an uncertainty for stakeholders that may affect commitments for infrastructure, fuel supply and ship orders.

The Port of Singapore consumed 55 Mt of fuel in 2024 with over 190 000 vessel calls. The port pursues a multi-fuel strategy, using methanol in the next few years, ammonia to come online between 2027 and 2030 and hydrogen in the longer term. If the port pursues a similar target to the IMO (5-10% of alternative fuels by 2030), this fuel demand would be equivalent to 3% and 5% of global ammonia and methanol demand, respectively. However, at the global level, vessels using alternative fuels remain limited (see Chapter 2 for details). The port has recently performed tests for methanol bunkering, with 1 600 tonnes of methanol bunkered in 2024 and a technical standard for bunkering released in 2025, followed by a call for methanol suppliers. This attracted over 45 responses, with a final selection expected before the end of 2025 and fuel delivery from 2027. For ammonia, a trial was held in 2024 with a dual-fuel combustion engine, the technical standard for bunkering should be ready by 2025, and five consortia have been pre-selected for bunkering supply. The port currently has limited ammonia storage capacity, but the ongoing RfP (see Policy landscape) includes storage within the scope of the tender. Singapore is involved in 6 Green and Digital Shipping Corridors[122] to develop supply of zero-emission fuels between large ports, with the aim of ensuring supplies of alternative fuels and providing a common platform involving financing institutions. Other areas of the port's strategy to promote the use of zero-emission fuels are demand creation, financing, talent and skill development, and international collaboration. Demand aggregation is also being targeted for small volumes from several stakeholders (which will have a limited impact on total operating costs for shipping companies) that when cumulated can justify large-scale supply contracts. Some legal challenges arise due to competition, but initiatives such as the Zero Emission Maritime Buyers Alliance could help to address these. Singapore also launched the Maritime Singapore Green Initiative in 2011 to promote green shipping. In 2024, this initiative was expanded to promote the uptake of alternative fuels through port dues concessions,[123] which will be in place from 2025 to 2027, with the level of incentives dependent on the type of fuel.

Aviation

Synthetic fuel supply to a handful of airports could make a big difference in decarbonising a burgeoning market

Energy demand for aviation in Southeast Asia was nearly 670 PJ/yr in 2022. This is 6% of the global energy demand for aviation, which is similar to the 5% share the region has over the total energy demand. However, there are large discrepancies between countries; Singapore alone accounts for about a third of regional demand. When considering demand per capita, Singapore has nearly four times the demand of the United States and eight times the demand of Germany. Malaysia and Thailand, which represent almost a sixth of the regional population, align with the global average (Figure 7.13). All the other Southeast Asian countries, with a population of almost 580 million (equivalent to the population of the European Union and Japan combined) have demand that is well below the global average, and much lower than in advanced economies. If the entire population of Southeast Asia (i.e. 9% of the global population) were to reach a similar energy consumption per capita for aviation to Germany, the energy demand would be about 3 200 PJ/yr, or nearly a quarter of global energy demand

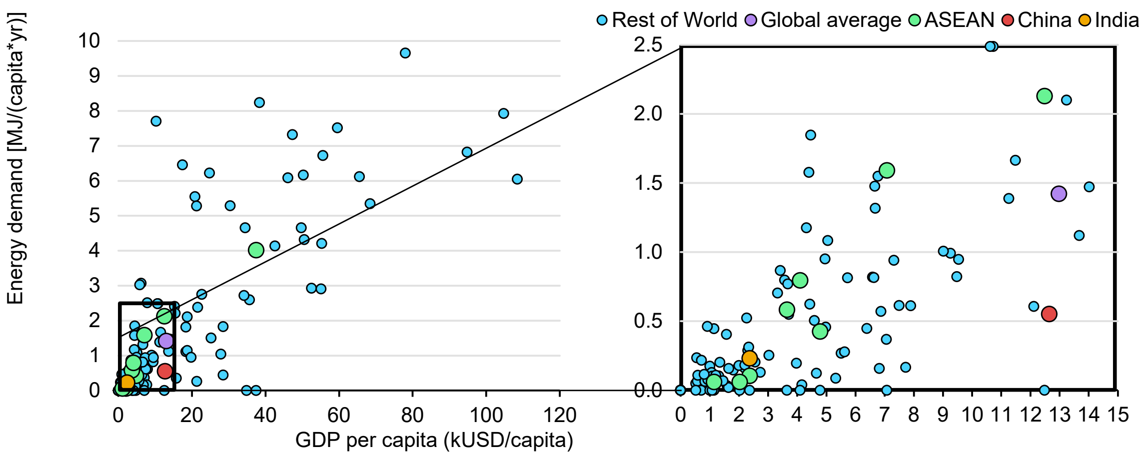
[122] Involving Australia, China (Shandong and Tianjin), Japan, the Netherlands (Rotterdam) and the United States (Los Angeles). Collaboration with the United Kingdom is through a public-private partnership and has not yet been formalised as a corridor.
[123] Initial registration fees, annual tonnage taxes and port fees paid for docking at the port.

for aviation. As a point of reference, satisfying just 10% of that demand with synthetic fuel would require 50-55 GW of electrolysis,[124] which is almost 25-28 times the global electrolysis capacity in 2024.

Energy demand for aviation is expected to increase as economic development continues. Some Southeast Asian countries already have an aviation decarbonisation strategy in place,[125] but most consider biofuels as an alternative fuel and blending targets remain aspirational or not yet in place.

One opportunity for the region is that the fuel demand in each country is largely concentrated in a few airports, meaning that supply of synthetic fuel to these airports would address the bulk of emissions. Correspondingly, the small number of airports to supply would facilitate implementation. Singapore only has one main airport (Changi), about 75% of the traffic in Thailand is from Bangkok,[126] Jakarta, Surabaya and Bali handled over half of the total annual traffic in Indonesia in 2024, and in Malaysia there are 7 international airports and Kuala Lumpur handles more than 55% of the national traffic.

Figure 7.13 Energy demand per capita for aviation in relation to GDP per capita, 2022



Notes: ASEAN = Association of Southeast Asian Nations; GDP = Gross Domestic Product. Singapore, United Arab Emirates and countries with a population smaller than 3 million people that had a high energy demand per capita are not represented in the figure to avoid distorting the axes. Singapore had an energy demand for aviation of 39 MJ per capita per year.

Source: IEA analysis based on International Monetary Fund for GDP.

Nearly 85% of the Southeast Asia population is well below the global average energy consumption per capita for aviation.

[124] This disregards future demand growth, which is expected by the time these facilities come online. Other assumptions are an electrolyser efficiency of 67% (on lower heating value basis) and 5 000 operating hours per year.

[125] Singapore published a Sustainable Air Hub Blueprint in 2024, Thailand made a proposal in 2024 to update the Alternative Energy Development Plan, Malaysia has a National Energy Transition Roadmap published in 2023 and Indonesia is developing a SAF action plan.

[126] Bangkok has two airports which are about 30 km apart and could presumably aggregate demand for SAF.

Another opportunity lies in the state-owned companies involved in the aviation sector, which could serve to kick off the market by procuring synthetic fuel. For example, in Indonesia, 37 airports are managed by Angkasa Pura, which is an state-owned enterprise established in 2024.[127] However, the government only regulates airlines and not fuel suppliers, which would make implementation of such a mandate more difficult. Pertamina, the state-owned oil company, has engaged in partnerships to develop sustainable aviation fuels (SAF).

Table 7.1 Aviation-related indicators for the top four Southeast Asian markets

	Singapore	Thailand	Indonesia	Malaysia
Aviation demand (PJ/yr)	300 (2023)	200 (2024)	120 (2023)	130 (2020)
Traffic (million passengers)	62.5 (2024)	120 (2024)	80 (2024)	135 (2024)
Domestic share (%)	0%	40%	80%[128]	55%
SAF blending mandates	1% (2026), 3-5% (2030)	1% (2026), 8% (2036)	5% (2025)	47% (2050)

Notes: SAF mandates are only in place for Singapore.

Power generation

Several use cases for low-emissions hydrogen could be relevant for Southeast Asia

Hydrogen can be used to produce electricity by using fuel cells (though electrochemical conversion), in gas turbines (through steam production from hydrogen combustion) and in coal-fired power plants (combustion as ammonia). There are at least four different use cases for hydrogen in the power sector that are relevant in Southeast Asia. Depending on the system configuration, there might be alternatives to hydrogen that are more suitable or more cost effective.

Hydrogen can be used where domestic renewable potential is limited and imports are necessary to satisfy electricity demand, such as in Brunei and Singapore, which have limited land availability.

In island power systems, which have limited flexibility, generation from hydrogen can provide some resilience (using fuel cells since the level of demand is relatively small and therefore does not justify the use of turbines). In these cases, hydrogen storage can complement batteries by meeting demand during prolonged periods

[127] Airports have been managed by state-owned enterprises since to the 1960s.
[128] Extrapolated to the entire year based on values from January to August.

without renewable generation. There could be an opportunity for hydrogen use given that alternative fuel in remote islands is typically diesel, and island systems have high electricity prices. Examples include Indonesia,[129] the Philippines, Thailand and Viet Nam, which are the countries with the most islands in Southeast Asia. Several "Renewstable" projects combining solar, wind, batteries, hydrogen storage and fuel cells are now being developed in Southeast Asia with the aim of providing a stable electricity supply. Of those that have long-term agreements, 23 are in Indonesia, 5 in Viet Nam and 15 in the Philippines, with an average investment of EUR 100 million per project.

Hydrogen could be converted to power in systems with a high share of renewables (especially wind) and can ensure that load is met during periods of low renewable generation. This can be done at large scale through gas turbines or co-firing in coal plants (see below). This use complements the flexibility provided[130] by varying the electrolyser load. Viet Nam is considering hydrogen generation in its long-term plans.

Hydrogen could also be part of a mix of industrial gases that are used for power generation, and where part of the generation is exported to the electricity grid. This can be attractive when the wholesale electricity prices are high, and private companies are now evaluating this use case for Indonesia, Viet Nam and Thailand.

Ammonia co-firing is being tested by multiple countries including in Southeast Asia

Ammonia co-firing with coal is a possibility for the entire region. In 2024, coal capacity was nearly 30% (112 GW) of the total installed capacity in the region and nearly half of total generation. The coal fleet in Southeast Asia is relatively young, with almost 60% less than 10 years old and another 12.5 GW under construction. Ammonia co-firing is not yet commercially available; it has a technology readiness level of 7, with multiple countries testing up to 35% co-firing (Table 7.2). A potential issue with ammonia combustion is the production of higher nitrogen oxides (NO_x), an air pollutant, but results from demonstration have indicated that NO_x levels when co-firing were no higher than for standard coal combustion.

[129] Indonesia has nearly 1 700 diesel generation units spread across 416 locations with a total generation capacity of 588 MW.
[130] Electrolyser load variation and hydrogen reconversion to power are two ways hydrogen can provide flexibility to the power sector, but there are other options, like batteries, hydropower, long-duration energy storage, demand response, thermal generation and grid expansion.

Table 7.2 Targets, pilot and demonstration projects for ammonia co-firing in coal plants

Country	Year	Stage	Blending ratio	Notes
Indonesia	2022	Pilot	Undisclosed	100-MW unit
China	2022	Pilot	25%	40-MW_{th} unit
India	2023	Announcement	Up to 20%	330-MW unit
Indonesia	2023	Pilot	Possibility of up to 60%	Actual ratio tested undisclosed
China	2023	Pilot	Up to 35%	300 MW
Japan	2024	Pre-commercial	20%	1-GW plant
Indonesia	2025	Pilot	3%	300-MW unit
Japan	2027	Commercial	20%	Target
Korea	2027	Demo	20%	Target
Japan	2028	Pilot	50%	Target
Korea	2030	Commercial	20%	Target

Notes: Projects at the memorandum of understanding stage or undergoing feasibility studies are excluded.

The cost of retrofitting a coal unit to co-fire ammonia is relatively low, in the order of USD 20-55/kW, in comparison to a typical investment of USD 1 600/kW for a supercritical coal plant in Asia. The investment needs for retrofitting are therefore manageable; the main cost penalty related to co-firing is the fuel. The fuel cost for coal plants is about USD 30/MWh, while renewable ammonia – even in 2035, by when costs are expected to come down – is expected to cost about 14 times more. Blending at 20% would therefore increase the fuel cost contribution by almost 3 times. When considering typical emissions for coal plants, the abatement cost for co-firing ammonia would be in the order of USD 800/t CO_2 (independent of the blending ratio).

In terms of wider regional collaboration, ammonia co-firing has been recognised by energy ministers as an alternative for phasing down coal. Co-firing is also being explored as part of the AZEC, mostly in the form of MoUs and pilot projects. Japan and Thailand are studying the possibility of co-firing 20% ammonia at a 1.4-GW coal plant in Indonesia. Cross-border collaboration is also underway in the private sector: For example, IHI Corporation (a Japanese company) worked together with PT Pupuk (an Indonesian state-owned enterprise) to test co-firing in 2022, and is aiming to further study commercialisation potential. The Japanese utility JERA (Japan's Energy for a New Era) and Aboitiz Power Corporation (a Filipino company) will also evaluate co-firing in coal plants in Philippines.

Looking ahead, the potential ammonia demand from coal co-firing depends on the pathway followed. Coal generation could increase by more than 30% by 2040 if historical trends continue, but it could decrease by more than 45% if announced policy goals are achieved. Assuming a 60% co-firing ratio, the coal-fired electricity generation in the latter scenario would result in an ammonia demand of 115 Mtpa in 2040. This is more than ten times the current regional ammonia production and could reduce CO_2 emissions by over 200 Mtpa. This level of 60% ammonia co-firing would bring the specific emissions of coal plants on par with those from gas power plants. The high fuel costs mean that it may be more economical to use coal plants with co-firing to provide flexibility to the power system, although this may require targeted equipment upgrades and capacity remuneration mechanisms.

Government plans currently point to a decrease in coal capacity. Coal transition mechanisms, such as blended finance loans and managed transition vehicles, can help facilitate the early termination of coal power purchase agreements (which are the main barrier to phase-out), with little to no increased cost for consumers. This suggests that the coal fleet for which ammonia could potentially be used could decrease over time, with the pace defined by the speed at which coal transition policies are introduced. From an energy security perspective, seven of the ten ASEAN countries are net coal importers, so any delay in coal phase-out (including by using ammonia) would lead to prolonged reliance on energy imports.

Government plans relevant to power generation

Singapore has limited domestic renewable potential, so it is expected to continue to rely on imports to meet its power demand. Imports may be directly as electricity, as natural gas coupled with carbon capture, as hydrogen, or as ammonia. Singapore is already connected to Malaysia (525 MW), with plans to expand that connection to 1 050 MW. Other plans include 3.4 GW from other parts of Malaysia, 1.2 GW from Viet Nam, and up to 1 GW from Cambodia. These will all contribute to the country's 4 GW of "low-carbon" electricity import target for 2035. For context, Singapore has a total installed capacity of about 13 GW. The direct use of ammonia is also being explored through the Pathfinder project, which aims to deploy a 55-65 MW ammonia power plant by 2028. The selection of project developers for this initiative should be finalised this year (see Strategies). Natural gas coupled with carbon capture is currently at the pre-feasibility stage. This portfolio of technologies would allow Singapore to fully decarbonise its electricity system, but the role of each technology will depend on the findings from initial stages, as well as technology evolution.

Viet Nam's 8th Power Development Plan, published in May 2023 and amended in April 2025, details a pathway for power sector development to 2030 and a vision to 2050. This sees no role for hydrogen in 2030, but in 2050, it includes 25.8 GW of thermal generation using biomass and ammonia, 7 GW of gas-fired thermal power running entirely on hydrogen, 18.2-26.1 GW of liquefied natural gas (LNG) thermal generation with hydrogen combustion and 8.6-11.3 GW of converted LNG thermal generation running entirely on hydrogen. As a point of reference, the total installed capacity by 2050 is expected to be 775-839 GW, of which 491-526 GW are from solar and wind.

Indonesia also sees a prominent role for hydrogen derivatives in its hydrogen and ammonia roadmap. Based on different scenarios in the roadmap, ammonia co-firing could reach 3% in 2025, 10% in 2030 and 30% in 2034, with hydrogen co-firing starting later and reaching 10% in 2035 then ramping up to 60% by 2045. By 2060, pure ammonia power plants are expected to reach up to 8.4 GW and hydrogen power plants up to 25.3 GW consuming 4.2 Mtpa of hydrogen. Fuel cells could also play a role in power generation. These capacities are in line with the latest 2024-2060 Electricity Plan. Indonesia is already testing renewable ammonia co-firing at 3% at Labuan, and is exploring several ammonia and hydrogen co-firing pilots for 2025-2026 in gas turbines of 16-300 MW.

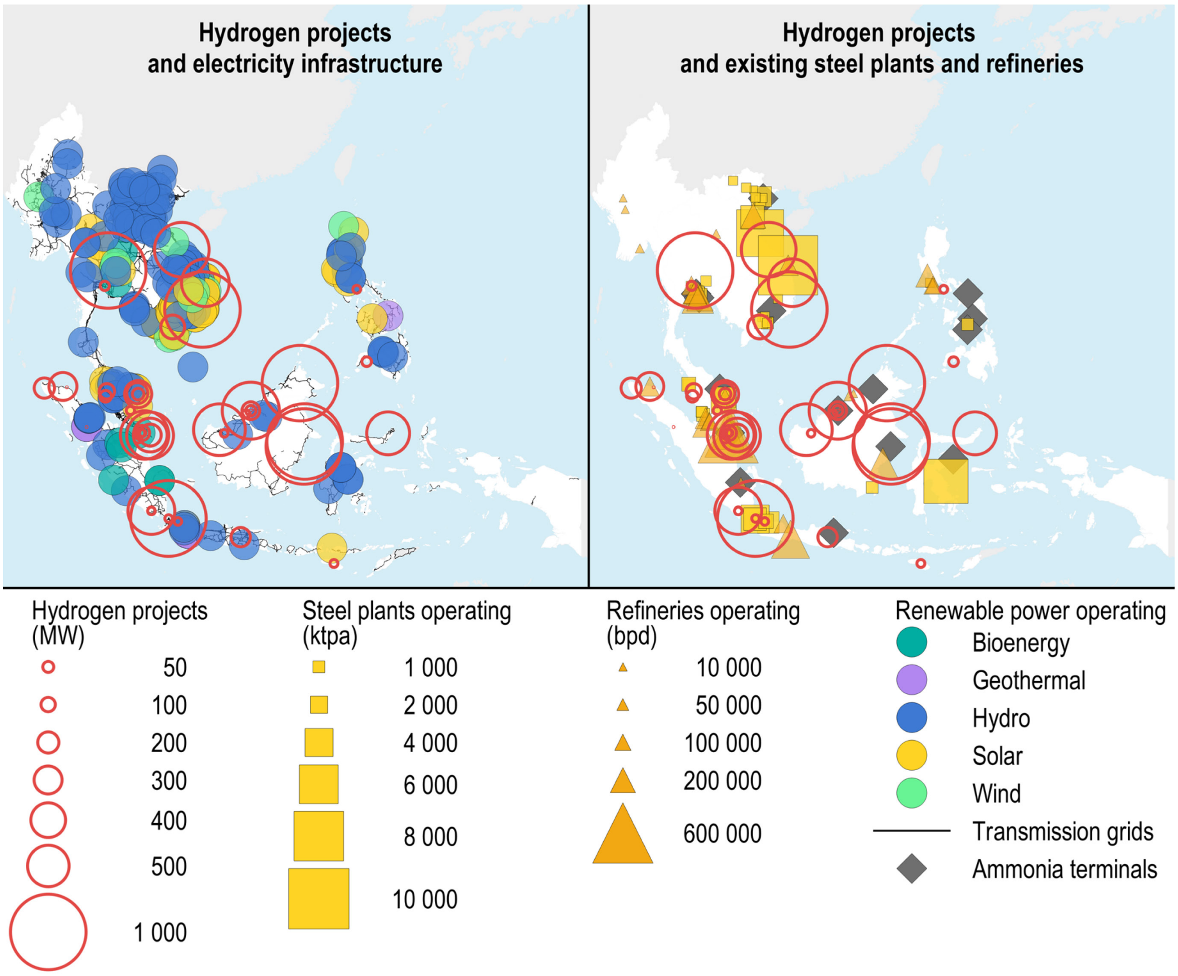
Industrial hubs

Industrial hubs can be a way to aggregate demand from multiple users, creating economies of scale to achieve low costs for production or for shared import infrastructure. In such a hub, each user commits to a small share of offtake, thereby spreading the risks associated with supply and infrastructure development. Existing industrial hubs are commonly located close to ports since trade of raw materials, products and equipment is essential for operations. The factors[131] affecting the siting of hubs include existing infrastructure (electricity grid, gas grid, ports, rail and roads), industrial assets and potential hydrogen demand, as well as local characteristics such as workforce availability, service companies and social acceptance. Hubs can be classified into three categories: industrial demand hubs, bunkering and fuel distribution hubs, and supply hubs.

In Southeast Asia, the main industrial demand hubs are in Rayong (Thailand), Vung Tau (Viet Nam), Jakarta (Indonesia) and Kuala Lumpur (Malaysia) (Figure 7.14). Rayong hosts all of Thailand's existing steel capacity, one large ammonia plant operated by PTT (a state-owned enterprise) and two refineries with a total capacity of 425 kbpd. Vung Tau has several steel plants (with eight furnaces and a capacity equivalent to about a quarter of Viet Nam's steel production capacity), the largest ammonia plant in the country (Phu my, with a capacity of 540 ktpa) and is within 50 km of the Saigon port, the largest port in Viet Nam. In Malaysia, Kuala Lumpur has several steel plants, including an existing 1.5 Mtpa DRI plant in Selangor. The Port Klang (within 30 km of Kuala Lumpur) is the largest in the country. Two of the four ammonia plants in the country are within 325 km. Jakarta has three steel plants with a capacity equivalent to a fifth of Indonesia's capacity, and the Port of Tanjung Priok is the largest in the country. Even though Jakarta does not have any large chemical plants, the large chemical companies headquartered there may facilitate collaboration on new projects. Jakarta's large shipping fuel demand can also provide an opportunity for ammonia bunkering. Elsewhere, Singapore is a natural hub for bunkering hydrogen derivatives, given its large fuel consumption and ongoing efforts on shipping fuels (see Shipping).

[131] See Chapter 8 of GHR-24 for more details.

Figure 7.14 Potential hydrogen hubs in Southeast Asia



Note: Only includes projects with an announced operating date before 2030, assuming they start on time.
Sources: IEA analysis based on IEA Hydrogen Projects database (September 2025), Global Energy Monitor, Argus Media Group, All rights reserved, Open Infrastructure Map, Fractracker.

Existing industrial hubs provide an initial opportunity to trigger demand for low-emissions hydrogen, as does Singapore, as the world's largest bunkering hub.

Near-term actions

Support deployment of renewables, which can create positive spillover effects for hydrogen development. Solar PV and onshore wind – the technologies that would be used for renewable hydrogen – are still nascent in Southeast Asia. In 2024, 8 of the 10 ASEAN countries had a share of less than 5% of electricity generation from these two technologies. Accelerating deployment of renewables will benefit hydrogen by developing the market, industry and workforce; building confidence among financial institutions and experience with risk mitigation instruments that will decrease the cost of capital; and standardising administrative processes for permitting, environmental assessment and similar steps. All of these steps could benefit hydrogen projects. Rather than deploying mega projects with multiple components and risks, developing renewable projects first, and then adding steps relating to electrolysis, would enable a gradual approach with fewer risks. A mature renewable sector can also attract large companies and promote competition, which might lead them to explore new avenues for growth such as hydrogen production. Cost data from actual renewable projects would also reduce the uncertainty around the main cost driver (the electricity input) for renewable hydrogen projects. Finally, reducing the cost of electricity is key for hydrogen projects to take off; policies targeted at renewables will have a positive impact on hydrogen projects.

Deploy pilot hydrogen projects and progressively build experience with the technology. Currently, 94% of the project pipeline to 2030 in Southeast Asia (and an even larger fraction if the full pipeline is considered) is undergoing feasibility assessment or at the early stages. A more diversified project portfolio is needed to test different configurations, applications, regions and electricity sources, among other aspects. This would build understanding of what works best in the local context and could also be coupled with regulatory sandboxes to test different policies, providing a stepping stone for larger projects. Piloting would need to begin today so that lessons could be incorporated in the design of the larger plants in a timely manner. Pilot projects would also develop essential experience in the private sector (such as among project developers and engineering firms). Pilots are also needed in end uses, especially for new applications like aviation or shipping, which allow for a progressive ramp-up.

Leverage existing hydrogen applications to anchor demand and create economies of scale. Southeast Asia already has a large existing hydrogen demand (4 Mtpa), which is heavily concentrated: Over half of the entire regional demand is in methanol production in Malaysia (1 site), refining in Singapore (3 plants), and ammonia in Indonesia (5 plants). To leverage these applications, policies would need to move from promoting incremental changes, such as energy efficiency, to promoting a step change such as a fuel or technology shift. Focusing on those applications and hydrogen clusters with the largest scale would not only enable mitigation of the bulk of emissions from hydrogen production, but also create economies of scale that other applications can then leverage. Renewable ammonia production could use existing assets (synthesis units, transport and storage), enabling exports to regions like Korea, Japan or the European Union, and achieve low transport costs.

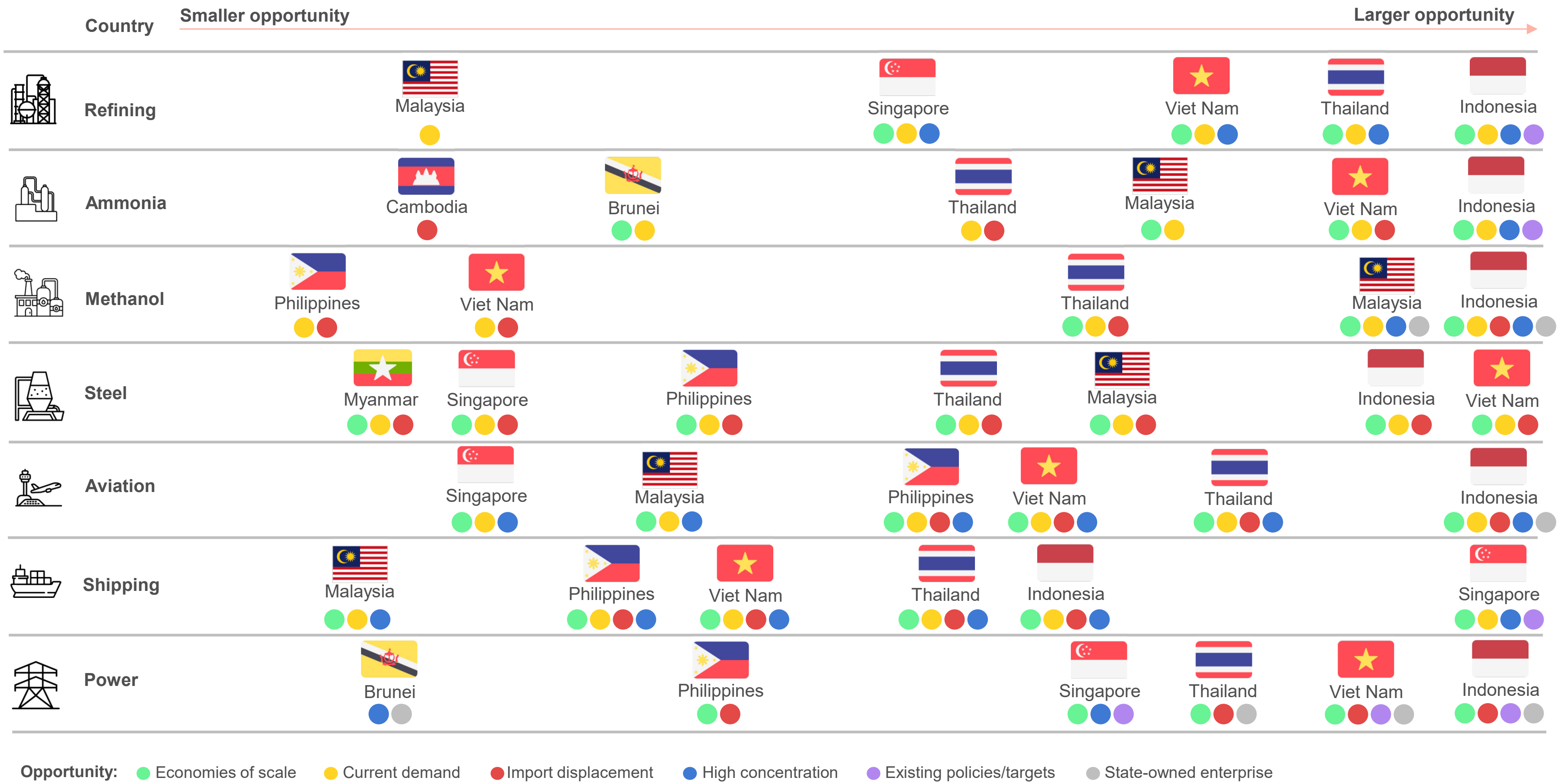
Create demand for the uptake of low-emissions hydrogen. Currently, there are limited incentives to decarbonise existing hydrogen uses or promote new applications. Some alternatives that have been used in other emerging economies include demand aggregation through hubs (Brazil), auctions with a fixed premium for renewable ammonia production (India), financial support in the form of loans and loan guarantees (Chile), and tax incentives (Argentina). Other options such as quotas, grants and targets are also available. Ease of application and accelerated permitting can be important enabling measures, especially for sectors with nascent consumer-led demand and a willingness to pay for decarbonised products like textiles (as in Viet Nam). Regardless of the instrument used, it is important to provide visibility on how such instruments might evolve over time and what criteria will be used for their review. At the same time, binding policies can give a clear signal on demand creation. For example, a legislated quota will provide greater certainty than an aspirational target. Both of these aspects will help de-risk projects and improve their long-term viability by increasing the chances of hydrogen offtake, which is one of the main barriers to taking FID, and potentially increasing the willingness to pay from specific consumers.

Develop certification schemes for hydrogen and its derivatives. None of the Southeast Asian countries has a certification scheme in place, but such schemes will be key to enabling implementation of relevant policies, ensuring emissions reduction, creating transparency for consumers and allowing for tracking of environmental attributes, as well as being essential to enabling global trade. A full certification scheme can take years to develop, which is why efforts would need to start as soon as possible. For example, the European Union's hydrogen strategy was published in July 2020 and the full methodology for GHG measurement entered into force in June 2023. In Australia, the first strategy was published in late 2019, and work to define the guarantees of origin scheme is still being undertaken in 2025. Southeast Asian countries could use the ISO standard as a starting point, with the aim of achieving interoperability with other schemes around the world. Mutual recognition of the schemes that already have rules in place is crucial. Step-by-step development could also be considered, starting with GHG emissions and then broadening the scope to include other aspects such as land use, water consumption or social dimensions. Similarly, the system boundaries could first consider hydrogen production and then expand to production of derivatives, and to transport. A clear timeline and criteria for these changes over time would benefit hydrogen deployment.

Use policy and financial instruments to address the high cost of capital. Hydrogen projects are capital intensive, which makes the cost of capital critical to the overall production cost. Southeast Asia has a higher WACC than most advanced economies, as a result of country risk profiles and low maturity of the renewables sector. In the case of renewables, providing predictability of the revenue streams using feed-in tariffs, contracts for difference, power purchase agreements, other types of long-term contracts or pricing instruments should help to bring down the cost of capital. From the financing perspective, some alternatives include low-cost debt, payment guarantees (or other credit enhancement arrangements to cover payment risk), concessional and grant funding. For hydrogen projects, having large companies as credible off-takers (for example, from Japan), and companies that have built projects in other regions, would help to decrease the cost of capital.

Collaborate internationally and learn from best practices in other regions. Collaboration across governments, multilateral organisations, and industry both within and outside the region can be useful. Potential learning may be in terms of policy measures that have been used and their specific design, including scope, level of incentive and eligibility. As shown in Chapter 6 Policies tax incentives are commonly used across emerging economies. There is also an opportunity to co-finance the projects with the private sector and maximise capital mobilisation. Learning may also relate to aspects such as safety regulations, regulation of the hydrogen infrastructure and certification schemes. Further opportunities to learn from deployment could arise from attracting foreign companies that have built projects elsewhere. This can help to develop the local workforce and result in lower project costs. Collaboration can also take place at the research level, to maximise synergies and avoid duplication. This goes together with regional collaboration, for example through AZEC or the ASEAN Hydrogen Task Force.

Figure 7.15 Opportunities by sector for deployment of low-emissions hydrogen in Southeast Asia



Note: Current demand is omitted for power generation.

The countries with the largest energy and hydrogen demand today provide the largest opportunities for hydrogen deployment.

Annex

Explanatory notes

Projections and estimates

Projections and estimates in the Global Hydrogen Review 2025 are based on research and modelling results derived from the most recent data and information available from governments, institutions, companies and other sources as of July 2025.

Terminology relating to low-emissions hydrogen

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

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

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

Terminology for carbon capture, utilisation and storage

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

Project status

For the analysis of the pipeline of announced projects, four potential statuses have been considered:

- Operational: includes projects that are already producing hydrogen, even if they are in a ramp-up period and have not achieved their full production capacity.
- Final investment decision: includes projects that have taken a firm investment decision, including those that have started construction.
- Feasibility studies: includes projects that are undertaking pre-feasibility studies, feasibility studies or front-end engineering design.
- Early stage: includes projects at very early stages of development, e.g. only a co-operation agreement among stakeholders has been announced or a general announcement of the intention to develop a project has been made.

Currency conversions

This report provides the stated values of programmes and projects in the currency stated in their announcement. In many instances these values are converted to US dollars for ease of comparison. The currency exchange rates used correspond to an average value for the year of the announcement based on World Bank exchange rates. For 2025 values, average exchange rates are based on the International Monetary Fund.

Reporting hydrogen demand

In this report, demand includes hydrogen that has been intentionally produced for utilisation, including pure hydrogen (used in applications such as ammonia production and refining), and hydrogen which is mixed with carbon-containing gases (used in applications such as methanol production and steel manufacturing). It excludes hydrogen which is present in residual gases from industrial processes (e.g. coke ovens and steam crackers), which are used for heat and electricity generation. This hydrogen is not deliberately produced for a specific application, rather its use is linked to the inherent presence of hydrogen in these residual streams. In addition, in this report we do not include estimations of historical use of small amounts of hydrogen in applications like glassmaking, electronics and metal processing.

Traditional and new applications for hydrogen

Beyond the existing applications for hydrogen in refining, the chemical industry, steel production, and other specialised applications, hydrogen can also be used in a wide range of new applications. Hydrogen has not yet been used at scale in these applications, but efforts to reduce emissions and enhance energy security are expected to drive up hydrogen use in some of these new applications, particularly in sectors where emissions are hard to abate, and other low-emissions technologies are either unavailable or very difficult to implement.

Tracking total hydrogen use alone is not sufficient to assess progress on hydrogen adoption, and particularly whether it is happening in the direction and at the pace required for hydrogen to play its role in the clean energy transition. The use of hydrogen by application also needs to be tracked in order to assess uptake in new applications. For reporting purposes in the IEA's Global Hydrogen Review, we use two categories of applications for hydrogen:

- Traditional applications, including refining; feedstock to produce ammonia, methanol and other chemicals; and as a reducing agent to produce direct reduced iron (DRI) using fossil-based synthesis gas. This category also includes the use of hydrogen in electronics, glassmaking or metal processing, although these are not included in our reporting.
- Potential new applications, such as the use of hydrogen as a reducing agent in 100%-hydrogen DRI, long-distance transport, production of hydrogen-based fuels (such as ammonia or synthetic hydrocarbons), biofuels upgrading (e.g. hydrogenation of fats and oils), high-temperature heating in industry, and electricity storage and generation, as well as other applications in which hydrogen use is expected to be very small due to the existence of more efficient low-emissions alternatives.

Enabling indicators to assess regional factors affecting project development

This part of the annex provides a detailed overview of the methodology used to evaluate regional enabling conditions as part of the assessment of the likelihood of low-emissions hydrogen production projects becoming operational by 2030. The regional component is one of three key deliverability factors, alongside project size and target end-use, described in Box 3.1.

The regional assessment is based on 66 indicators (Table A.1) grouped into seven enabling factors and distributed across three categories that can influence the development and delivery of hydrogen projects:

- business environment
- energy infrastructure
- status of the hydrogen market.

Indicators were selected to capture a wide range of elements relevant to project implementation. Some indicators are cross-cutting (e.g. corruption perception index, regulatory quality), while others are technology-specific (e.g. renewable energy potential for electrolysis, availability of CO_2 storage for CCUS). The data for these indicators was collected from publicly available sources, including the World Bank, IEA, IRENA, and other relevant institutions.

Comprehensive data was not always available for recent years; in order to make the assessment as comprehensive as possible, data was collected for 2018 to 2024, with priority given to more recent datasets. The indicators were compiled for all countries currently hosting hydrogen production projects listed in the IEA Hydrogen Production Projects Database.

Each indicator was normalised across countries to get a value in the range of [0-1], where higher values represent more favourable conditions for project development. The normalised values of the indicators grouped under each enabling factor were added up to give an overall score for each enabling factor. Then, each enabling factor was given a weight grade according to its importance, between 1 (least important) and 4 (most important), based on expert judgement. In some cases, the importance weights varied depending on whether the project involved electrolysis or CCUS technologies (Table A.2). Finally, the overall score for each enabling factor was multiplied by its corresponding importance rating to get a regional condition score for each country. Based on this score, countries were grouped into four categories, with those in the highest-scoring group considered to have the strongest enabling conditions for project delivery by 2030. The regional condition scores, when combined with size and end-use assessments, contributed to the classification of each hydrogen project into one of five categories assessing their likelihood of being operational by 2030: almost certain, strong potential, moderate potential, low potential and uncertain.

This assessment is not intended as a definitive forecast, but rather as a structured, comparative snapshot of project feasibility under current conditions. As data availability improves and project contexts evolve, results may be updated to reflect these changes.

Table A.1 Indicators for assessing regional enabling conditions

Category	Enabling Factor	Indicator	Description	Source
Business environment	Ease of doing business	Ease of doing business	The simple average of the scores for each of the ease of doing business topics: starting a business, dealing with construction permits, getting electricity, registering property, getting credit, protecting minority investors, paying taxes, trading across borders, enforcing contracts and resolving insolvency.	World Bank, 2021
		Political stability	Measures perception of the likelihood of political instability and/or politically motivated violence, including terrorism.	World Bank, 2023b
		Corruption Perception indicator	Measures perception of the extent to which public power is exercised for private gain, including both petty and grand forms of corruption, as well as "capture" of the state by elites and private interests.	World Bank, 2024b
	Industrial competitiveness	Competitive Industrial Performance Index	Benchmark of the ability of countries to produce and export manufactured goods competitively.	UNIDO, 2024
		Economic Complexity Index	Ranking of countries based on the diversity and complexity of their export basket.	Center for International Development at Harvard University, 2023
		Total trade volume	Total trade flow considering imports and exports [t].	CEPII, 2024
		Labour cost	Average hourly wage across all sectors.	ILO, 2024
	Financing cost	Weighted average cost of capital	Weighted Average Cost of Capital for more mature technologies [%].	IEA, 2024a

Category	Enabling Factor	Indicator	Description	Source
Energy and infrastructure	Energy infrastructure	Electricity access	Share of population with access to electricity.	IEA analysis
		Electricity demand per capita	-	IEA, 2024h
		Natural gas demand per capita	-	IEA, 2024h
	Access to low-emissions energy	Renewable energy potential	Sum of solar and wind energy potential.	IEA analysis based on: Copernicus Climate Change Service, 2025 European Space Agency, 2010 Protected Planet, n.d. World Wildlife Fund, n.d. FAO, n.d. Renewables.ninja, n.d.
		Regulatory Indicator for Sustainable Energy	Assesses countries' policy and regulatory support for renewable energy.	World Bank, 2024a
		Natural gas reserve	Natural gas proved reserves share.	Energy Institute Statistical Review of World Energy, 2024
		Availability of CCS infrastructure	Existing CCS infrastructure.	Oil and Gas Climate Initiative, 2025

Category	Enabling Factor	Indicator	Description	Source
Status of the hydrogen market	Hydrogen demand	Hydrogen demand	Calculation of H_2 requirement based on industry applications (Ammonia, Methanol, Refinery and Steel).	Argus Media Group, 2025 International Fertilizer Association, 2025 World Steel Association, 2025
	Hydrogen policies	Demand policies	Includes grant, load and loan guarantees, tax incentives, carbon levies, sectoral quota/mandates/bans, administrative, fuel standard, public procurement, and hubs policies.	IEA's Policies and Measures Database, 2025
		Supply policies	Includes grant, load and loan guarantees, fixed premium, tax incentives, and administrative policies.	
		Standards and trade policies	Includes guarantees of origin, definition/thresholds, regulation and design rules policies.	
		Infrastructure policies	Includes grant, planning, market governance, market access, safety, and blending policies.	
		Supply chain policies	Includes grant and tax incentives policies.	
		Target policies	Includes supply, cost, infrastructure, import/export, and industry policy targets.	
		CCUS policies	Includes enabling legislation and rules, grant, tax credit, loan, regulation of industry activities, strategic signalling and revenue support.	IEA, 2023

Table A.2 Relative Importance of Enabling Factors in Assessing Regional Conditions

Category	Enabling factor	Electrolysis projects	CCUS projects
Business environment	Ease of doing business	◑	◑
	Industrial competitiveness	◔	◔
	Financing cost	◕	◑
Energy infrastructure	Electricity access and generation	◑	-
	Natural gas infrastructure and demand	-	◕
	Access to low-emissions energy	◑	-
Status of hydrogen market	Hydrogen demand	◕	◕
	Hydrogen polices	●	●

Notes: The shading of icons indicates the level of importance from relatively low (○) to high (●), which are translated into weights for the enabling factor analysis. Relative importance levels have been evaluated based on expert judgement for each specific production route, and should not be compared between routes.

Sources of information

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Abbreviations and acronyms

ACER	Agency for Cooperation of Energy Regulators
AI	artificial intelligence
AEM	anion exchange membrane
ALK	alkaline
ASEAN	Association of Southeast Asian Nations
ASME	American Society of Mechanical Engineers
ATR	autothermal reforming
AUD	Australian dollars
AZEC	Asia Zero Emission Community
BAT	best available technology
BET	battery electric truck
BF	blast furnace
BOF	basic oxygen furnace

BoP	balance of plant
CAD	Canadian dollar
CAPEX	capital expenditure
CBAM	Carbon Border Adjustment Mechanism
CC	carbon capture
CCfD	carbon contract for difference
CCS	carbon capture and storage
CCU	carbon capture and use
CCUS	carbon capture, utilisation and storage
CEF	Connecting Europe Facility
CEM	Clean Energy Ministerial
CfD	contract for difference
CH_4	methane
CHPS	Clean Hydrogen Production Standard
CIF	Climate Investment Fund
CO_2	carbon dioxide
COMTRADE	United Nations Commodity Trade Statistics Database
COP	Conference of the Parties
DEVEX	development expenditures
DFI	development finance institutions
DME	dimethyl ether
DKK	Danish kroner
DoE	Department of Energy
DRI	direct reduced iron
EAF	electric arc furnace
EBITDA	earnings before interest, taxes, depreciation and amortisation
ECA	export credit agency
EIB	European Investment Bank
EMDE	emerging markets and developing economies
EOR	enhanced oil recovery
EPC	engineering, procurement and construction
EPEX	European Power Exchange
EPO	European Patent Office
ETS	Emissions Trading Systems
EUR	Euro
EV	electric vehicle
FC	fuel cell
FCET	fuel cell electric truck
FCEV	fuel cell electric vehicle
FEED	front-end engineering design
FID	final investment decision
FT	Fischer–Tropsch
G20	Group of Twenty
GBP	British pound
GCF	Green Climate Fund
GDP	Gross Domestic Product
GHG	greenhouse gases

GHR	gas-heated reformer
GHR	Global Hydrogen Review
GoO	guarantee of origin
H_2	hydrogen
H2-DRI	hydrogen-based direct reduced iron
H2I	The Hydrogen Initiative
HAR	Hydrogen Allocation Rounds
HBI	hot briquetted iron
HD	heavy-duty
HRS	hydrogen refuelling station
HS	Harmonized System
HT	high throughput
ICE	internal combustion engine
ICCT	International Council on Clean Transportation
IDB	Inter-American Development Bank
IDC	Industrial Development Corporation
IEC	International Electrochemical Commission
IFC	International Finance Corporation
IHTF	International Hydrogen Trade Forum
IMO	International Maritime Organization
INR	Indian rupees
IPCC	Intergovernmental Panel on Climate Change
IPCEI	Important Projects of Common European Interest
IPF	International Patent Family
IPHE	International Partnership for Hydrogen and Fuel Cells in the Economy
IPO	initial public offering
IRA	Inflation Reduction Act
IRENA	International Renewable Energy Agency
ISCC	International Sustainability and Carbon Certification
ISO	International Organization for Standardization
JOGMEG	Japan Organization for Metals and Energy Security
JV	joint venture
LTDA	Long-Term Decarbonization Auction
LCOE	levelised cost of electricity
LCOH	levelised cost of hydrogen
LCV	light commercial vehicle
LD	light-duty
LH_2	liquid hydrogen
LNG	liquefied natural gas
LOHC	liquid organic hydrogen carrier
LPG	liquefied petroleum gas
MD	medium-duty
MeOH	methanol
METI	Ministry of Economy, Trade and Industry
MHI	Mitsubishi Heavy Industries
MOTIE	Ministry of Trade, Industry and Energy
MoU	Memorandum of Understanding

NASDAQ	National Association of Securities Dealers Automated Quotations
NEA	National Energy Administration
NG	natural gas
NH_3	ammonia
NOK	Norwegian kroner
NOx	nitrogen oxides
NREL	National Renewable Energy Laboratory
OEM	original equipment manufacturer
OH	hydroxyl radical
OHF	open hearth furnace
OPEX	operating expenditure
PCI	Projects of Common Interest
PEM	proton exchange membrane
PGO	product guarantee of origin
PNRE	Pertamina New and Renewable Energy
PV	photovoltaic
RD&D	research, development and demonstration
RED	Renewable Energy Directive
RES	renewable energy source
RFNBO	renewable fuels of non-biological origin
RfP	Request for proposals
SAF	sustainable aviation fuel
SEDC	Sarawak Economic Development Corporation
SIDF	Saudi Industrial Development Fund
SIGHT	Strategic Interventions for Green Hydrogen Transition
SMR	steam methane reforming
SOEC	solid oxide electrolyser
SOFC	solid oxide fuel cell
SPV	special purpose vehicle
STEPS	IEA Stated Policies Scenario
TCO	total cost of ownership
TPA	Third-party access
TPI	Technology Performance Insurance
TRL	technology readiness level
UNFCCC	United Nations Framework Convention on Climate Change
UNIDO	United Nations Industrial Development Organization
USD	United States dollars
VAT	value added tax
VC	venture capital
VRE	variable renewable electricity
WACC	Weighted average cost of capital
WtW	well-to-wake
ZNZ	zero or near-zero

Units

A	ampere
°C	degree Celsius
bar	metric unit of pressure
bcm	billion cubic metres
DWT	deadweight tonnage
EJ	exajoule
g	gramme
GJ	gigajoule
GVW	gross vehicle weight
GW	gigawatt
GWh	gigawatt-hour
GWh/yr	gigawatt-hours per year
GWP	global warming potential
GW/yr	gigawatts per year
HHV	higher heating value
inch	inch
kg	kilogramme
kg CO_2-eq	kilogramme of carbon dioxide equivalent
km	kilometres
kt	kilotonnes
ktpa	kilotonnes per annum
kW	kilowatt
mbpd	thousand barrels per day
MBtu	million British thermal units
MJ	megajoule
Mt	million tonnes
Mtpa	million tonnes per annum
Mt CO_2	million tonnes of carbon dioxide
Mt H_2-eq	million tonnes of hydrogen equivalent
MW	megawatt
MW_{th}	thermal megawatt
MW/yr	megawatts per year
MWh	megawatt-hour
Nm^3	normal cubic metre
PJ	petajoule
ppb	parts per billion
t	tonne
t CO_2	tonne of carbon dioxide
t CO_2-eq	tonnes of carbon dioxide equivalent
TEU	twenty-foot equivalent unit
tpa	tonnes per annum
TWh	terawatt-hour
V	volt
yr	year

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