IRENA
International Renewable Energy Agency

# GLOBAL HYDROGEN TRADE TO MEET THE 1.5°C CLIMATE GOAL

## PART I

## TRADE OUTLOOK FOR 2050 AND WAY FORWARD

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For questions or to provide feedback: publications@irena.org

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# EXECUTIVE SUMMARY

Unlike fossil fuels, for which large reserves are concentrated in certain countries and regions, renewable energy resources (solar, wind, geothermal, etc.) are available at a viable scale in every country. The geographical concentration of fossil fuel reserves has made some countries into major producers, while most countries are predominantly importers. Renewable energy, in contrast, can be produced everywhere (although the cost-effectiveness varies by location) and therefore has the potential to dramatically change how and between whom energy is traded. However, until recently there has been no cost-effective way to transport renewable electricity over long distances to link low-cost production sites with demand centres. Suitable transmission lines are rare and costly to construct. The use of hydrogen as an energy carrier could be an answer, enabling renewable energy to be traded across borders in the form of molecules or commodities (such as ammonia).

The critical factor that will determine the cost-effectiveness of trade in hydrogen will be whether scale, technologies and other efficiencies can offset the cost of transporting the hydrogen from low-cost production areas to high-demand areas. To produce green hydrogen, renewable energy is converted to hydrogen through electrolysis, and this hydrogen is further processed to increase its energy density. The further processing may take the form of liquefaction, use of liquid organic hydrogen carriers, or conversion to ammonia, methanol, steel or synthetic fuels. The additional conversion steps translate into energy losses and therefore an increase in the cost per unit of energy delivered. These losses will be the same regardless of whether the conversion is done in an importing or an exporting region and thus will not be a differentiator when the final commodity is directly used without reconversion to hydrogen. Thus, to make trade cost-effective, the cost of producing green hydrogen must be sufficiently less expensive in the exporting region than in the importing region to compensate for the transport cost. This cost differential will become larger as the scale of projects increases and technology develops to reduce transport costs. Hydrogen trade can lead to a lower cost energy supply since cheaper (imported) energy is tapped into. It can also lead to a more robust energy system with more alternatives to cope with unexpected events.

There are many milestones to achieve before global hydrogen trade becomes a viable, cost-effective option at scale. This study uses techno-economic analysis to explore the conditions that would need to be in place to make such trade economically viable.

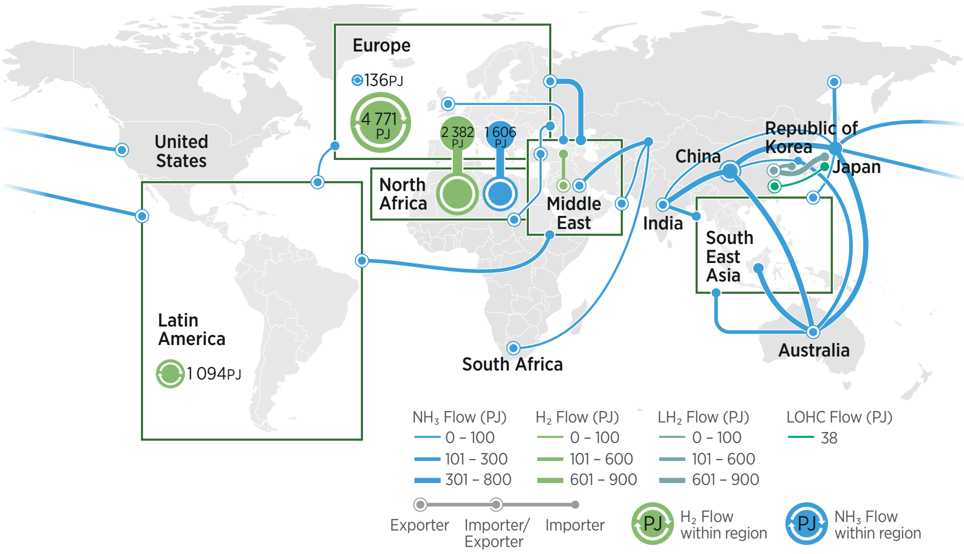
It explores a 1.5°C scenario in 2050, as laid out in IRENA's *World Energy Transitions Outlook* (IRENA, 2022a), in which 12% of the final energy demand is supplied by hydrogen. The techno-economic analysis of the various technological pathways available for hydrogen transport (Part II of this report series [IRENA, 2022b]) is combined with a spatial analysis (Part III of this report series [IRENA, 2022c]) that estimates the technical potential of hydrogen produced using renewables ("green hydrogen") and the cost this would entail for the entire world. The analysis is based entirely on cost optimisation and does not consider such factors as energy security, political stability or economic development, among others, that may also impact the trade outlook. Most of these additional factors are explored in a parallel IRENA report on hydrogen geopolitics (IRENA, 2022d). The analysis focuses on two commodities – green hydrogen and ammonia – and will be extended to other commodities in the future.

By 2050 in this 1.5°C scenario, about one quarter of the total global hydrogen demand[1] (equivalent to 18.4 exajoules [EJ] per year or about 150 megatonnes [Mt] of hydrogen per year) could be satisfied through international trade. The other three quarters would be domestically produced and consumed. This is a significant change from today's oil market, where the bulk (about 74%) is internationally traded, but it is similar to today's gas market, of which just 33% is traded across borders. Of the hydrogen that would be internationally traded by 2050 in the 1.5°C scenario, around 55% would travel by pipeline, and most of the hydrogen network would be based on existing natural gas pipelines that would be retrofitted to transport pure hydrogen, drastically reducing the transport costs (IRENA, 2022b). This pipeline-enabled trade would be concentrated in two regional markets: Europe (85%) and Latin America (see Figure 0.2). The remaining 45% of the internationally traded hydrogen would be shipped, predominantly as ammonia, which would mostly be used without being reconverted to hydrogen.

Figure 0.2 shows the hydrogen trade outlook for 2050 in a scenario where the production and transport costs are optimistically low. Hydrogen trade develops in regional markets to a large extent. Europe's main trading partners are North Africa and the Middle East, and Australia mainly supplies the Asian market. The intra-regional market for Latin America is significant, with some exports to Europe.

[1] *Global hydrogen demand is 74 EJ/yr. This study excludes the demand for the power sector (21 EJ/yr) and combined with other minor adjustments results in a hydrogen demand of 50 EJ/yr (including the hydrogen used for ammonia production) used as input to the model*

**FIGURE 0.1. Global hydrogen trade flows under *Optimistic* technology assumptions in 2050**




Note: Optimistic capital expenditure assumptions for 2050: Photovoltaic (PV): USD 225-455/kW; onshore wind: USD 700-1070/kW; offshore wind: USD 1275-1745/kW; electrolyser: USD 130/kW. Weighted average cost of capital: Per 2020 values without technology risks across regions. Green hydrogen technical potential is based on assessing land availability for solar PV and wind. Demand is in line with a 1.5°C scenario from the *World Energy Transitions Outlook 2022* (IRENA, 2022a). LOHC = liquid organic hydrogen carrier.

*Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city, or area or of its authorities, or concerning the delimitation of frontiers or boundaries.*

The conversion of hydrogen to ammonia is already commercially viable and applied at large scale; ammonia is widely traded today (about 10% of the global production) and has a developed transportation infrastructure (ports, vessels, storage). Ammonia can also be directly used as feedstock and fuels and does not necessarily need to be reconverted to hydrogen. However, the existing, growing market for ammonia needs to be decarbonised to reach the 1.5°C scenario. By 2050, global ammonia demand could reach 690 Mt/year [IRENA & AEA, 2022]). Almost 80% of this (561 Mt/year) would be used as chemical feedstock and as fuel for shipping and power, and only 20% would be used as a hydrogen carrier.

As the operating costs of renewables are very low, having a low weighted average cost of capital (WACC) is critical to the cost-effectiveness of trade. Absolute levels and country differences in WACC both significantly affect the trade outlook and determine whether a country becomes an exporter or an importer. If WACC remains roughly as it is today, countries that have good-quality resources and low WACC would become the largest green hydrogen exporters and would be collectively responsible for almost 40% of the global trade.

In one of the alternative futures where the difference in WACC between countries slowly became smaller, global trade volumes as a whole would become slightly lower (15.5 EJ/year) but would otherwise not be greatly affected; however, the outlook for specific countries would be drastically different. The trade volumes and patterns are dependent on the geographical resolution used in the model. As regions are disaggregated into individual countries, more extreme hydrogen production cost values are possible, potentially leading to new trading countries.

The cost of producing green hydrogen from solar PV and solar–onshore wind hybrid configurations is projected to drop below USD 1 (US dollars) per kilogramme of hydrogen ($kgH_2$) for most regions by 2050 when *optimistic* assumptions are used (see note under Figure 0.2), going up to over USD 1.3/$kgH_2$ with *pessimistic* assumptions[2] for PV and electrolyser cost. Over the same time frame, the cost of shipping ammonia is projected to decline by one order of magnitude, from USD 8/$kgH_2$ to USD 0.8/$kgH_2$ (based on 20 000 kilometres) (IRENA, 2022b). At these price levels (USD 1.5-2/kg for delivered hydrogen), the prices charged by different exporters should be very close to one another, giving most countries multiple potential trading partners at a small switching cost penalty. Thus, trading partners will probably not be defined exclusively by cost, but rather by a combination of cost, energy security and other geopolitical factors (IRENA, 2022d).

Multiple dimensions need to work in synergy for the hydrogen trade to take off. First, a market needs to be created, which would include generating demand, promoting transparency and bringing suppliers and end users together. Also essential would be a market regulatory framework that is flexible enough to enable growth and be adaptive but that is not so loose that it compromises sustainability or cost-effectiveness. Second, a certification scheme is needed that is consistent across borders and has an internationally agreed methodology (IRENA, 2020a). Initially, the certification could focus on hydrogen production and emissions reduction, but it would ultimately need to include commodities and social dimensions related to a just energy transition. Third, the required technology needs to be developed and improved. Although a large part of the projected cost decrease can be achieved by scaling up hydrogen production, (re)conversion and transportation processes, innovation is also needed to improve the technologies and to demonstrate the operation of the entire integrated value chain, from renewable energy to hydrogen production, infrastructure and end use. Fourth, financing needs to be deployed to construct the infrastructure required both for global trade and for much larger-scale upstream renewable energy generation; the latter representing the largest share of total investment needs.

For large-scale hydrogen production and trade to be a viable component of the 1.5°C scenario, the electricity used to produce the hydrogen must not detract from the availability of electricity for other essential and more effective uses – it must be additional. This places the upscaling and acceleration of renewable energy generation at the heart of the transition to green hydrogen. The production of renewable energy needs to at least triple from today's 290 gigawatts (GW) per year to more than 1 terawatt (TW) per year by the mid-2030s. Over 10 000 GW of wind and solar power would be needed by 2050, just for green hydrogen production and trade.

[2] *Capital expenditure assumptions for the pessimistic scenario: PV: USD 271-551/kW; onshore wind: USD 775-1191/kW; offshore wind: USD 1317-1799/kW; electrolyser: USD 307/kW.*

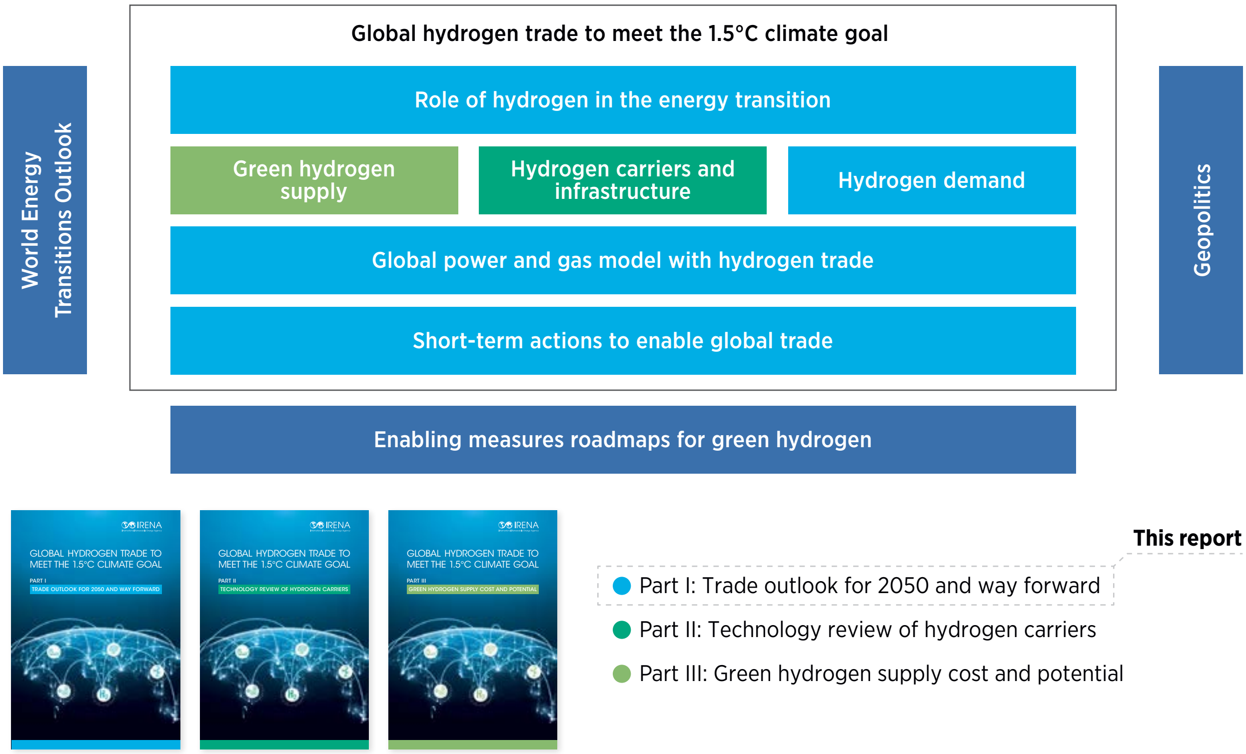
To give a sense of the scale needed, total wind and solar generation was 1612 GW in 2021, and none of it was for hydrogen. In addition, installed electrolyser capacity would need to grow from its 2021 level of 700 megawatts (Rystad Energy, 2021) to 4-5 TW by 2050.

Today, only very limited amounts of (grey) hydrogen are transported in pure hydrogen form. Even in the 1.5°C scenario, almost three-quarters of the hydrogen produced would be used as methanol, steel, ammonia (for fuel and feedstock), and synthetic fuels for aviation. Most of the ammonia trade would be for direct consumption as ammonia, instead of being converted back into hydrogen. Hydrogen conversion into iron and synthetic fuels would be even more attractive as both have lower transportation costs than hydrogen or ammonia. These two commodities cannot be converted back into hydrogen, but there is no need for reconversion since there is a large demand for them as well as an existing global infrastructure that would not require changes, except – fundamentally – for the commodities to be produced using green hydrogen instead of fossil fuels. This will be explored further in future IRENA analysis.

# CONTEXT OF THIS REPORT AND WHAT TO EXPECT

This report is part of a series of three reports focusing on the *Global Hydrogen Trade to Meet the 1.5°C Climate Goal* (see Figure 0.1). The first one (this report) integrates all the components – supply and infrastructure from the other two reports in the series, together with demand from IRENA's *World Energy Transitions Outlook 2022* 1.5°C scenario (IRENA, 2022a) – to assess the outlook of global hydrogen trade by 2050, looking at the cost and technical production potential of green hydrogen for the world in 2030 and 2050 under different scenarios and assumptions. The second report looks at the state-of-the-art from the literature about hydrogen infrastructure under four technology pathways (IRENA, 2022b). The third report covers the cost and technical potential of green hydrogen supply for various regions and time horizons under different scenarios and assumptions (IRENA, 2022c).

**FIGURE 0.2. Scope of this report series in the broader context of IRENA publications**




The *Global Hydrogen Trade to Meet the 1.5°C Climate Goal* report series is closely related to some recent IRENA publications. The *World Energy Transitions Outlook 2022* (IRENA, 2022a) provides a perspective on the role of hydrogen within the wider energy transition in a scenario in line with a 1.5°C pathway. This outlook includes all the energy sectors as well as the trade-off between hydrogen and other technology pathways (*e.g.* electrification, carbon capture and storage, bioenergy). The short-term actions required to enable global trade identified in the *Global Hydrogen Trade to Meet the 1.5°C Climate Goal* report series are only the beginning. While there are measures that are applicable at the global level (*e.g.* certification), some measures will be specific to a country, being dependent on local conditions such as energy mix, natural resources and level of mitigation ambition. Thus, the global toolbox of enabling measures needs to be adapted to the local context. IRENA has already done this for Europe and Japan (IRENA, 2021a), and more regions will be analysed in 2022.

Hydrogen trade will not just be defined by production and transport cost or by comparison of domestic production versus import cost. Other factors – energy security, existence of well-established trade and diplomatic relationships, existing infrastructure, and stability of the political system, among others – will also have a large impact on the trade partners each country chooses to have. However, these "soft factors" are not considered in this report, which is instead focused on providing a cost-based perspective on trade potential from a purely techno-economic angle. Therefore, actual trade partners may look different from the ones presented here. The geopolitical factors are covered in a separate report (IRENA, 2022d) as part of IRENA's Collaborative Framework on Geopolitics.

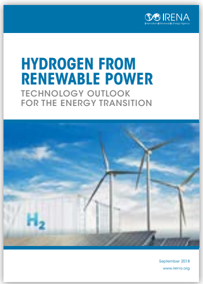
Chapter 1 of this report covers the broader aspects that should be considered for global hydrogen trade, beyond costs, and how various recent announcements give signs that hydrogen trade might be developing rapidly. This is useful for readers looking to understand the broader context around hydrogen trade, its drivers, and factors to consider.

Chapter 2 breaks down global hydrogen demand by sector and country to be able to relate with supply (from Part III of this report series) (IRENA, 2022c) and transport cost (from Part II of this series) (IRENA, 2022b). The share of hydrogen trade in 2050 is directly dependent on hydrogen demand and applications, as presented in IRENA's *World Energy Transitions Outlook* 1.5°C scenario.

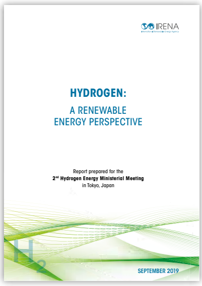
Chapter 3 looks in detail at the hydrogen trade, analysing global trends and the role of specific countries. It starts with the fundamental drivers of trade that are applicable beyond the modelling exercise done and captures the main areas of uncertainty. It also covers the potential trade of a hydrogen-derived commodity (ammonia), which might present better opportunities than trade in hydrogen itself (other commodities, such as reduced iron, synthetic fuels and methanol, are excluded). It then covers the renewable hydrogen production for various scenarios, establishing the relationship with the technical potentials identified in Part III of this series (IRENA, 2022c). This is followed by the trade outlook for the reference scenario and the investment needed for such a future. Lastly, alternative scenarios for the most influential parameters are explored to understand the vulnerabilities of some regions to different pathways towards 2050. In addition to the results and sensitivities of this specific modelling exercise, this chapter examines the relationships between parameters that shed light on the underlying drivers of the hydrogen trade, beyond the numerical results of this exercise. The analysis focuses on electrolytic hydrogen using renewable energy.

Chapter 4 identifies some of the main barriers that hinder global trade today and that need to be tackled for this market to emerge. Multiple solutions are identified, and actionable items for the short term are defined to enable the presented 2050 scenarios. This chapter is targeted towards policy makers and readers looking at the broader perspective of trade. The information provided falls between the techno-economic analysis and the geopolitical factors, where action is needed to enable global trade.

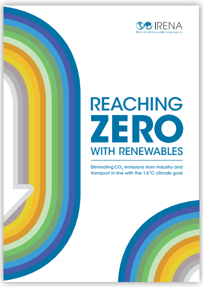
This report is part of IRENA's ongoing programme of work to provide its member countries and the broader community with expert analytical insights into the potential options, enabling conditions and policies that could deliver deep decarbonisation of economies. Green hydrogen, being an indispensable element of the energy transition, is one focus of IRENA analysis. Recent IRENA publications relating to this subject include the following (all can be found on IRENA's Publications page: www.irena.org/publications):



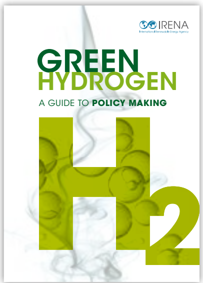

Hydrogen from Renewable Power (2018)



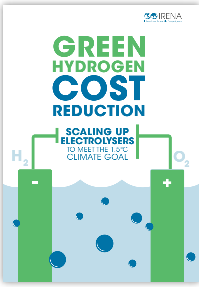

Hydrogen: A renewable energy perspective (2019)



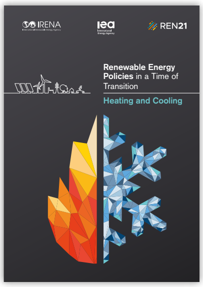

Reaching Zero with Renewables (2020) and its supporting briefs on industry and transport



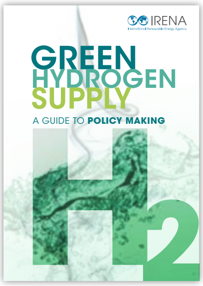

Green Hydrogen: A guide to policy making (2020)




Green Hydrogen Cost Reduction: Scaling up electrolysers to meet the 1.5°C climate goal (2020)

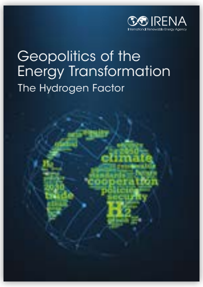



Renewable Energy Policies in a Time of Transition: Heating and cooling (2020)

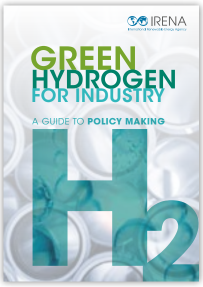



Green Hydrogen Supply: A guide to policy making (2021)


Enabling Measures Roadmap for Green Hydrogen (2021), in collaboration with the World Economic Forum




Geopolitics of the Energy Transformation: The Hydrogen Factor (2022)




Green Hydrogen for Industry: A guide to policy making (2022).

These reports complement IRENA's work on renewables-based electrification, biofuels and synthetic fuels, and specific applications where molecules are better placed for decarbonisation.

Results of this analysis are also briefly presented in the *World energy transitions outlook* 2022, chapter 5.3 (IRENA, 2022a).

This analytical work is supported by IRENA's initiatives to convene experts and stakeholders, including IRENA Innovation Weeks, IRENA Policy Days and Policy Talks, and the IRENA Collaborative Framework on Green Hydrogen. These initiatives bring together a broad range of member countries and other stakeholders to exchange knowledge and experience.

# 1 INTRODUCTION

# INTRODUCTION

## Highlights

In the *World Energy Transitions Outlook* 1.5°C scenario, 70% of the carbon dioxide emission reductions towards a net-zero system can be achieved through electrification, energy efficiency and renewables. Hydrogen will be needed to achieve full decarbonisation. It is a complement to electrification, offering a solution for heavy industry, long-haul transport and seasonal storage, which are applications where molecules will be needed. In this 1.5°C scenario, the global hydrogen production would need to expand by almost five times, to 614 megatonnes of hydrogen per year, to reach 12% of final energy demand by 2050, also shifting from a major source of greenhouse gas emissions to a low-emission energy carrier. Green hydrogen, produced from renewables, is expected to represent the bulk of the production.

Not all countries are equally endowed with renewable resources. Hydrogen and its derivatives can provide a cost-effective means to transport energy over long distances and store it for long periods of time. This opens a new opportunity for producing renewable energy, transforming it to hydrogen and transporting it to large demand centres far away. Transporting renewable energy in the form of hydrogen and derivatives effectively increases the distance that renewable energy can travel in a cost-effective way. This will be economically attractive if the transport cost is lower than the production cost differential between two regions.

Hydrogen also offers the possibility of further conversion to other molecules like chemicals, fuels or even materials such as reduced iron, which are generally easier to transport and can rely on existing infrastructure. This broadens the possibilities for using hydrogen to decarbonise traded goods, rather than being traded as an energy carrier, considering its potential for being embedded into other commodities or final products. If the final demand is for ammonia, methanol, synthetic fuels or steel (among others), it is advantageous, from a cost perspective, to transport hydrogen in such a form because hydrogen is much less dense than these derived products, thus resulting in a higher transport cost.

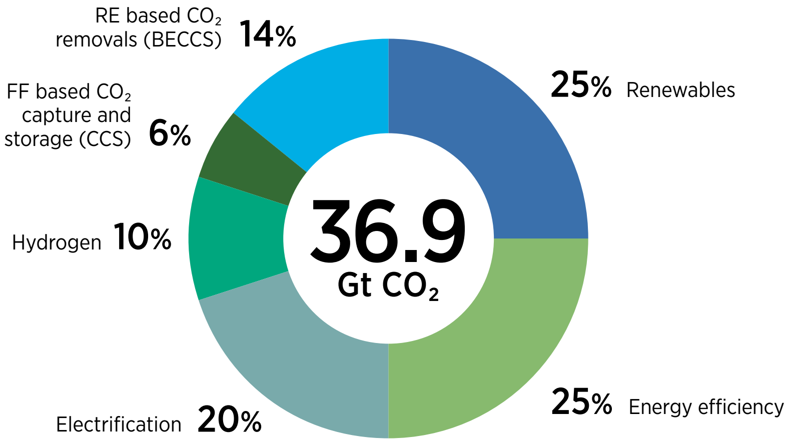
Signs of global trade are emerging, with over 80 announcements between 2020 and 2021 for projects or collaborations that relate to global hydrogen or ammonia trade. Based on these announcements, the most active prospective importers are Germany, Japan and the Netherlands and the most active prospective exporter is Australia.

Global hydrogen trade does not solely depend on the cost differential. Hydrogen exports can offer an opportunity for oil-based economies to diversify, countries with vast renewable resources to acquire a more prominent role in the global energy landscape, and countries with technology knowledge to provide the expertise to develop new facilities. It also provides opportunities for importing countries to diversify suppliers and decrease the costs of transitioning to lower emissions. These relationships will also be defined by existing partnerships and alliances, bilateral relations and the state of development of the hydrogen industry, among other factors. These factors are outside the scope of this report and are covered in a recent IRENA report on the geopolitics of hydrogen (IRENA, 2022d).

## 1.1 The role of hydrogen in a 1.5°C scenario

The bulk of the decarbonisation of the energy system is expected to come from a combination of renewables in the electricity system, electrification of end-use sectors (especially road transport and low-temperature heating) and energy efficiency. In the 1.5°C scenario of the *World Energy Transitions Outlook* (WETO) from IRENA, these three strategies are expected to achieve 70% of the carbon dioxide ($CO_2$) reduction towards 2050 (see Figure 1.1).

**FIGURE 1.1. Carbon emission abatements under the 1.5°C scenario**



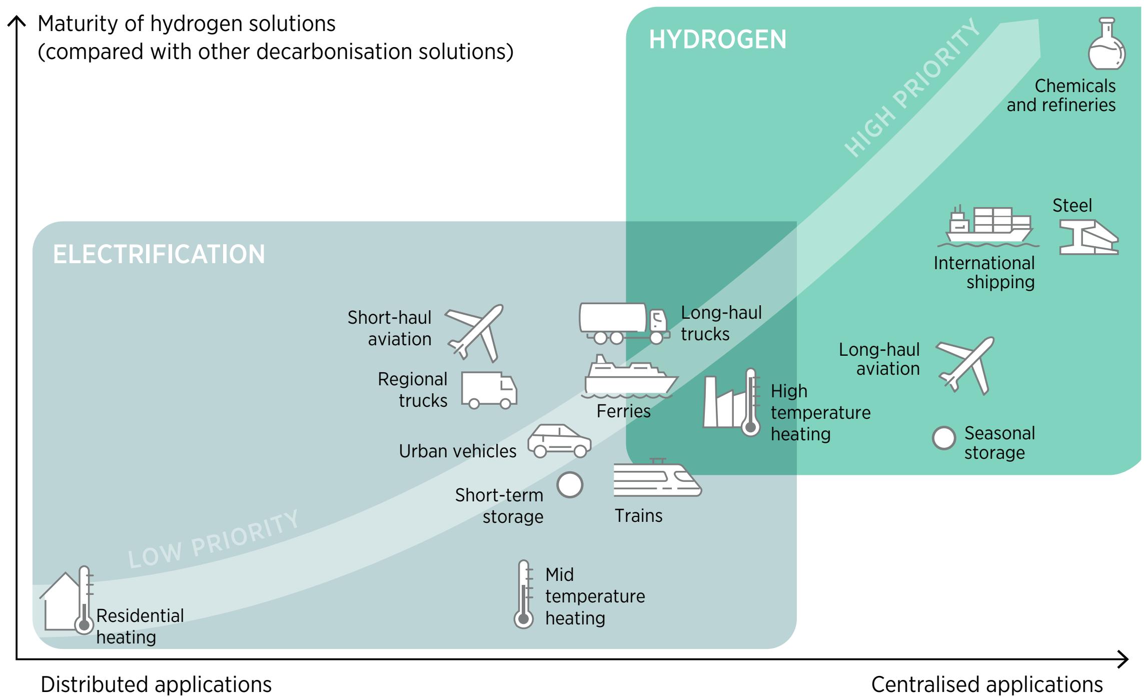

Note: BECCS = bioenergy with carbon capture and storage ; FF = fossil fuel; RE = renewable energy.
Source: IRENA (2022a).

Not all applications can be electrified, or at least not in the short term (*e.g.* international shipping and aviation), and a denser form of energy is needed. Furthermore, there are applications where molecules are needed as a feedstock rather than an energy carrier, and electricity does not represent a feasible substitute. Gaseous and liquid carriers are easier to store in large quantities and transport over long distances than electricity, resulting in a lower cost. Considering these factors, hydrogen is expected to satisfy 12% of final energy demand[3] and contribute to a reduction of 10% of the total $CO_2$ emissions in this 1.5°C scenario, which together with carbon capture and storage (CCS) and negative emission technologies paves the way for achieving a net-zero emissions energy system (IRENA, 2022a).

Hydrogen is used today predominantly as an industrial feedstock for ammonia, methanol and refineries and as part of a mix of gases in steel and industrial heat generation. Dedicated hydrogen production is around 87 megatonnes of hydrogen per year ($MtH_2$/year), equivalent to about 2.5% of the final energy demand in 2020 (IEA, 2021a). Roughly three-quarters of this hydrogen is produced from natural gas, and the remaining quarter from coal.[4] The $CO_2$ emissions associated with this production are about 800 megatonnes of carbon dioxide ($MtCO_2$/year), equivalent to almost 2.2% of the global energy-related $CO_2$ emissions. Another 35-40 $MtH_2$/year are produced as part of a mix of gases, to reach a total of about 125 $MtH_2$/year.

Hydrogen can be used across the entire energy system. However, any green hydrogen use beyond the industrial sector translates into larger (renewable) capacities needing to be deployed, larger investments, and a higher hurdle to overcome. For some applications, like low- and mid-temperature heating or road transport, electrification is not only more efficient but more cost-effective and can lead to decarbonisation today with available technologies (Knobloch *et al.*, 2020). Hydrogen is then left for applications that have limited choices or in which electrification is difficult, such as international shipping and aviation, chemicals, steel and seasonal storage (see Figure 1.2). For most of these applications, hydrogen itself is not the most attractive form of energy from a cost perspective; a hydrogen derivative (*i.e.* ammonia, synthetic fuels, reduced iron) is more attractive. Industrial and power applications have the advantage that the typical demand size can enable economies of scale for production and infrastructure, as opposed to transport applications, which need to aggregate large numbers of end users.

**FIGURE 1.2. Priority settings for hydrogen applications across the energy system**




Source: IRENA (2022e).

[3] *Hydrogen demand is 74 EJ/yr, but some of it is used for power generation and non-energy uses in industry which results in only 42 EJ/yr of hydrogen ending up as final energy demand*

[4] *Hydrogen is also produced as a by-product of oil-refining processes, steam-cracking, chlor-alkali, and other chemicals.*

In a decarbonised energy system, as new applications become necessary, the total hydrogen production is expected to expand by almost five times, to 614 $MtH_2$/year, to satisfy 12% of the final energy demand by 2050 in a 1.5°C scenario. This is driven by growth in the industrial and transport sectors, where hydrogen mitigates close to 12% and 26% of the $CO_2$ emissions, respectively (IRENA, 2022a). To achieve this growth, focus on hydrogen should be broadened to cover hydrogen derivatives such as ammonia, methanol and synthetic fuels, which are easier to transport and store than hydrogen itself and are more suitable for specific applications (*e.g.* shipping, aviation). This transformation also takes place on the supply side, where the production shifts from being fossil-based to reach two-thirds being generated with renewable electricity ("green hydrogen") and one-third from fossil fuels with CCS ("blue hydrogen") (IRENA, 2022a). Another emerging pathway is methane pyrolysis ("turquoise hydrogen") (Box 1.1).

**Box 1.1. Methane pyrolysis as an alternative route for low-carbon hydrogen production**

An intermediate shade between blue and green hydrogen is "turquoise" (methane pyrolysis). This pathway combines the use of natural gas as feedstock with no $CO_2$ production. The carbon in the methane instead ends up as solid carbon. A market for carbon black already exists and would provide an additional revenue stream (USD 0.5-2 per kilogramme of carbon).* Thus, the hydrogen cost is dependent on the natural gas and carbon black prices. The existing market is mainly for rubber (tyres), and saturating this market with turquoise hydrogen would lead to the co-production of about 5 $MtH_2$/year (or about 7% of current global pure hydrogen production) (Parkinson *et al.*, 2019). In the future, new markets such as graphite for batteries, graphene, or integration into steel making could arise, and in the worst case, the solid carbon could be stored in much lower volumes than $CO_2$ (due to its physical state). Solid carbon is also a safer long-term storage medium for $CO_2$, effectively eliminating concerns about potential $CO_2$ leaks from underground reservoirs and the associated risks, as well as the bulk of costs for monitoring and certification systems of long-term (gaseous) $CO_2$ storage.

Methane decomposition can be mainly achieved through three routes – thermal (1000°C), plasma (2000°C) and catalytic (well below 1000°C) – and there are different types of reactors for each, with different technology maturity. The most mature are plasma technologies, with a technology-readiness level between 5 and 8, while thermal and catalytic processes have a technology-readiness level of 3-4 (Schneider *et al.*, 2020). A plant from Monolith with a capacity of 14000 tonnes of carbon black per year came into operation in 2021 in Nebraska (United States of America). Monolith has also received USD 1 billion in funding from the US Department of Energy, which will allow 12 more of these units to be constructed. New plants from Monolith are expected to start construction in 2022, with full capacity reached in 2026 (Greenwood, 2022). There are also other plants under construction in Canada and the United States. A demonstration project, with a capacity of 100 tonnes of hydrogen per year, has received funding from the Australian Renewable Energy Agency, and it is expected to start operation in 2022. Companies in Australia, France, Germany, the Netherlands, and the Russian Federation are looking into such projects (Philibert, 2020).

The process uses about four to five times less electricity than electrolysis. However, it only has an efficiency of 53-55% (lower heating value) and a higher capital cost than electrolysis or steam methane reforming (Pöyry, 2019). Another disadvantage of this pathway is the quality of both the hydrogen and the carbon. Hydrogen would need further purification to be used in fuel cells.

*About 3 tonnes of carbon black are produced per tonne of hydrogen.

Electrolysis is the process through which low-cost renewable electricity can be used to split water into hydrogen and oxygen. This would allow the continuous cost decline of renewable electricity to be taken advantage of (IRENA, 2021b), providing flexibility to the power system to be able to integrate more renewables and providing a means to decarbonise applications for which electrification is difficult. Electrolyser capacity needs to grow from the current 700 megawatts (MW) to 4-5 terawatts (TW) by 2050, which would require a peak installation pace of almost 400 gigawatts (GW) per year (IRENA, 2020b). To put this in perspective, the global renewable capacity (including hydropower) deployment in 2021 was lower than this pace, at 290 GW/year, and solar photovoltaic (PV) has taken 19 years (from 2001 to 2020) to go from 700 MW to 714 GW (BP, 2021). Producing all this hydrogen would require about 20 800 terawatt-hours (TWh) of electricity in 2050, equivalent to about 80% of global electricity generation today, but about 23% of the 90 000 TWh/year of a net-zero emissions energy system (IRENA, 2022a).

Going forward, only low-carbon hydrogen facilities should be constructed. This means unabated production from gas and coal is not an option, which leaves only green and blue hydrogen. One of the challenges green hydrogen faces is the production cost differential compared with fossil-based routes. In the coming years, the gap between blue and green hydrogen can be closed by the ongoing decline in the cost of renewable electricity (which is the main cost driver), strategies to reduce the cost of the electrolyser (IRENA, 2020b), and policy support (IRENA, 2021c). These fundamental drivers will lead green hydrogen to outcompete blue hydrogen in the coming five to ten years, similar to what has already happened today with renewables in the electricity system (IRENA, 2021b). However, a key advantage for green hydrogen is that a large share could come from off-grid dedicated plants, with long-term purchase agreements that fix the hydrogen production cost. In contrast, the main cost contributor to blue hydrogen is the natural gas input; this price is subject to sudden fluctuations such as the ones experienced in Asian markets, and particularly in Europe, in late 2021. This can make green hydrogen attractive in a much shorter time frame, especially when combined with $CO_2$ prices above USD 90 (US dollars) per tonne of $CO_2$ ($tCO_2$), which were already reached in the European Union (EU) in early 2022.

## 1.2 Hydrogen as an opportunity to connect renewables-rich regions with demand centres

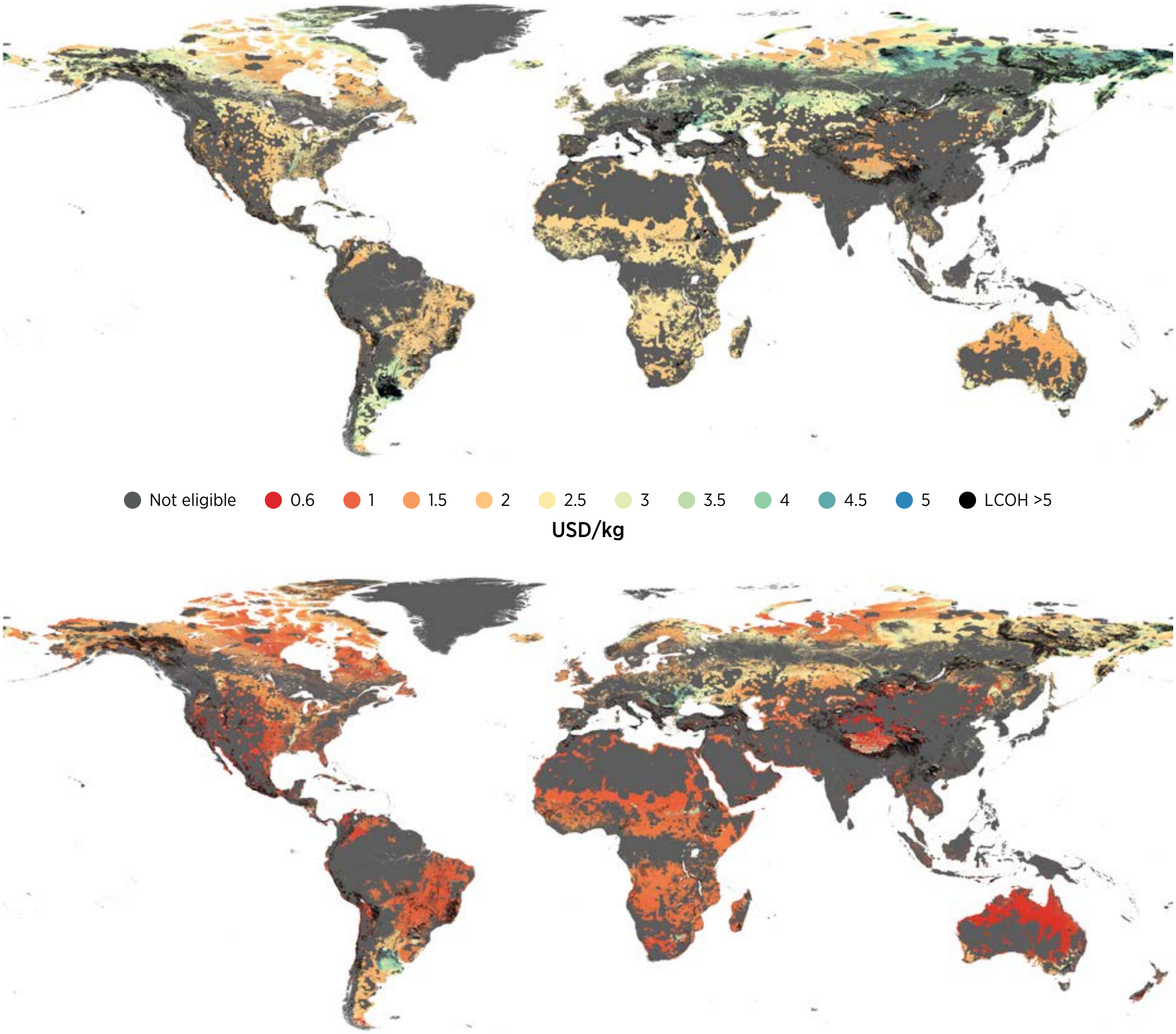
The global energy demand today is 80% supplied by fossil fuels. Fossil fuel reserves are highly concentrated in a few countries, with the top five countries[5] holding 62% and 64% of the global oil and gas reserves, respectively (BP, 2021). This leads to a market dominated by a few countries, which has historically led to price spikes in cases of supply disruptions. Instead, in a decarbonised energy system largely supplied by renewables, there is a limited concentration of energy supply since every country has the potential to generate renewable energy to various degrees and of various types. There is a change from energy stocks (*i.e.* fossil fuels reserves) to energy flows, from continuous expenditure for importing fuels to capital expenditure (CAPEX) on assets with low marginal production cost, and from large centralised facilities to plants that can be deployed at virtually any scale (*e.g.* solar PV) (IRENA, 2019).

In a 1.5°C scenario, renewables are expected to supply 90% of electricity generation in 2050, with wind and solar alone representing 63% of the total. Countries are not all equally endowed with such resources, so the quality and production costs of the resources vary greatly among

[5] *Canada, the Islamic Republic of Iran, Iraq, Saudi Arabia and the Bolivarian Republic of Venezuela for oil and the Islamic Republic of Iran, Qatar, the Russian Federation, Turkmenistan and the United States of America for gas.*

countries (see Figure 1.3). The opportunity that hydrogen provides in this context is that, by using electrolysis, it transforms the renewable electricity into an energy form more suitable for long-distance transport, decreasing the transport cost per kilometre (km). This effectively extends the distance that the energy can be transported for the same cost. The competitiveness is, then, weighted on the production cost differential between regions versus the additional cost of transport. The choice is further complicated by the possibility of transforming hydrogen into derivatives before shipment. Hence, hydrogen can be transported in the form a carrier from which pure hydrogen is obtained at the end or in the form of a commodity or material that would not be reconverted back to hydrogen (*e.g.* direct reduced iron [DRI], steel, ammonia, synthetic fuels).

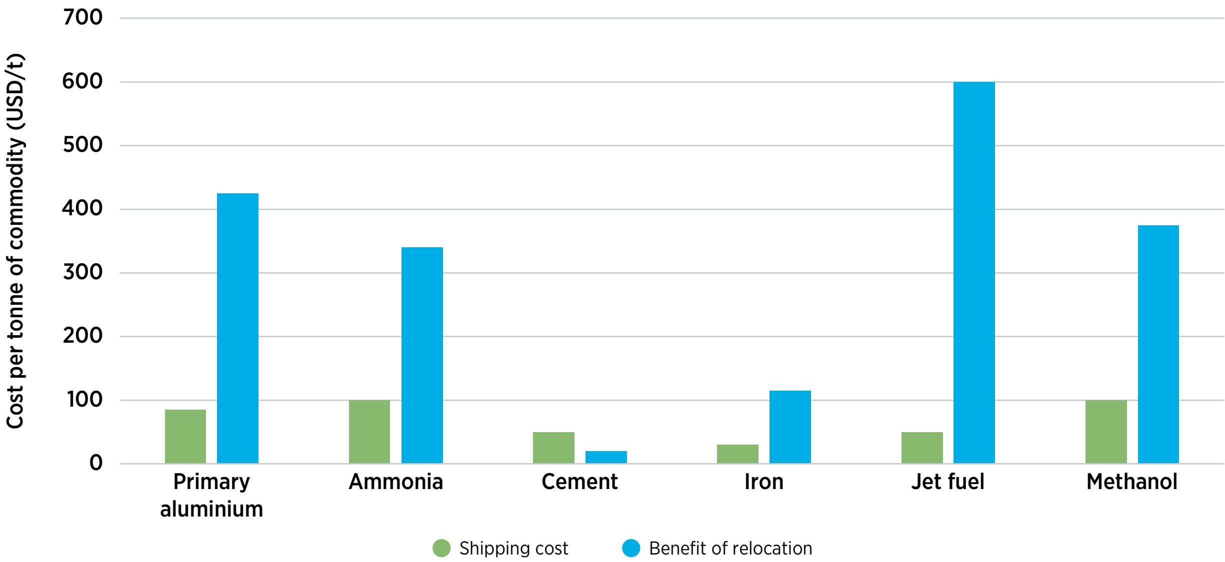
**FIGURE 1.3. Global levelised cost of hydrogen (LCOH) in 2030 (top) and 2050 (bottom)**




Note: Assumptions for capital expenditure are as follows: solar photovoltaic (PV): USD 270-690/kW in 2030 and USD 225-455/kW in 2050; onshore wind: USD 790-1435/kW in 2030 and USD 700-1070/kW in 2050; offshore wind: USD 1730-2700/kW in 2030 and USD 1275-1745/kW in 2050; electrolyser: USD 380/kW in 2030 and USD 130/kW in 2050. Weighted average cost of capital: Per 2020 values without technology risks across regions. Land availability considers several exclusion zones (protected areas, forests, permanent wetlands, croplands, urban areas, slope of 5% [PV] and 20% [onshore wind], population density, and water availability). Refer to IRENA (2022c) for more details.
*Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.*
Source: IRENA (2022c).

One of the main parameters defining the economic benefit of relocating production of hydrogen-based commodities is the difference in renewable electricity cost. In 2020, based on actual projects, the difference in the weighted average levelised cost of electricity for solar PV between the cheapest and most expensive regions was almost a factor of four, with the 5th percentile of costs at USD 39 per megawatt-hour (MWh) and the 95th percentile at USD 163/MWh. This was less pronounced for onshore wind, with a factor of 2.4, from USD 29/MWh to USD 70/MWh (IRENA, 2021b). In the future, this cost differential is expected to go down due to two factors: (1) the capital cost gap between regions closing as more countries develop domestic experience and exchange lessons learned, and the entire supply chain is scaled up, and (2) the cost of capital and the risk associated with building these facilities decreasing. Thus, the future cost differential will be mostly driven by the difference in resource quality and by the cost of capital differential due to the economic conditions of each country (*i.e.* country risk). A conservative resource quality differential of a factor of two can translate into an electricity cost difference of USD 30/MWh.[6] This can be higher if hybrid PV-wind-battery plants are used, but this level would already be enough to justify the relocation of the production of various commodities (see Figure 1.4).

**FIGURE 1.4. Economic benefit of relocating production of various fuels and commodities to places with low renewable energy cost compared with shipping cost by 2030**




Note: Energy cost benefits have been calculated by multiplying energy intensity with cost savings per unit of energy. Shipping cost data were taken from recent market surveys and are based on current typical sizes. For methanol and ammonia, costs could be even lower if larger ships (than today) are used. Shipping costs are indicative as they tend to fluctuate strongly based on the supply and demand balance. The estimated benefit of relocation is based on a differential of USD 30/MWh for electricity and USD 5/GJ for thermal energy between the exporting and importing region.
Source: Gielen *et al.* (2021).

The largest economic benefit for relocation is for jet fuel due to compounding factors. First, 50-65% of the energy input is lost when transforming the renewable electricity into jet fuel, which means the initial energy cost is doubled or tripled (Burkhardt, Bock and Bier, 2018; Hansson *et al.*, 2017). This makes the use of low-cost electricity imperative. Second, jet fuel has a low transport cost, which means it is easy to move from a region with low-cost energy to a region with high-cost energy. The transport cost per unit of distance and energy of an oil tanker is about five to six times lower than natural gas pipelines and 40-60 times lower than electricity transmission lines (Saadi, Lewis and McFarland, 2018).

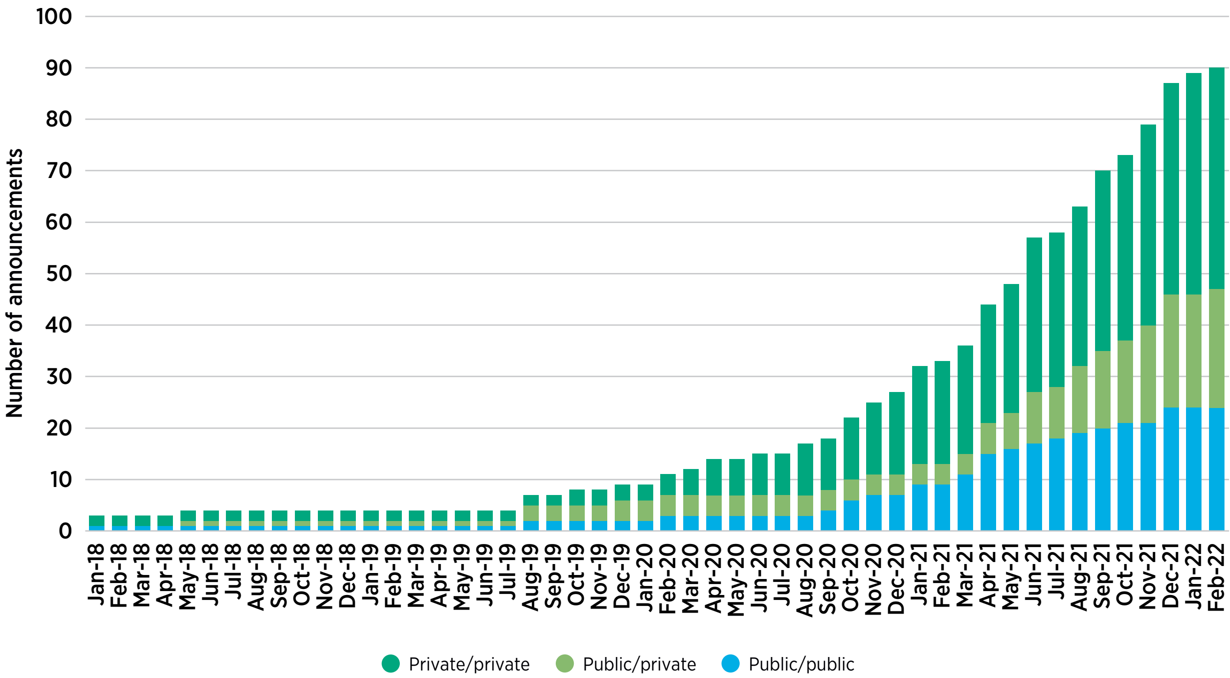
[6] *Measured by the full load operating hours over a year for the same installed capacity. The actual effect on electricity price will depend on the capital cost, cost of capital and other factors, but USD 30/MWh is used for illustration purposes.*

At the other extreme, there is cement, which can have a higher transport cost than production cost, and that is usually why the production is located close to the demand. Between these two extremes, the economic impact of relocating the production of other commodities is largely positive. From a purely cost perspective, it makes the most sense to produce them in places with good renewable resources and transport the commodity rather than transporting the renewable energy or the hydrogen (Philibert, 2021). Studies for steel production in Australia and Europe have found this to be the case (Devlin and Yang, 2022; Toktarova *et al.*, 2022). From these commodities, ammonia is the only one that could be reconverted to pure hydrogen at the importing side, if required, and without any carbon emissions.[7]

## 1.3 Early signs of global trade

Between late 2019 and January 2022, 15 countries and the European Commission published hydrogen strategies. One of the most common dimensions covered has been international collaboration, from the perspective of knowledge exchange and lessons learned, but also for potential future trade. Many of these strategies have translated into actual agreements, feasibility studies, memoranda of co-operation or similar. Announcements fall broadly in two categories: general technology collaboration for knowledge exchange, and specific pilot projects or studies for hydrogen trade across borders. Figure 1.5 shows the trend of the announcements since 2018 for the latter category. While there were limited developments until mid-2020, the tally has quadrupled from 12 to 49 in a matter of 13 months (May 2020 to June 2021) and doubled again (to almost 90) in 9 months. This is in line with the growth of hydrogen strategies, yet with a lag of six to nine months, which is a sign that some of the areas identified in the strategies are being followed with more concrete actions.

**FIGURE 1.5. Cumulative number of announcements of agreements for hydrogen trade since the beginning of 2018**

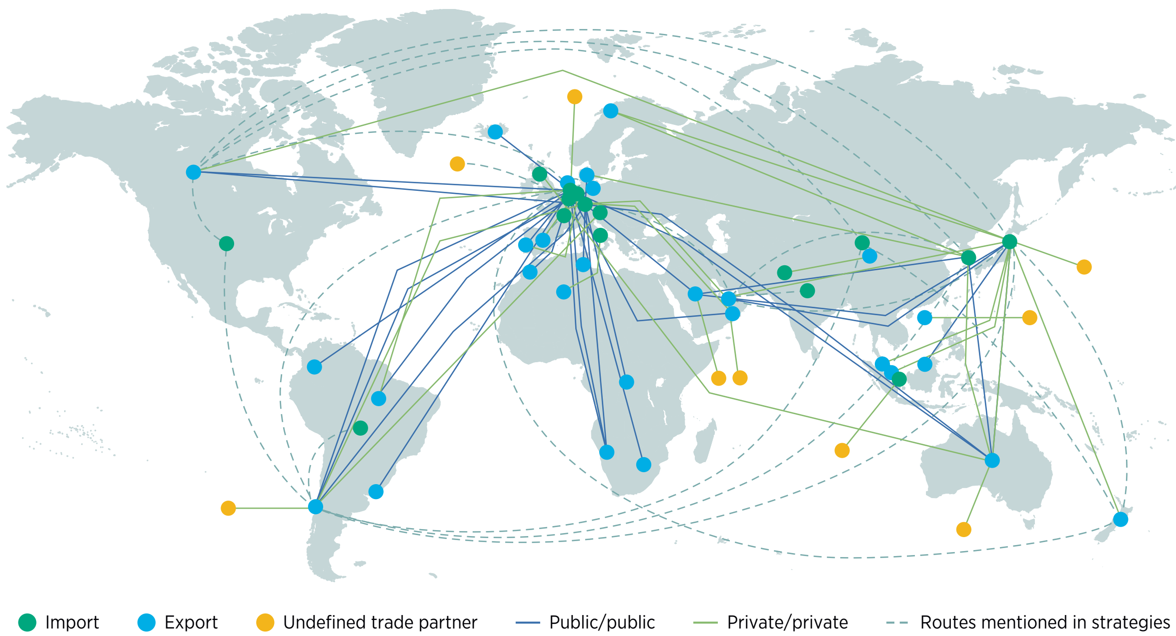



Note: This count excludes agreements that were for hydrogen technologies in general and did not mention trade explicitly.

[7] *Methanol could also be reconverted, but since it is a carbon-containing carrier there would be some $CO_2$ release upon reconversion and the round-trip efficiency might be in the order of one-third.*

When looking at the countries involved in these announcements (see Figure 1.6), Germany, Japan and the Netherlands have been some of the most active as potential importers. A combination of limited domestic potential, restrictions on technology choices (*e.g.* nuclear, CCS) and relatively poor renewable resources leads to a promising outlook for importing renewable energy despite the additional transport cost. At the same time, the need for energy security and the uncertainty associated with future technology development has led to a diversification approach in two aspects: (1) in establishing relationships with multiple countries in case there are unforeseen events that prevent the local development of the hydrogen industry and (2) in testing multiple hydrogen carriers since there is not a clear winner yet and all pathways need further development before being fully proven at commercial scale. Germany has allocated EUR 2 billion (euros) from the COVID-19 recovery package to international partnerships (not all of this for trade), EUR 900 million of which is allocated to support the import of hydrogen to Germany through the H2Global initiative (see Box 1.3). Other countries that have also been active on the importing side are the Netherlands, especially through the Port of Rotterdam (see Box 1.2), which is the largest port in Europe (and the largest in the world outside China). Singapore has also been active in considering its role as a regional trading hub for Asia. China has focused on the road transport sector and technology leadership but has not announced any plans on hydrogen trade.

**FIGURE 1.6. Bilateral trade announcements for global hydrogen trade until March 2022**




Map source: Natural Earth, 2021.
Note: Information on this figure is based on that contained in government documents at the time of writing.

Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply any endorsement or acceptance by IRENA.

On the exporting side, the picture is much more diverse. The exporting archetype ranges from countries that import energy today but that have rich renewable resources that may allow them to become an energy exporter (*e.g.* Chile, Morocco, Portugal, Spain), to energy exporters today that also have rich renewable resources and are aiming to pivot from economies that rely on fossil fuel exports to a low-carbon economy (*e.g.* Australia, Canada, Middle East countries), to regions that already have a high renewable share in their electricity mix and are aiming to export renewable hydrogen (*e.g.* Australia, New Zealand, Norway, Uruguay, and some provinces in Canada). This broader cohort of countries creates more possibilities to test different configurations and conditions to enable faster learning and optimisation of plant design. When looking at the (preliminary) technology choices for these announcements, almost three-quarters are planning to use electrolytic hydrogen, predominantly from hybrid configurations of solar PV and onshore wind,[8] with ammonia the most common energy carrier being considered.[9] Most of the projects are at the stage of performing a (pre-)feasibility study or signing a memorandum of understanding and are still years away from a final investment decision, which translates into high uncertainty about which specific announcements will materialise. The largest project so far is the Western Green Energy Hub in the southeast of Western Australia, which includes 50 GW of renewable generation (30 GW of onshore wind and 20 GW of PV), with a total cost of about AUD 100 billion (Australian dollars), approximately USD 72.3 billion, to produce 3.5 $MtH_2$/year or 20 Mt of ammonia per year, aiming for first production in 2030 (Readfearn, 2021).

**Box 1.2. Hydrogen imports to Europe through the Port of Rotterdam**

The Port of Rotterdam trades 8 800 petajoules (PJ) of energy annually, which is equivalent to three times the Netherland's energy demand or about 13% of the European Union energy demand. About 40% of the total throughput of the port in 2020 consisted of fossil fuels. It is the largest port in Europe, with almost a third of the total throughput in Europe. Several conditions make the port attractive as a leading hub for future hydrogen trade: large industrial use of hydrogen (about 1 $MtH_2$ in 2019 [Notermans *et al.*, 2020]), access to offshore wind and underground carbon dioxide storage reservoirs in the North Sea, an existing 1 600 km hydrogen pipeline network, 9 million tonnes per year of liquefied natural gas regasification capacity and an existing natural gas network.

Like other locations, the port is pursuing efforts with multiple hydrogen carriers to develop experience and reduce risk. For ammonia, new dedicated green ammonia terminals will be available by 2025. For liquid organic hydrogen carriers, the first pilot with dibenzyltoluene (DBT) at the existing Botlek terminal is planned for 2023, and other pilot projects are planned before 2030. Koole Terminals, Chiyoda and Mitsubishi also started a feasibility study in August 2021 to import 0.2-0.3 $MtH_2$/year by 2025 and 0.3-0.4 $MtH_2$/year by 2030 using methylcyclohexane (a liquid organic hydrogen carrier), which is expected to be completed in a year. For liquid hydrogen, a feasibility study with Kawasaki Heavy Industries is targeted to start by 2030.

By 2050, the port targets a hydrogen flow of 20 $MtH_2$/year (2 400 PJ), requiring about 200 GW of renewable generation capacity and 100 GW of electrolysis. About one-third (7 $MtH_2$/year) of this demand would be for domestic use, with the rest being exported to the rest of Europe. The intermediate target by 2030 is 6% of this flow, or 1.2 $MtH_2$/year (144 PJ/year), with a larger contribution of blue hydrogen in this closer time horizon of 0.8 $MtH_2$/year. The port is planning to have a hydrogen backbone connecting the industrial facilities inside the port complex by 2025. This will be connected to other industrial hubs in the region through two main efforts: (1) HyWay27, which aims to connect industrial clusters in the Netherlands by 2026 and with the rest of the European network by 2028-2030 and (2) the Delta Corridor, connecting Rotterdam to North-Rhine Westphalia (Germany).

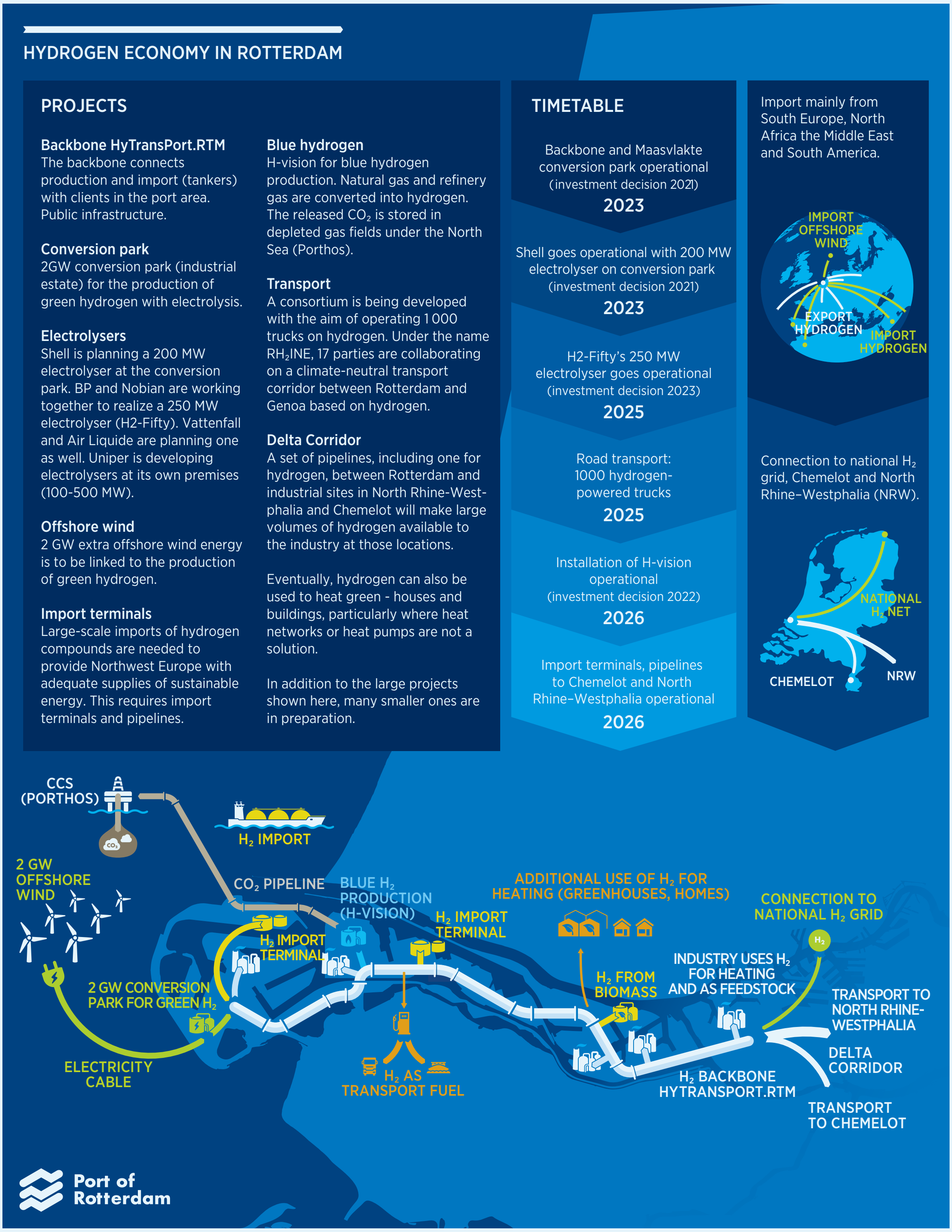
To achieve these targets, various pillars are being tackled, including an import terminal, a conversion park for hydrogen production, offshore wind (2 GW), blue hydrogen (Porthos and H-vision projects), and hydrogen transport (see Figure 1.7).

[8] *Examples of other renewable energy sources are hydropower from Norway and geothermal from Iceland.*

[9] *Most of the announcements do not have explicit statements on the carriers.*

**Box 1.2. (Continued)**

**FIGURE 1.7. Areas of activity for hydrogen in the Port of Rotterdam and milestones until 2030**




Source: Port of Rotterdam.

The port already has agreements in multiple countries to develop potential hydrogen trading routes, including agreements with Australia, Brazil, Canada, Chile, Colombia, Iceland, Morocco, Namibia, Oman, Portugal, Spain, South Africa, United Arab Emirates and Uruguay. The port is also collaborating with parties in Oman for research into green hydrogen.

## 1.4 Soft factors influencing global trade

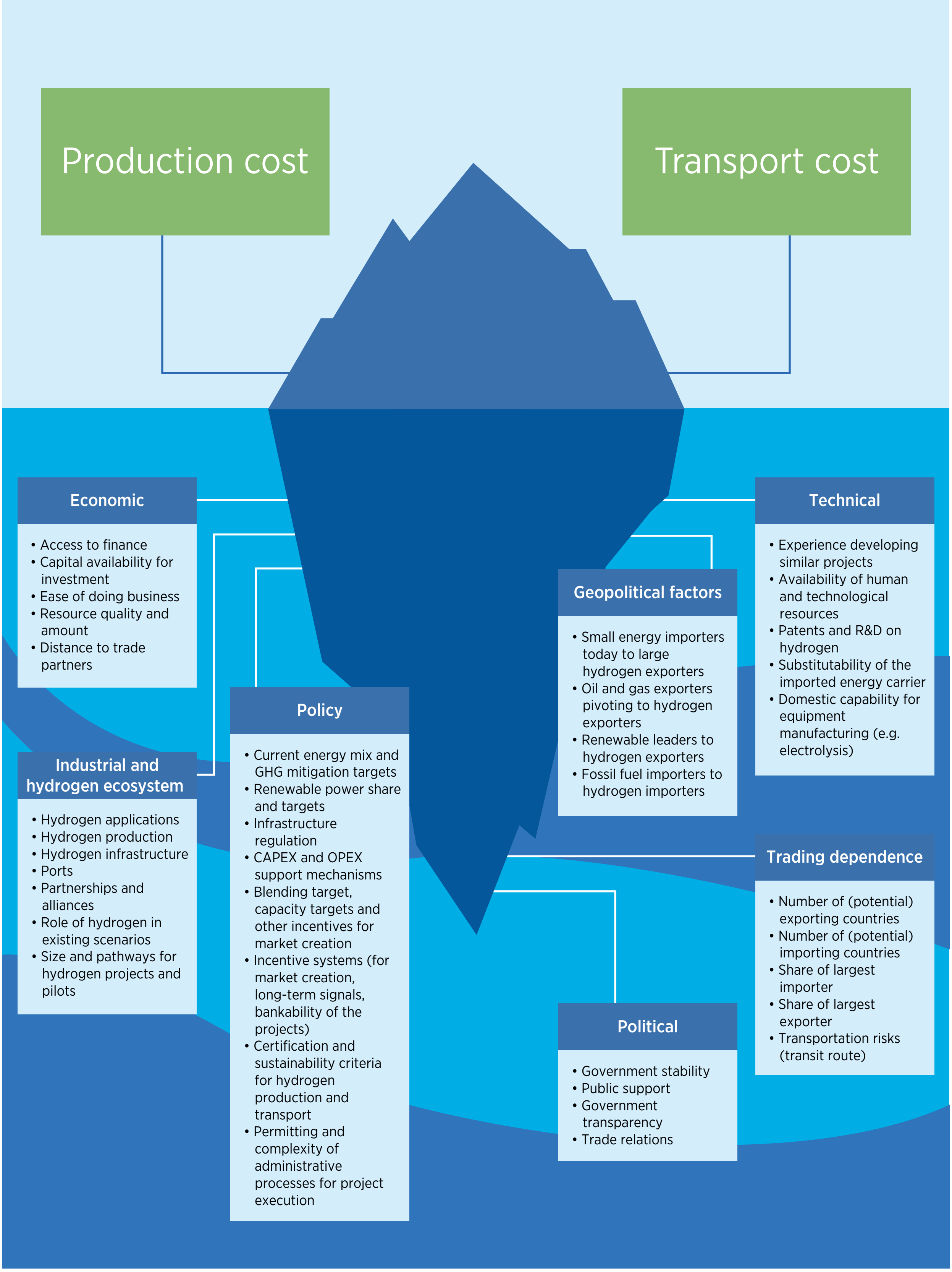
This report mainly focuses on the technical aspects (*e.g.* green hydrogen potential based on land eligibility) and economic aspects (*e.g.* conversion and transport costs) of hydrogen trade. However, other aspects will also influence the technology choice, the development timeline, and the trading partners (IRENA, 2022d). As such, this report is the first step of a two-step approach. First, it is necessary to determine the share of imports by comparing domestic production cost with transport cost, including reconversion. Then, the landed costs from different trading partners are compared to determine the cost-optimal mix for a specific importer. This is, however, only the starting point based on quantitative aspects; there is a wide range of factors that are more difficult to quantify but that potentially have a larger effect on defining the trading pairs in the second step of the process (Figure 1.8). For instance, there is a trade-off between different factors such as the existence of well-established trade and diplomatic relationships, the level of development of the renewable and hydrogen industry, the stability of the political system, and the distance of production and shipping sites, that might justify paying a cost premium for the imported hydrogen. In general, these soft factors effectively alter the output of the economic analysis by shifting the supply and demand curves, resulting in a different trading quantity and different prices (Fraunhofer ISI, 2020).

**Economic factors.** For projects integrated from electricity production to carrier delivery at the port, most of the cost is in the form of investment in facilities; the operating cost is relatively small. This means large amounts of capital are needed to put the facilities in place, making access to finance critical for project development. Hence, countries that have financial institutions with experience in renewable projects as well as lower financing rates, a transparent system for credit information, a strong legal system, low interest rates and a high credit rating for government bonds will be more attractive for the implementation of hydrogen projects. Ease of doing business in the exporting country – including legal support for enforcing contracts and protection of rights, tax incentives, and a regulatory environment to start and operate a company – is also relevant.

**Industrial and hydrogen ecosystem.** This factor includes whether the exporting country has an existing hydrogen industry (and the scale of that industry), if there is already experience with renewable hydrogen, and the size and type of projects that are already ongoing. Another aspect is the hydrogen infrastructure; for instance, if there is an existing gas network that has been assessed for repurposing and that could decrease the local transport cost; if there are suitable underground formations for storage close to the production sites; if there is experience with gas liquefaction; or if there are well-connected ports with large volumes and suitable facilities for hydrogen. A separate dimension is if there is a national alliance or organisation that facilitates the co-ordination of project execution and matchmaking between companies. This is necessary since hydrogen value chains are integrated projects that involve multiple actors and, in most cases, cannot be executed by a single company. Lastly, the role that hydrogen plays in national scenarios is also relevant since it links the potential export with domestic use, potentially providing synergies and a gradual shift from domestic uses to export.

**Policy support.** This factor includes energy policies pursuing ambitious decarbonisation targets (it is only under these conditions that hydrogen becomes attractive from a systems perspective), or dedicated hydrogen policies. Similarly, the development of renewable hydrogen is linked to a high share of renewables in the electricity mix. This high share can be either because the electricity mix is already decarbonised today or because there are clear and ambitious decarbonisation targets for the future. Regarding hydrogen specifically, there should

**FIGURE 1.8. Overview of factors for identifying potential trading partners of hydrogen and its derivatives**




Note: The economic trade-off has been simplified to production and transport for illustration purposes, but it also considers a wide range of factors (see Figure 3.1). CAPEX = capital expenditure; GHG = greenhouse gas; OPEX = operational expenditure; R&D = research and development.

be incentives for market creation – these could be in the form of quotas across different end uses, public procurement, or capacity targets (*e.g.* for electrolysis) – to overcome the barrier of current limited trading, since most of the hydrogen produced has long-term contracts, hindering competition and cost decrease. There should also be incentives to overcome the higher production and transport costs of hydrogen compared with fossil fuels. These could be in the form of grants, fiscal support, premiums, or carbon contracts for difference (CCfD). An incentive could also be the government acting as guarantor, giving long-term certainty on revenues and reducing the project risk (see Box 1.3). There should be a clear regulation of infrastructure, including uniform gas quality standards, clear tariff structure, third-party access, unbundling of the market, financing mechanisms, and free and fair competition among suppliers (Gas for Climate, 2021a). Lastly, permitting and approval processes should be simple so as to facilitate project execution and avoid delays. Aspects to include here would be the cost of the administrative process, and its duration, complexity and integration with the existing process for renewable power.

**Geopolitical factors.** Hydrogen could upend the current energy landscape and transform the role of specific countries. Small energy markets with limited fossil fuel reserves could become large energy and commodity exporters by using renewable resource endowments. Hydrogen provides an opportunity for current oil and gas exporters to diversify the economy away from these resources. Most of these countries have vast renewable resources, which combined with their established industry, skilled workforce and enabling conditions for attracting foreign capital could provide the foundations for the emergence of the hydrogen industry. On the flip side, energy importers (those who are likely remain so in the future) could use hydrogen to diversify the energy mix and gain access to a different set of countries with different risks, prices and profiles. This would mean not only new relationships formed between countries but also emerging exporters, leading to a more diversified and competitive energy market.

**Political factors.** Political considerations include the existence of a stable government with clear long-term goals both for decarbonisation and specifically for hydrogen, improving project bankability; a clear governance structure; no corruption; and high transparency. Hydrogen diplomacy will also become a standard feature of economic diplomacy. The future trade partners for each country are still unclear, and countries are establishing multiple diplomatic relationships to be prepared for a wide range of future developments and market evolution. Germany, Japan and the Netherlands have been trailblazers on the importing side, but other countries are following close behind. Potential exporters are also following a similar approach, with Australia and Chile leading the way and Western Australia having a dedicated hydrogen industry minister.

**Technical factors.** Considerations relating to technology include the availability of human capital and experience with similar technologies and projects. Relevant experience encompasses project execution as well as research and knowledge production. Measures to quantify some of these soft factors include the research and development (R&D) budget for hydrogen and fuel cells as well as the number of projects, patents and publications. Another aspect is the development of the supply chain and the share of industrial activity that would be located domestically. For instance, for electrolysers, a country could put different incentives in place to implement various parts of the supply chain domestically. An option is to import the manufactured electrolysers, presumably for the benefit of lower cost, and produce the rest of the plant domestically, including compressors, power electronics and water treatment. Alternatively, there could be domestic production of the stack (the core component of the electrolyser), reducing exposure to disruption of imports or to changes in diplomatic relationships. Electrolysers and fuel cells could lead to a new technology race for patents and manufacturing. Europe and Japan are leaders across the entire hydrogen value chain in patents, and China is leading the way in electrolyser manufacturing, which is expected to accelerate in the coming years (BNEF, 2022). Another factor is knowledge and experience with multiple hydrogen carriers. Some countries might develop a preference for one of the carriers over time, leading to more projects being developed, more cumulative knowledge and a pathway dependence. If this preferred carrier is a mismatch between the importer and exporter, it could hinder trade, since facilities for one carrier could not be used for others.

**Trading dependence.** Most countries will try to avoid relying on a small number of countries as trading partners (as buyers for exporting countries and suppliers for importing ones) for reasons of energy security. Trading dependence can be measured by the number of countries and the market share of the largest partners; the same indicators used for oil and gas could be applied to hydrogen. Using a combination of indicators that cover various dimensions is usually a more robust approach. Common indicators tend to focus on the diversity of the energy mix or the energy intensity of the economy (Ang, Choong and Ng, 2015). While the distance between trading partners is reflected in the transport cost, the specific route that ships will follow and the routes' potential exposure to disruption or to use as an instrument for political influence is not captured (*e.g.* the Suez Crisis, when the canal was nationalised in 1956, or more recently, the blocking of the canal for almost a week by the grounding of a containership in March 2021). These factors might favour, for instance, a trading partner with almost the same distance and similar total cost but that would not have ships passing a maritime chokepoint. This will also depend on the time horizon being considered since this directly affects market development and flexibility. At an initial stage, with limited global trade, there will not be any spot trading or possibility to reroute ships in response to prices and demand. However, as the market develops, there will be more ships, more suppliers and buyers, giving more flexibility to optimise trade on short notice.

**Box 1.3. Double auction model for global hydrogen production for use in German industry**

Germany issued its National Hydrogen Strategy in June 2020. It consists of 38 measures across eight areas, with a ramp-up phase until 2023 and market consolidation from 2024. The strategy is supported by USD 8.4 billion (EUR 7 billion) for market rollout and USD 2.4 billion (EUR 2 billion) for fostering international partnerships (Government of Germany, 2020).

The industrial sector is one of the eight areas covered, and two key challenges are the high cost for the hydrogen pathways and the lack of policies that promote fuel shifts as opposed to marginal improvements through energy efficiency (IRENA, 2022e). The H2Global funding programme was established to tackle these barriers in the ramp-up phase. The programme uses an auction-based mechanism for both hydrogen supply and demand, aiming to match the suppliers that are able to provide the lowest cost with the users that are willing to pay the most. An intermediary body, the Hydrogen Intermediary Network, concludes the long-term contracts and pays for the gap between the purchase and sale agreements. The programme has funding of USD 1080 million (EUR 900 million) (Government of Germany, 2021). The minimum project size for application is 100 MW of electrolysis capacity. The programme was conceptualised during 2020, and the first (global) auctions will take place at the end of 2022 and will be targeted to ammonia, methanol and synthetic fuels. As technologies develop, it is expected that the gap between auctions will close, reducing the overall subsidy required.

# 2

# REGIONAL OUTLOOK FOR HYDROGEN DEMAND AND TRADE OF COMMODITIES

# REGIONAL OUTLOOK FOR HYDROGEN DEMAND AND TRADE OF COMMODITIES

## Highlights

Hydrogen demand in end-use sectors is expected to grow by almost five times by 2050 in a 1.5°C scenario. Although there is a wide range of users for this demand, chemicals and transport will be the leading sectors. Ammonia and methanol demand could grow three to four times, driven by growth in developing economies and in their use as fuels, which is currently negligible. For transport, uses as pure hydrogen to complement electricity arise in the road and rail transport sectors: use of ammonia for international shipping and synthetic fuels for international aviation are among the largest uses. For steel, demand remains uncertain given that the leading decarbonising technologies (direct reduced iron with hydrogen and carbon capture and storage) are still to be proven and rolled out at large scale.

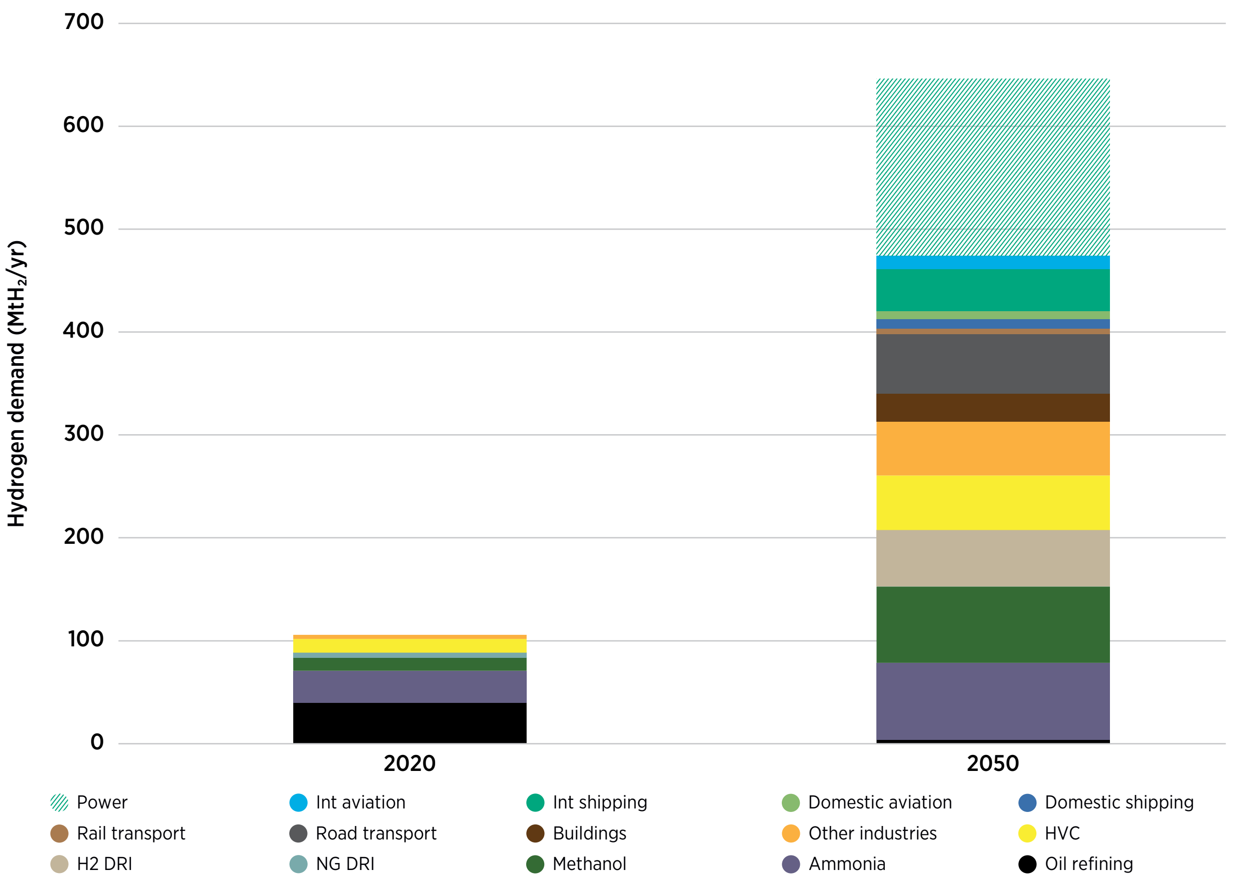
In this 2050 future, China is responsible for about a quarter of the global hydrogen demand, driven by the industrial sector. A distant second, with almost a third of China's demand, is India, where the demand is driven by steel production, which could quadruple by 2050. The country with the third largest demand is the United States of America, going from about 10 $MtH_2$/year today to over 30 $MtH_2$/year in 2050, with most of the growth driven by the transport sector. Hydrogen demand by 2050, in this 1.5°C scenario, is expected to be relatively concentrated, with the top ten countries in the world representing about two-thirds of the global consumption.

The opportunity to trade commodities instead of hydrogen is large, given the concentration of the demand. Today, for ammonia (as feedstock), methanol, steel and international shipping, the top ten countries in demand consume between 75% and 90% of the global demand. This means that establishing commodity trading routes with relatively few countries would cover a large part of the global demand.

In a 1.5°C scenario, hydrogen can complement electricity and satisfy the energy demand of sectors that are difficult to electrify. Thus, hydrogen has the largest added value for heavy industry and long-haul transport. At the global level, the 2050 hydrogen demand is expected to be 614 $MtH_2$/year (74 exajoules [EJ] per year) (IRENA, 2022a). This section depicts the regional and sectoral outlook for hydrogen demand in 2050.

Pure hydrogen production grows by a factor of more than six from 2020 to 2050 (see Figure 2.1). Today, hydrogen is mostly used for industrial purposes, namely oil refining, chemicals, and steel production. Of these, oil refining could experience the largest decrease due to a shift towards synthetic fuels and biofuels. Ammonia and methanol demand are expected to grow three to four times, driven by growth in developing economies and use as fuels (especially for ammonia in the shipping sector). In steel, hydrogen can be a reducing agent for producing iron. Currently, about 7% of primary steel production uses this route, although using natural gas as the energy source. In the future, this could change towards pure hydrogen being used to produce reduced iron. Towards 2050, the largest area of growth will be the transport sector. Uses for pure hydrogen to complement electricity arise in the road and rail sectors, in which use of ammonia for international shipping and synthetic fuels for international aviation are among the largest uses. The rest of the demand for 614 $MtH_2$/year would come from the power sector to meet the need for flexibility and thermal generation to compensate for fluctuations in variable renewable energy and complement other flexibility measures. The hydrogen consumption for the power sector (as seasonal storage) will be updated by IRENA in future modelling exercises, coming from integrated gas and power modelling. Thus, for this report, the share of consumption for power has been excluded.

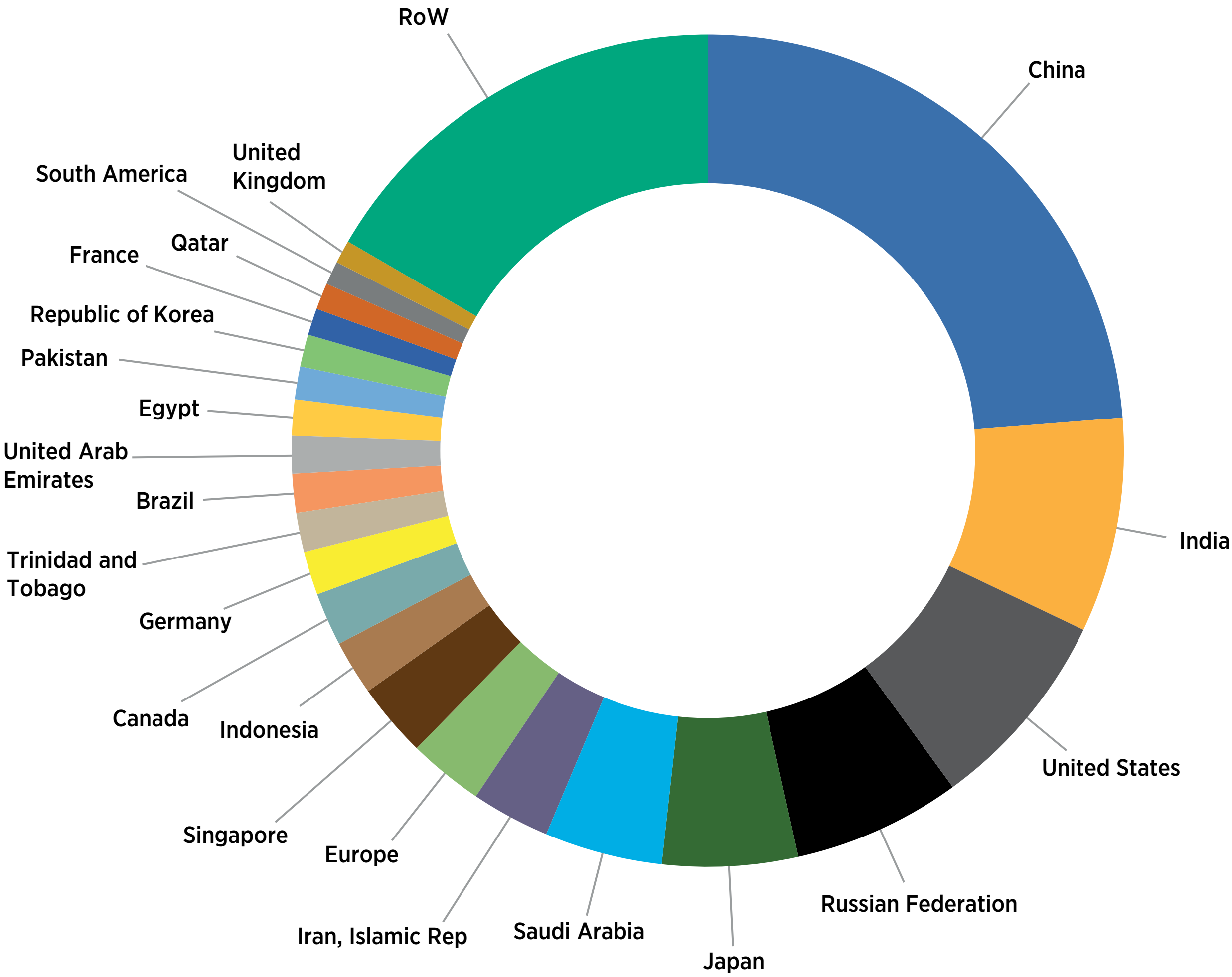
**FIGURE 2.1. Hydrogen demand by application in 2020 and 2050**




Note: Hydrogen demand for 2020 excludes hydrogen as part of the mix of off-gases for steel production. DRI = direct reduced iron; HVC = high-value chemicals; Int = international; NG = natural gas.

China is today the largest hydrogen consumer in the world, at about 24 $MtH_2$/year in 2020 (IEA, 2021b). It produces about a quarter of the global hydrogen used for refining and is home to about a quarter of the global ammonia production and over half the global methanol and steel production. By 2050, in a 1.5°C scenario, China is expected to remain a leading industrial country, and even considering the new hydrogen applications, China could retain about a quarter of the global hydrogen demand, driven by the industrial sector (70% of its demand). A distant second, with almost a third of China's demand would be India. India's steel production is expected to quadruple by 2050, which combined with one of the largest iron ore reserves in the world and low-cost renewable electricity opens up the opportunity to use electrolytic hydrogen for direct reduction of iron. One barrier for this potential match is the difference between the time when new steel production is needed and the time needed to develop the DRI technology, since DRI might still need 8-13 years to reach the commercial stage (Draxler *et al.*, 2021; IEA, 2021c). The country with the third largest demand would be the United States of America, going from about 10 $MtH_2$/year today to over 30 $MtH_2$/year in 2050, with most of the growth driven by the transport sector. Hydrogen demand by 2050 is expected to be relatively concentrated, with the top ten countries in the world representing about two-thirds of the global consumption (see Figure 2.2).

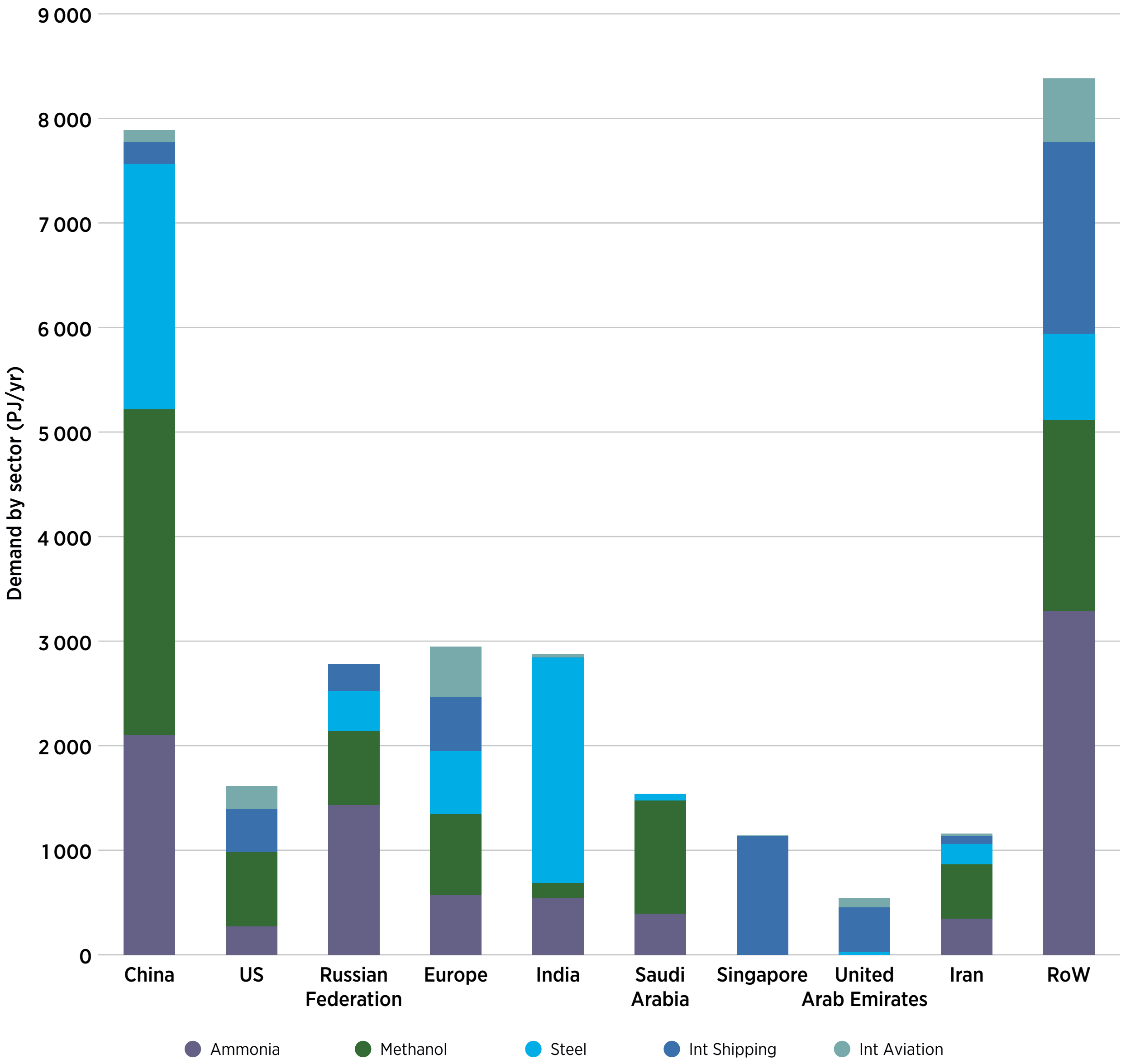
**FIGURE 2.2. Hydrogen demand by country in 2050 in a 1.5°C scenario**




Note: RoW = rest of the world.

As highlighted in Section 1.2, depending on the end use of the hydrogen, it might be more cost-effective to first transform it into a commodity and then ship the commodity instead of the hydrogen itself. This might be attractive for ammonia (both as a chemical feedstock and a fuel), methanol, steel and synthetic fuels. For the latter three, reconversion to hydrogen would not take place and the commodity would be used as transported. Figure 2.3, resulting from this analysis, shows the top nine regions in terms of demand for each of these commodities. Two of the most concentrated commodities, with almost 80% of the global demand covered by the top nine regions, are methanol and steel. At the other extreme is international aviation, which is a highly segregated market where many countries have a small share that together aggregate to almost 40% of the global demand.

**FIGURE 2.3. Top nine regions with largest demand for ammonia, methanol, steel and long-haul transport in 2050 (PJ/year)**




Note: Ammonia and methanol demand exclude share used for international shipping. Int = international; RoW = rest of the world.
Source: This analysis

The production of commodities other than pure hydrogen will depend not only on the cost differential considering production and transport costs (see Box 2.1) but also on factors like maturity of the industry, availability of domestic labour, knowledge of specific technologies, industrial policy, trade policies, targets for greenhouse gas (GHG) emissions mitigation, availability of renewable resources, and size of the renewable energy industry (see Section 1.4). For instance, Singapore is one of the main international hubs for shipping, and it is expected to remain so in the future. However, it has limited land availability to domestically satisfy the fuel demand for international shipping. One option is for Singapore to trade hydrogen-derived fuels with low-cost energy regions and use large domestic storage capacities to ensure security of supply. Another option is that the arise of new fuel suppliers leads to other countries in the region becoming bunkering hubs. In this case, it is a trade-off of quantitative and qualitative factors that will only be unveiled as time passes and will be largely influenced by the domestic policies adopted.

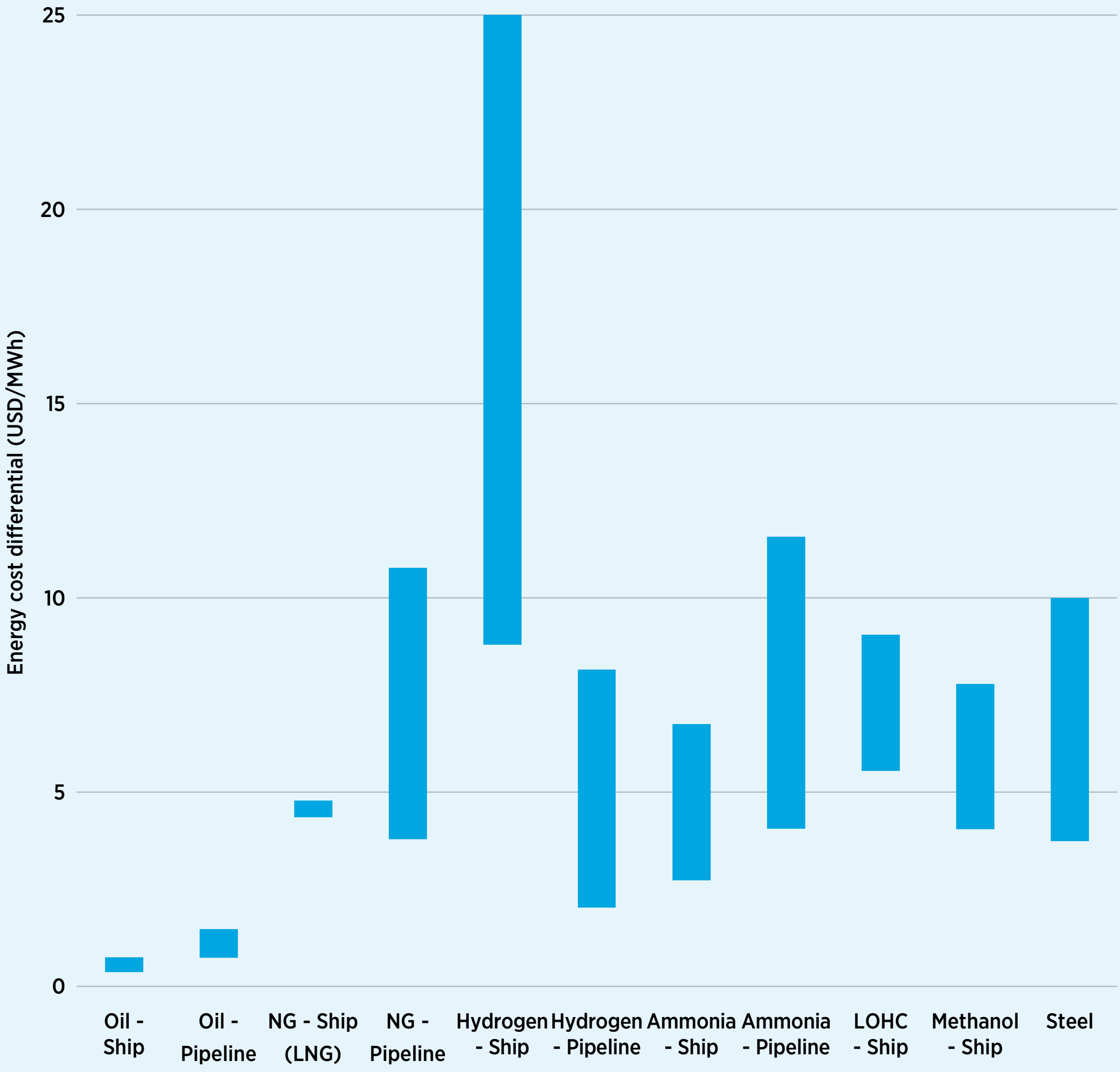
**Box 2.1. Trade of commodities and hydrogen-derived products**

Hydrogen has the advantage of being a versatile commodity that can be further converted into multiple carriers and materials. These carriers have a higher energy density, which increases transport capacity and makes transport cheaper. For example, by going from electricity to hydrogen, the transport capacity can be increased from a typical 1-2 GW to 10-20 GW (for a 122 cm pipeline). When liquid (*e.g.* synthetic oil) pipelines are considered, the transport capacity increases even further, to 80-100 GW (for a 122 cm pipeline). Thus, the choice of transport carrier considers the trade-off between efficiency losses associated with further conversion steps, which will result in a higher cost, and the lower transport costs and higher capacity that will be achieved by using the derived carrier.

Figure 2.4 shows the energy cost differential between two regions that would be required to justify the relocation of the production of various commodities. This analysis considers the energy losses that occur as the commodities are transformed. For example, oil is relatively cheap to transport in tankers, at USD 1.2-2.4/bbl for every 10 000 km (Saadi, Lewis and McFarland, 2018), which translates to about USD 0.7-1.4/MWh. But efficiency losses from electricity to synthetic fuel are roughly 50%* (Albrecht *et al.*, 2017; Ikäheimo *et al.*, 2019). This means that any difference in the electricity price between regions will only be accentuated (in this case by a factor of two or three) with the transformation process. That means electricity price differentials of USD 0.35-0.70/MWh would already be enough to justify the relocation of synthetic oil production. This difference is very small since oil tankers are one of the most cost-effective ways to transport energy (*i.e.* high energy density of the carrier combined with the mode of transport with the highest efficiency); however, the difference can go up to USD 25/MWh when considering liquid hydrogen ships, and it is between USD 5/MWh and USD 10/MWh for transport across 10 000 km for most commodities (Figure 2.4). The comparison does not need to include capital cost for the equipment since that would not be a differentiator between the importing and exporting region (*e.g.* an ammonia synthesis plant would be needed in both locations if the final product is ammonia and without considering location cost factors).

**Box 2.1 (Continued)**

**FIGURE 2.4. Energy price differential to justify production relocation**




Note: Transport costs are for 10 000 km. Numbers do not include reconversion to hydrogen and assume that the commodities can be used directly. The figure only compares pathway efficiencies with transport cost. For steel, electricity is assumed to be used for electrolysis followed by direct reduction of iron. LNG = liquefied natural gas; LOHC = liquid organic hydrogen carrier; NG = natural gas.
Sources: Al-Breiki and Bicer (2020); Goff (2020); IRENA (2022b); Saadi, Lewis and McFarland (2018); Steuer (2019).

Liquid hydrogen is the most expensive form to transport (per MWh-km) across options, and oil is the cheapest. Iron is also relatively cheap to transport, which makes the case for producing reduced iron in places with good renewable resources and exporting it to other countries for further treatment (*e.g.* casting, rolling) (Gielen *et al.*, 2020). This could be the case in Australia, China and India, which have large iron ore reserves and good renewable resources. Australia today is an exporter of iron ore rather than iron or steel. Transporting natural gas is less expensive than transporting liquid hydrogen, followed by liquid organic hydrogen carriers, methanol, ammonia, and hydrogen pipelines.

**Box 2.1 (Continued)**

The other factor to consider is how these transport costs compare with the production cost differential for the same fuel or commodity between regions. For this, the efficiency of converting from renewable energy to the commodity needs to be considered. For most of the pathways in Figure 2.4 (except hydrogen pipelines), such efficiency is 50-60%. Considering these efficiencies, a difference of USD 10/MWh in the electricity price between two regions could result in over ten times the typical transport cost for oil in ships, almost double the typical cost of liquefied natural gas transport, and still more than the typical transport cost of ammonia and steel. Thus, such a differential would justify the import of most commodities for direct use (not as hydrogen carriers) over 10 000 km. To put a USD 10/MWh differential into perspective, this would have the same impact as a weighted average cost of capital difference of two percentage points between two regions, a difference of USD 140-200/kW of capital expenditure for renewable power generation, or a difference of four to seven percentage points in capacity factor. Thus, not much is needed to be able to justify trade of commodities, since the transport costs are low compared with energy cost differentials (Figure 2.4).

Industry relocation may have a significant impact on the energy and $CO_2$ balance of countries due to the magnitude of industrial operations. Densely populated countries with high energy consumption intensity, for example in East Asia and Western Europe, can be particularly affected. Industry relocation for energy reasons is not unheard of: following the oil crises in the 1970s, Japan phased out primary aluminium smelters and switched to imports; another example is the industrial relocation to China after its accelerated economic growth beginning in the early 2000s. To make this relocation possible, carbon border adjustment mechanisms will be essential and must be internationally harmonised, accounting for all the relevant emissions. Discussions on carbon accounting for green commodities should be linked with clean energy generation (Gielen, 2021).

From the 50 EJ/year of hydrogen demand in 2050 (excluding the power sector), about 3.3 EJ/year are for domestic and international aviation. This hydrogen is combined with $CO_2$ from biogas or air (through direct air capture) to produce synthetic fuels. Given that oil transport is comparatively low cost (see Figure 2.4) and that direct air capture does not have geographical constraints (as biomass does), it is expected that most of these synthetic fuels will be produced in places that have low-cost renewables and exported to demand centres. Since it is relatively cheap to ship synthetic fuels around, cost is not expected to be the driver of trading pairs and the cost penalty for changing suppliers is expected to be relatively small. Future IRENA analysis will look in more detail at the trade of commodities.

Signs are emerging of an increase in locating industry closer to cheaper renewable resources. Green ammonia (produced from green hydrogen) is becoming economically feasible. Announced projects for renewable ammonia currently add up to 34.1 Mt/year by 2030. This is almost 19% of the current global ammonia production. Approximately 30 commercial-scale plants are in development, mainly in places with very low-cost wind and solar potential such as in remote parts of Australia, Chile, Egypt, Oman, United Arab Emirates and Saudi Arabia. IRENA and the Ammonia Energy Association are jointly assessing the opportunities for green ammonia in more detail (IRENA & AEA, 2022).

* Energy losses can increase to about 65% if $CO_2$ from direct air capture is considered.

# 3

# GLOBAL HYDROGEN TRADE OUTLOOK

# GLOBAL HYDROGEN TRADE OUTLOOK

## Highlights

Based on our techno-economic optimisation model, by 2050, in a 1.5°C scenario, about a quarter of the global hydrogen demand (18.4 EJ/year) is expected to be internationally traded. Of this, around 55% is expected to flow as pure hydrogen in pipelines, mostly retrofitted natural gas pipelines, concentrated in two regional markets: Europe (85%) and Latin America. The remaining 45% of the internationally traded hydrogen is expected to be shipped, mostly as ammonia to be used without reconversion to hydrogen. Europe can take advantage of the existing natural gas infrastructure to build a hydrogen transmission network. North Africa is one of the key partners for trade through pipelines. Italy and Spain can play a hub role between the large hydrogen production in North Africa and the rest of Europe, also leveraging North Africa's excellent renewable potential to produce green hydrogen for both domestic consumption and trade. Globally, Australia, Chile and North Africa have the largest hydrogen trade balance surplus, while Germany, Japan, the Republic of Korea and other European countries are among the largest net importers. The share of hydrogen traded by 2050 is larger than today's natural gas trade (33%) and much smaller than oil (74%). In terms of net energy flows, the 18.4 EJ/year of the hydrogen trade would still be much smaller than the global natural gas trade of about 44.8 EJ in 2020 (with an almost equal split between pipelines and liquefied natural gas).

Ammonia is the most attractive shipping pathway due to its relatively low transport cost. This means that small production cost differentials between regions would make trade attractive. By 2050, about 690 Mt/year of ammonia are needed in a 1.5°C scenario. Almost 80% of this (560 $MtNH_3$/year) is for use as chemical feedstock and fuel for shipping, and only the remaining 20% is for use as hydrogen carrier. From the 570 Mt/year of total green ammonia supply, about two thirds are globally traded. The main ammonia exporters are Australia, India, North Africa and the United States of America. Brazil, Canada, China and Latin America are largely self-sufficient regions. The largest net importers are Germany, Indonesia, Italy, Japan, Southeast Asia and the rest of Asia. Some parts of the Middle East are also net importers, mainly driven by a high cost of capital that makes domestic production more expensive than importing from countries with very low green ammonia production costs. However, the cost of financing renewable energy projects in the Middle East and North Africa region already varies significantly from country to country: future analysis will further highlight countries in the region with strong potential and enabling conditions for green hydrogen, in addition to Saudi Arabia, which are analysed separately in this report. For example, the United Arab Emirates has a target of reaching 25% global market share by 2030 and is already taking ambitious steps in this direction. For most regions, supply is relatively diversified among various countries, with a relatively close delivered cost. This highlights the benefit of renewable energy, which is ubiquitous, with many countries being able to produce low-cost electricity and green hydrogen, which is not the case for fossil fuels. It also highlights the importance of de-risking investments in renewables and electrolysis, as regions with excellent renewable resources but a high cost of capital can be less competitive than regions with worse renewable resources but cheaper financing.

To achieve this future, a total investment of USD 4 trillion is needed across the entire green hydrogen value chain (from generation to reconversion plants, including the share that is not traded) to deploy 10.3 TW of renewable capacity, 4.4 TW of electrolysis and 1.6 TWh of batteries.

The cost of green hydrogen production is projected to drop from around USD 5/kg$H_2$ today to below USD 1/kg$H_2$ (coupled with solar photovoltaic) for most regions in 2050. Ammonia shipping costs are projected to decline by one order of magnitude, from USD 8/kg$H_2$ to USD 0.8/kg$H_2$. At these price levels (USD 1.5-2/kg$H_2$ for delivered hydrogen), the green hydrogen supply cost would equal the liquefied natural gas supply cost of 2020. Innovation, mass manufacturing and global supply chains are needed for these cost reductions to materialise. This analysis also assumes that a market will develop for clean hydrogen. As of 2022, this market is still nascent, with less than 1 GW of electrolyser capacity in place worldwide, four orders of magnitude below the 4 400 GW needed by 2050.

These results are based on a greenfield approach, which means that legacy assets other than natural gas pipelines are not considered, focusing instead on dedicated wind and solar facilities to power electrolysis and conversion plants (*e.g.* ammonia production and hydrogen liquefaction plants), and optimistic assumptions regarding cost reductions along the supply chain are used. The overall share of trade is relatively robust for a different set of assumptions, but it can change up to 30% depending on the scenario. The most critical parameters are transport and generation cost. Doubling the transport cost can reduce global trade by a third and has the largest impact on hydrogen trade rather than ammonia trade. Increasing generation costs by 20% can result in about 10% higher trade.

The outlook for specific countries can change significantly for different scenarios. Australia and Chile could see their exports reduced if their cost of capital advantages compared with some of the countries with large demand disappear over time or if reductions in transport costs are lower than expected. Thus, this degree of hydrogen trade will be subject to the global willingness to implement a 1.5°C pathway, recognise the value of green hydrogen in reducing carbon emissions and consequently scale up investments in all parts of the supply chain, from solar and wind to electrolysis, new hydrogen pipelines, retrofitted natural gas pipelines and ammonia shipping infrastructure. Innovation will also be crucial to bringing down the cost of green hydrogen and hydrogen trade infrastructure.

Most countries have several alternatives for trade with a very similar cost profile, which means trade pairs will most likely be defined by factors beyond cost (IRENA, 2022d). For instance, there are already multiple pipelines connecting North Africa to Europe, which are used today to import natural gas. If converted to carry 100% hydrogen, these would have more than enough capacity to satisfy the European Union 2030 targets and provide a low-cost transport option in the most critical phase for development, replacing natural gas revenues with hydrogen and keeping in place existing trade relationships, as well as infrastructure.

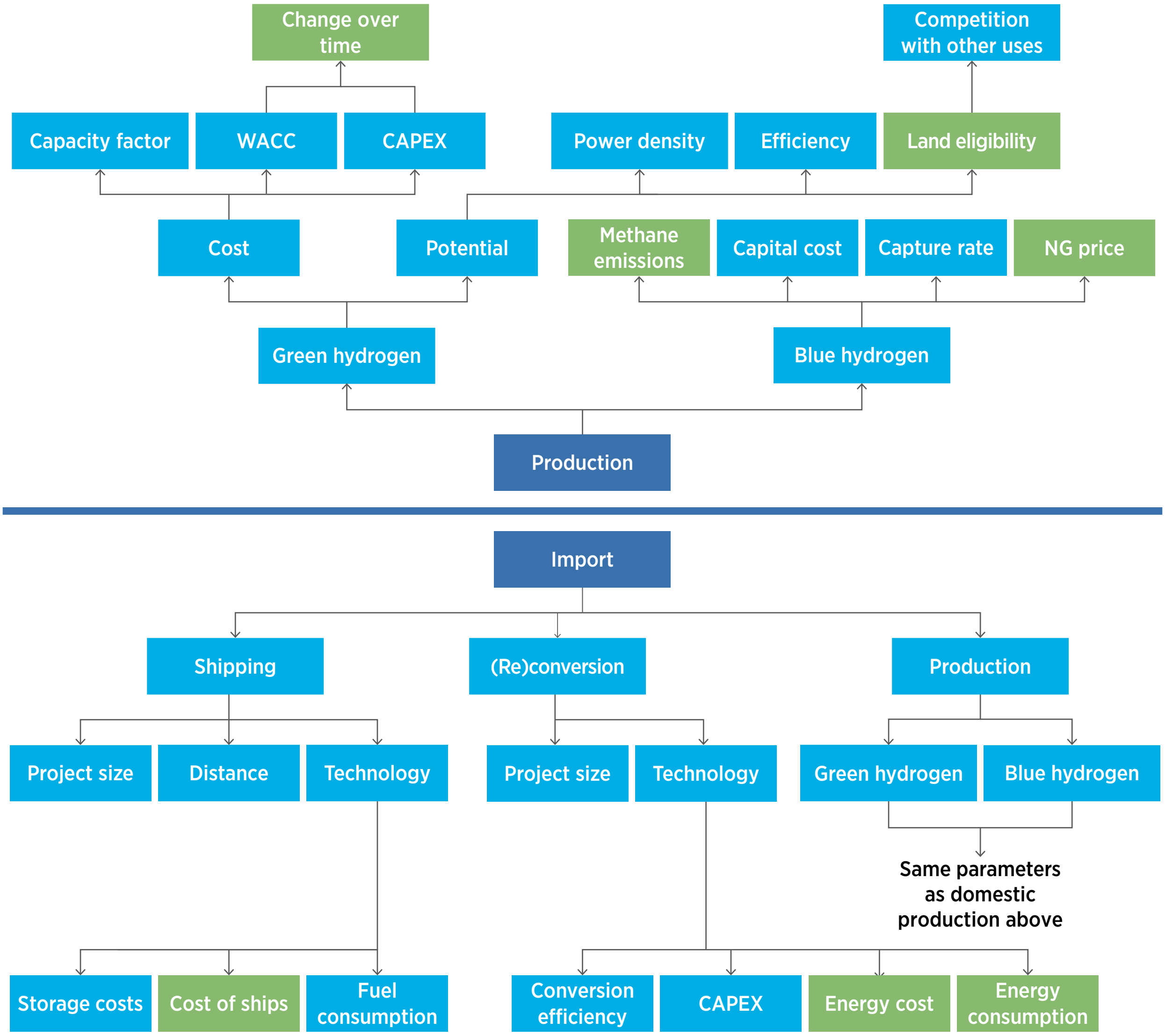
The limited cost differentials introduce a large degree of uncertainty for future flows. Given the current technology status, trade volumes will most likely remain limited for the coming decade, with commodities, especially ammonia, becoming the most feasible candidates for trade in the short term. In addition to ammonia, other commodities that use green hydrogen, like green iron, green methanol and green synthetic fuels might also be traded instead of pure hydrogen. These will be the subject of further IRENA analysis.

## 3.1 Main drivers of global trade

The potential opportunities for global trade are driven in part by the cost differential over time between domestic production and imports. Each of these components can be further broken down into their fundamental drivers (see Figure 3.1). Two of the key drivers are how the CAPEX and weighted average cost of capital (WACC) evolve over time. Today, there is quite a spread for these two parameters across countries. The WACC for utility-scale solar PV ranges from less than 4% in Australia, Germany and the Netherlands to more than 12% for Argentina, Ecuador, the Islamic Republic of Iran and Ukraine. This difference alone could nearly double the electricity cost (see Figure 3.2). At the same time, aspects like local labour cost, installation cost and scale of domestic industry can lead to an equally wide spread for the CAPEX. By the end of 2020, places like Southeast Asia or Norway could achieve costs below USD 600 per kilowatt (kW) for solar PV, while Japan or the Russian Federation could be above USD 1800/kW (IRENA, 2021b). The dynamics for global trade will be greatly affected by how these differentials across regions evolve over time (Bogdanov, Child and Breyer, 2019; Egli, Steffen and Schmidt, 2019). The reference case for this study explores a future where technology risks, driving part of the WACC difference across regions, disappear over time as deployment increases in all regions, while still leaving some difference in WACC based on factors beyond technology. For CAPEX, it has been assumed that values across countries will tend to converge over time due to the global nature of solar modules, inverters and wind turbines, while some differences will remain, for instance due to different installation costs driven by the level of competition and cost of labour in different markets. This means that while today the ratio between the countries with the lowest and the highest CAPEX for solar PV is about five, this ratio could be reduced to 2-2.5 towards 2050.

This analysis is based on variable renewable energy technologies: solar PV, onshore wind and offshore wind. These technologies have experienced a 55-85% decrease in costs over the last decade, and their global capacity will increase by at least an order of magnitude in a 1.5°C scenario, further driving learning effects. Other renewable technologies are excluded from the analysis. Concentrated solar power is excluded due to its high capital costs, which would lead to high hydrogen production costs. Geothermal has presented a cost increase in the last decade, and it is not as widely available around the world as solar and wind. For hydropower, the remaining potential with a low electricity price (USD 25-50/MWh) is between 1500 and 3500 TWh (Gernaat *et al.*, 2017), which would only be a small share (7-17%) of the green hydrogen supply by 2050.

**FIGURE 3.1. Economic factors to consider in the trade-off between domestic production and import of hydrogen**




Note: Boxes in green are the ones with the largest influence over the results. Differences in solar irradiation or wind velocity between regions will be reflected in the capacity factor of renewable energy. CAPEX = capital expenditure; NG = natural gas; WACC = weighted average cost of capital.

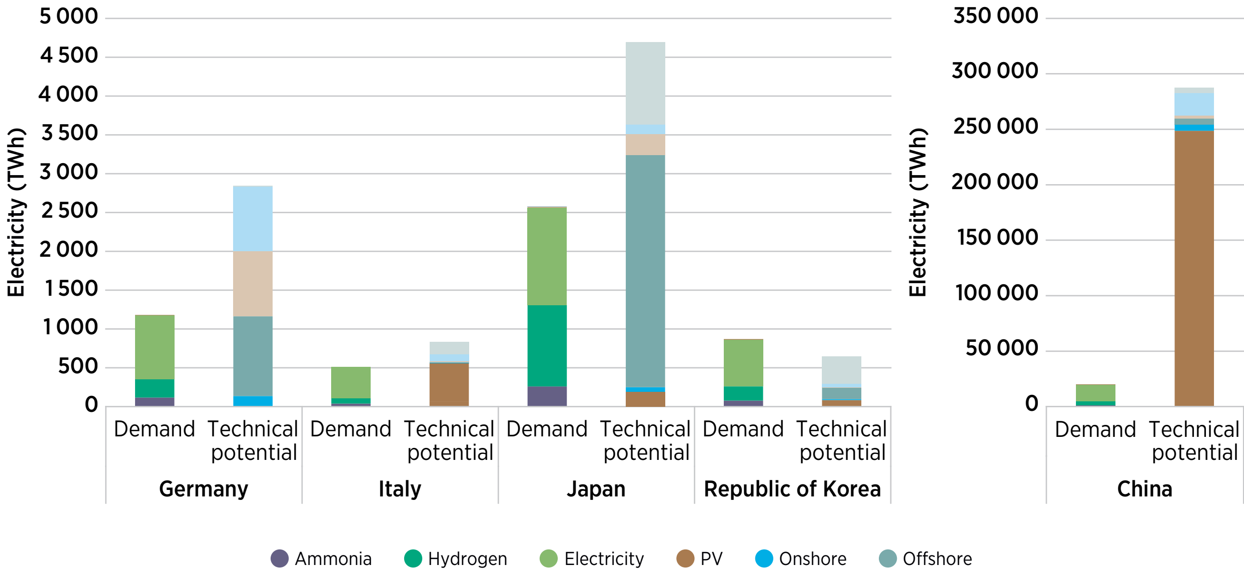
**FIGURE 3.2. Electricity price (expressed in USD/kg$H_2$ equivalent) as a function of CAPEX for renewable generation, WACC and capacity factor**

| | CAPEX (USD/kW) | | | | | CAPEX (USD/kW) | | | | | CAPEX (USD/kW) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 1000 | | | | | 500 | | | | | 250 | | | | |
| WACC/CF | 0.1 | 0.15 | 0.2 | 0.25 | 0.3 | 0.1 | 0.15 | 0.2 | 0.25 | 0.3 | 0.1 | 0.15 | 0.2 | 0.25 | 0.3 |
| 3.0% | 3.6 | 2.4 | 1.8 | 1.4 | 1.2 | 1.8 | 1.2 | 0.9 | 0.7 | 0.6 | 0.9 | 0.6 | 0.4 | 0.4 | 0.3 |
| 5.0% | 4.3 | 2.9 | 2.1 | 1.7 | 1.4 | 2.1 | 1.4 | 1.1 | 0.9 | 0.7 | 1.1 | 0.7 | 0.5 | 0.4 | 0.4 |
| 7.5% | 5.3 | 3.5 | 2.6 | 2.1 | 1.8 | 2.6 | 1.8 | 1.3 | 1.1 | 0.9 | 1.3 | 0.9 | 0.7 | 0.5 | 0.4 |
| 10.0% | 6.4 | 4.2 | 3.2 | 2.5 | 2.1 | 3.2 | 2.1 | 1.6 | 1.3 | 1.1 | 1.6 | 1.1 | 0.8 | 0.6 | 0.5 |
| 12.5% | 7.5 | 5.0 | 3.8 | 3.0 | 2.5 | 3.8 | 2.5 | 1.9 | 1.5 | 1.3 | 1.9 | 1.3 | 0.9 | 0.8 | 0.6 |

Note: Values are in USD/kg$H_2$, and an efficiency of 72% (in lower heating value) is assumed for the electrolyser. CAPEX = capital expenditure; CF = Capacity factor; NG = natural gas; WACC = weighted average cost of capital.

The other factor that defines the attractiveness of domestic production is the technical potential of renewable energy, which is fundamentally driven by land eligibility constraints (IRENA, 2022c). Aspects such as social acceptance, visual and noise issues for wind turbines, effect on bird migration, and land cost escalation with higher utilisation have not been considered in this study. Some countries might have limited potential overall or just enough to cover their domestic electricity demand, which will also grow significantly due to electrification of transport and residential demand. In most countries, the renewable potential is multiple times (in many countries more than 100 times) the potential electricity demand. However, for some countries this potential is either not enough to fully cover electricity demand or only enough if low-quality resources are included, which would lead to comparatively high electricity cost due to low generation per unit of capacity (see Figure 3.3).

**FIGURE 3.3. Electricity, hydrogen and ammonia demand in 2050 in comparison with the technical renewable potential for solar PV, onshore wind and offshore wind in selected countries**



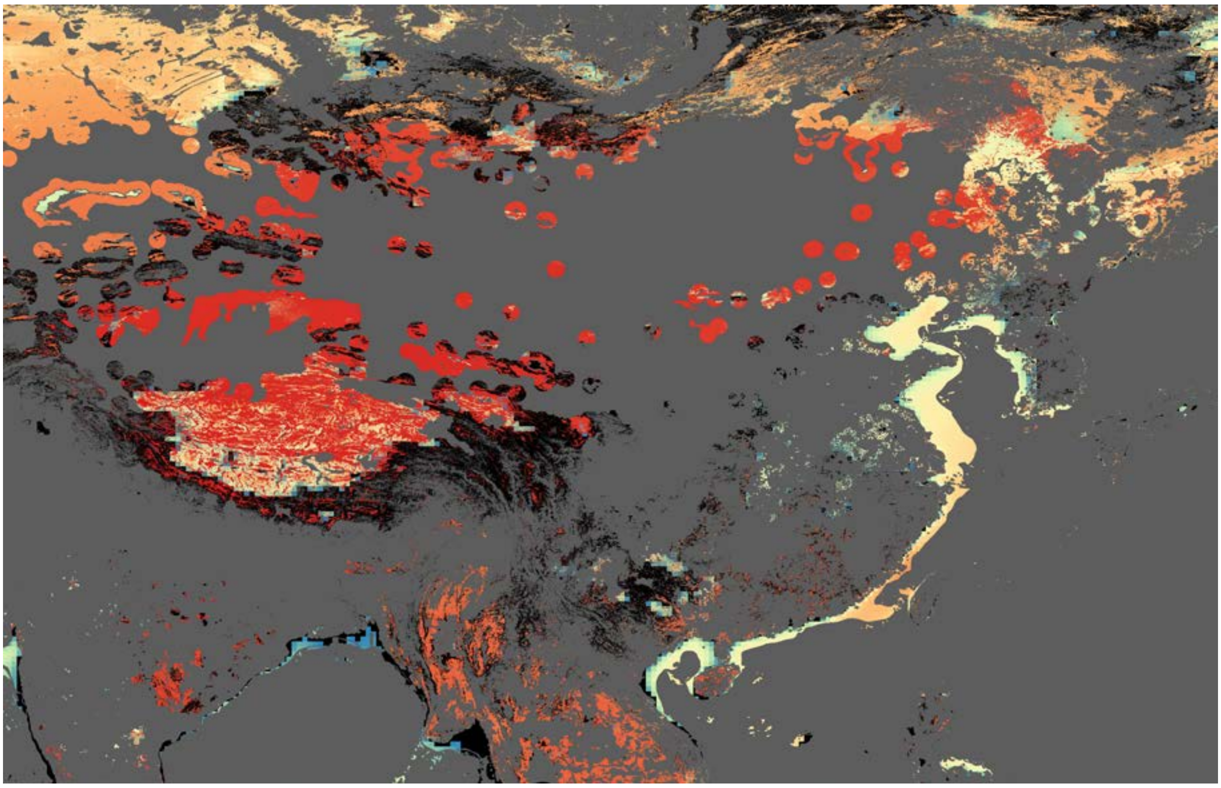

Note: Ammonia and hydrogen demand (see Chapter 2) have been converted to electricity demand. Electricity demand comes from the *World Energy Transitions Outlook* 1.5°C scenario (IRENA, 2021d). *On* refers to onshore wind. *Off* refers to offshore wind. CL refers to *Class* to denote the quality of the resource. PV-CL1 covers all the photovoltaic (PV) resources with a capacity factor of >20%, CL2: 17-20%, CL3: 14-17%, CL4: 11-14%. For onshore and offshore wind, CL1: >60%, CL2: 45-60%, CL3: 30-45%, CL4: 15-30%. Shaded area denotes renewable resources with the lowest capacity factors from CL4. Technical potential considers protected areas, forests, wetlands, urban centres, slope and water stress but not social acceptance or increase in land costs when a higher share of land is used. For more detail on the technical potential, refer to Part III of this report series (IRENA, 2022c).

For Germany, about 30% of the total renewable technical potential is PV. The combined onshore wind and solar potential is more than 67% higher than the 2050 demand (including domestic production of hydrogen and ammonia). Therefore, in theory, the country could satisfy all its demand with domestic supply (see Figure 3.3). However, all the PV potential is relatively poor quality, with an annual average capacity factor of 11-14%, which makes the generated electricity more expensive (USD 18/MWh) than other countries with better solar resource quality. Similarly, the offshore wind technical potential of 1 000 TWh is an upper bound. This does not consider that as wind farms are installed, the effective full-load hours of the subsequent farms are reduced. This can happen already for relatively small capacities of 50-70 GW of offshore wind that various scenarios estimate for 2050 (Agora Energiewende, 2020). At the same time, Germany (like Italy) has an existing gas infrastructure interconnected with the rest of Europe, which could be repurposed to hydrogen. This decreases the transport cost, especially for large volumes, to less than USD 0.1 per kilogramme of hydrogen ($kgH_2$), making imports attractive.

Japan and the Republic of Korea are more constrained than Germany. First, the largest share of the renewable technical potential (84% and 70% for Japan and the Republic of Korea, respectively) is from offshore wind, which has on average higher electricity prices due to the higher CAPEX (compared with onshore wind or PV). This results in more expensive hydrogen production despite the higher number of operating hours. Second, when only the onshore wind and PV potentials are considered, these would only cover 33% and 25% of the entire electricity demand (including ammonia and hydrogen production) (see Figure 3.3). Third, for both countries, most of the renewable potential is of poor quality, especially for onshore wind, which has a capacity factor of less than 30%. This leads to an electricity price of USD 40-45/MWh, which would already be equivalent to USD 2.2/kg without considering the electrolyser cost. Fourth, neither of the two countries has pipelines for cross-border trade today due to the cost, leaving shipping as the only potential pathway for energy trade.

China has an onshore wind and PV technical potential 15 times larger than the future electricity demand of a 1.5°C scenario by 2050. However, there is a large mismatch between supply and demand centres. Virtually all the renewable potential is in Inner Mongolia, Qinghai, Tibet and Xinjiang (see Figure 3.4); three of these provinces are the country's least populated and only have 3% of the country population.

**FIGURE 3.4. Levelised cost of green hydrogen map for China in 2050 for an *optimistic* cost scenario with water stress considerations**




Note: Optimistic capital expenditure assumptions for 2050: photovoltaic (PV): USD 225-455/kW; onshore wind: USD 700-1070/kW; offshore wind: USD 1275-1745/kW. Electrolyser: USD 130/kW. Weighted average cost of capital as per 2020 values without technology risks across regions. Green hydrogen potential is based on assessing land availability for solar PV and wind.

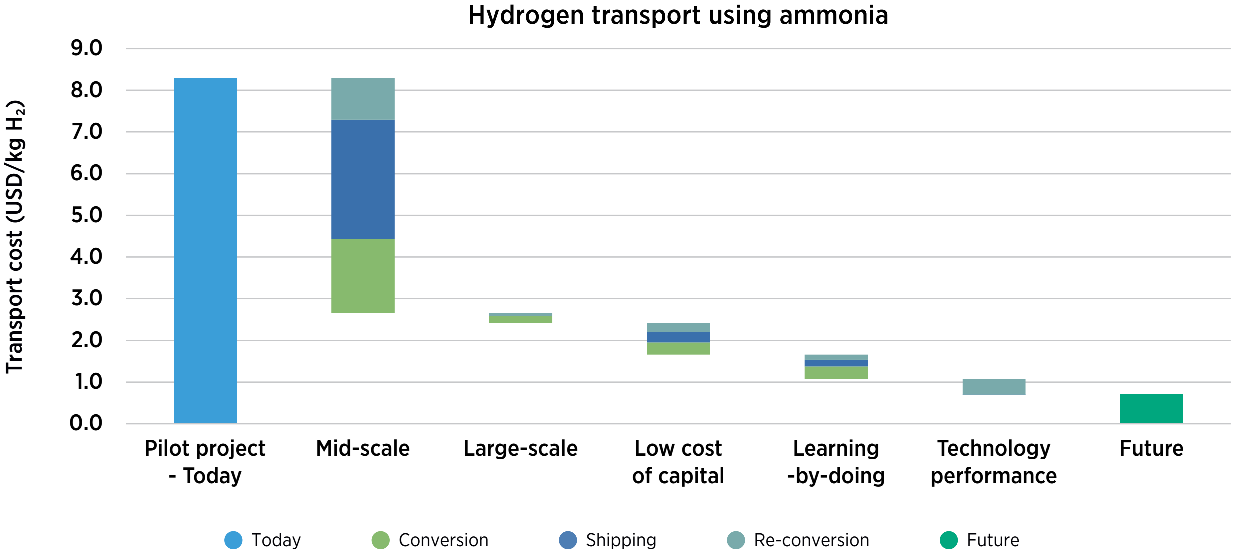
Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

Most of the population is in the southeast, where most of the land is not available for renewable energy due to forest land cover, croplands, grasslands or urban areas. Existing natural gas infrastructure is also in the southeast, and there are no pipelines from the areas with high renewable potential that could reduce the cost of transport. Thus, China either needs to build new infrastructure to take advantage of these sites or new infrastructure to import hydrogen. As an example, a 122 centimetre (cm) pipeline (largest common diameter) from Qinghai to Shanghai (about 2 500 km of linear distance) would require an investment of almost USD 10 billion.[10] Such a pipeline would have an equivalent capacity of about 13 GW, while the average hydrogen demand for China is expected to be about 380 GW in a 1.5°C scenario. Another option is to tap into the renewable potential in the west of the country; hydrogen could be converted on-site into the form in which energy is ultimately needed (*e.g.* ammonia, methanol, steel), reducing the investment needs and increasing the transport capacity.

For India, the land available for PV is largely limited by cropland (USGS, n.d. a). The country also has an increasingly large population and industrial growth driving demand. This makes the total electricity demand (including hydrogen and ammonia) reach almost 8 000 TWh by 2050, while the PV potential is about 16 000 TWh. The quality of this resource is excellent (more than half has a capacity factor greater than 20%), which leads to prospects for India to be an exporter.

The potential for trade is defined once domestic production is compared with the potential import. For the import, two additional parameters to be considered are the shipping and (re-) conversion costs. These costs will depend on the technology choice and the point in time (*i.e.* technology development). Figure 3.5 shows the transport cost from these three components (conversion, shipping, reconversion) for ammonia, with the other two carriers (liquid organic hydrogen carrier [LOHC] and liquid hydrogen) following a similar trend.

**FIGURE 3.5. Factors contributing to the reduction of ammonia transport cost**




Note: Pilot project scale: 10 kt$H_2$/year; mid-scale: 200 kt$H_2$/year; large scale: 1.5 Mt$H_2$/year. Cost of capital is assumed to change from 15% today to 5% in the future. Learning-by-doing is considered through a cost ratio between a first-of-a-kind and an *n*th-of-a-kind plant. Technology performance is mainly considered through reduction in energy consumption. Figure only covers costs for transport, (re)conversion, storage and terminal; it excludes production costs.
Source: IRENA (2022b).

[10] *Using Western cost standards, which will potentially be lower in China due to lower labour costs and faster project execution.*

Today, transport costs for hydrogen via ships range between USD 6.5/kg and USD 17.3/kg[11] (IRENA, 2022b). The main factor determining the high costs is the project scale. Pilot projects are not able to reach commercial size for any component of the value chain, leading to much higher specific costs. Among the three carriers considered (liquid hydrogen, LOHC and ammonia), this has the highest impact on liquid hydrogen, which requires cryogenic conditions, resulting in high capital cost. The ships and the liquefaction plant represent most of the cost in a small-scale liquid hydrogen value chain. When the scale increases to 100 kilotonnes of hydrogen ($ktH_2$) per year, the cost is already reduced by 75% (IRENA, 2022b). This scale is still not enough to achieve the commercial scale for all the steps in the value chain, but it is enough to go beyond the scale where the cost penalties are prohibitive. A 100 $ktH_2$/year liquefaction facility is sufficient to process the output of an electrolyser of about 750 MW operating at 50% capacity factor. Such an electrolyser would be large by current standards (the largest electrolyser in the world is 150 MW) but within the range of projects planned for the coming decade (*e.g.* HyDeal Ambition aims for 67 GW, a 45 GW project has been announced in Kazakhstan, CWP Global plans to build a 30 GW Power-to-X plant in Mauritania). Further scale increases to 1.5 $MtH_2$/year could bring the transport cost of all carriers to the USD 1.6-2.7/$kgH_2$ range (IRENA, 2022b).

To achieve the rest of the cost reduction, other levers beyond economies of scale are needed. One such lever is lower project risks as different stakeholders develop experience with the technologies, which in turn translates into lower WACC for these projects. A change from 15% (or more) to 5% in WACC can further decrease the cost of shipping hydrogen by 25-45%. Another lever is learning-by-doing, which refers to implementing lessons from deployment, standardising the design and, in general, going from individual projects that require specific design to a replicating modality can further reduce the costs by 35-60%. The last lever is innovation, which is considered in the form of lower energy consumption for ammonia cracking, LOHC dehydrogenation, hydrogen liquefaction and engine efficiencies for the ships. The effect this will have will depend to a large extent on the assumption for the electricity and heat source used for reconverting the carrier back to hydrogen at the importing terminal. If a cost penalty of USD 60/MWh is used for the energy consumed for this reconversion, then the cost decrease for technology improvement is 35%, 19% and 15% for ammonia, LOHC and liquid hydrogen, respectively, to reach levels of USD 0.7-1.6/$kgH_2$ for the total transport cost. The steps in Figure 3.5 are shown separately for illustration purposes. In reality, these stages are highly intertwined and will most likely develop in parallel. While the largest single contributor to cost reduction is expected to be economies of scale, the potential of the other cost levers should not be overlooked, making it essential to focus on financing strategies, R&D and the supply chain to achieve low costs in the long term. For more details on the cost assessment and drivers for reduction, see: IRENA (2022b).

During the transition period to 2050, two factors will limit trade. First, the WACC differential across regions is the opposite of what is needed to drive trade. Today, the prospective importing countries, Germany, Japan and the Republic of Korea, are among the countries with the lowest WACC for renewable technologies (IRENA, 2021b). In contrast, some of the prospective exporters like North Africa, Ukraine and some countries in Latin America (including Argentina, the Plurinational State of Bolivia, Costa Rica and Ecuador) are among the places with the highest WACC.[12] This means that the best chances for trade, based solely on this parameter, will be in the longer term when the WACC differences have potentially attenuated (yet not disappeared) and the production cost differential is driven more by the quality of the resources than the affordability of finance. Intermediate years (*i.e.* 2030-2040) will see increasing incentives for

[11] *USD 6.5/$kgH_2$ for LOHC, USD 8/$kgH_2$ for ammonia, USD 17.3/$kgH_2$ for liquid hydrogen. Refer to IRENA (2022b) for details.*

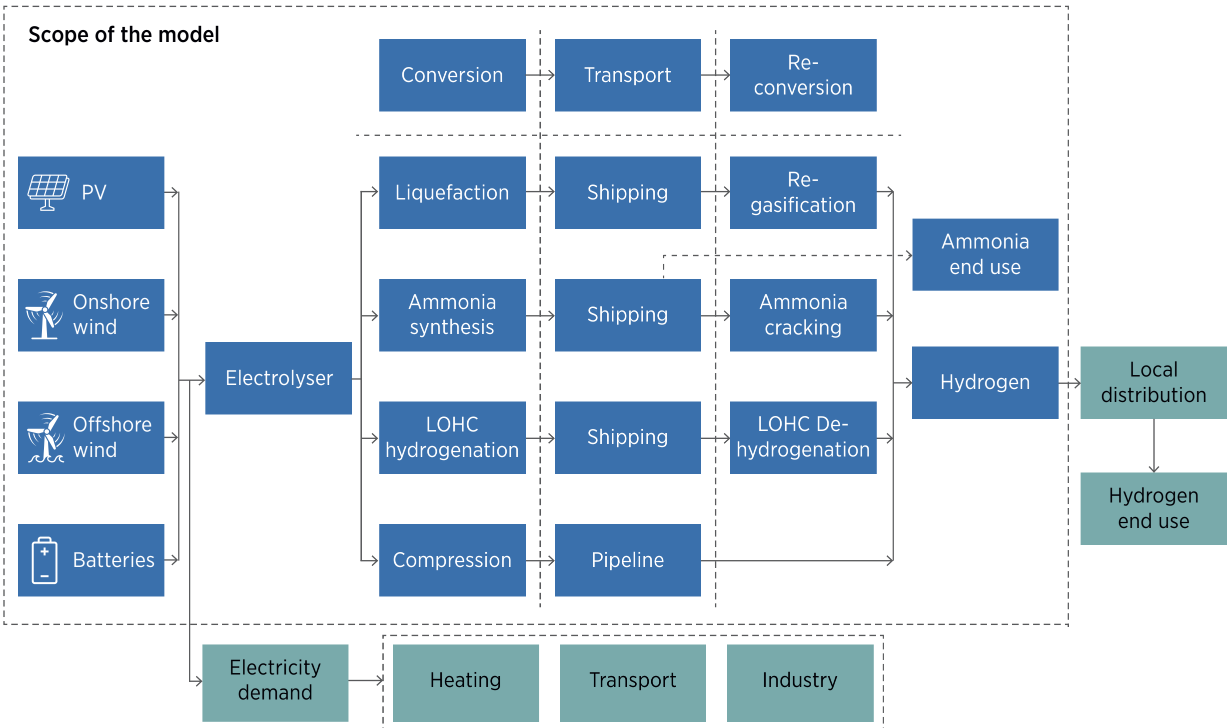
[12] *There are also exceptions to this, with Australia and Chile having a WACC of 3.7-4.6% and 5.2%, respectively.*

trade, yet lower than in 2050. This study explores the two extremes (see Section 3.8). One where the risk profiles and WACC remain the same as they are today (Egli, Steffen and Schmidt, 2019) and one where all the countries have the same WACC (Bogdanov *et al.*, 2019). Second, transport costs might still be high (depending on the speed of innovation) and the comparison between production and transport costs might still not be favourable. Thus, the trade in 2030, when costs will most likely still be relatively high and domestic potential might not yet be fully used, is expected to be limited. Instead, the trade in 2030 will likely be driven by large pilot projects between exporters with good resources and favourable financing conditions and importers with energy or climate policies in place, to pay for the extra cost of green and blue hydrogen compared with grey.

## 3.2 Introduction to modelling results

The analysis was conducted using a global optimisation model that covers both power and gas systems and co-optimises the investments, the gas shipping and the dispatch of the combined power and gas system. The scope of the model[13] goes from renewable generation to hydrogen, transport and end use (see Figure 3.6). Resource data for PV, onshore wind and offshore wind (from the analysis described in IRENA [2022c]) is split into five resource classes for each region, with a maximum potential and a representative hourly profile. Given that the methodology is based on least-cost optimisation, trade flows are driven purely by delivered cost. In the future, hydrogen trade flows will also be largely shaped by geopolitical factors, especially if the production cost differentials between regions are small and geopolitical preferences would result in only small cost penalties, in exchange for lower risk of supply disruptions (IRENA, 2022d).

**FIGURE 3.6. Scope of modelling framework (blue boxes) used for global hydrogen and ammonia trade**




Note: Importing and exporting terminals also include the cost of storage. This has not been added to the figure for simplification purposes. LOHC = liquid organic hydrogen carrier; PV = photovoltaic.

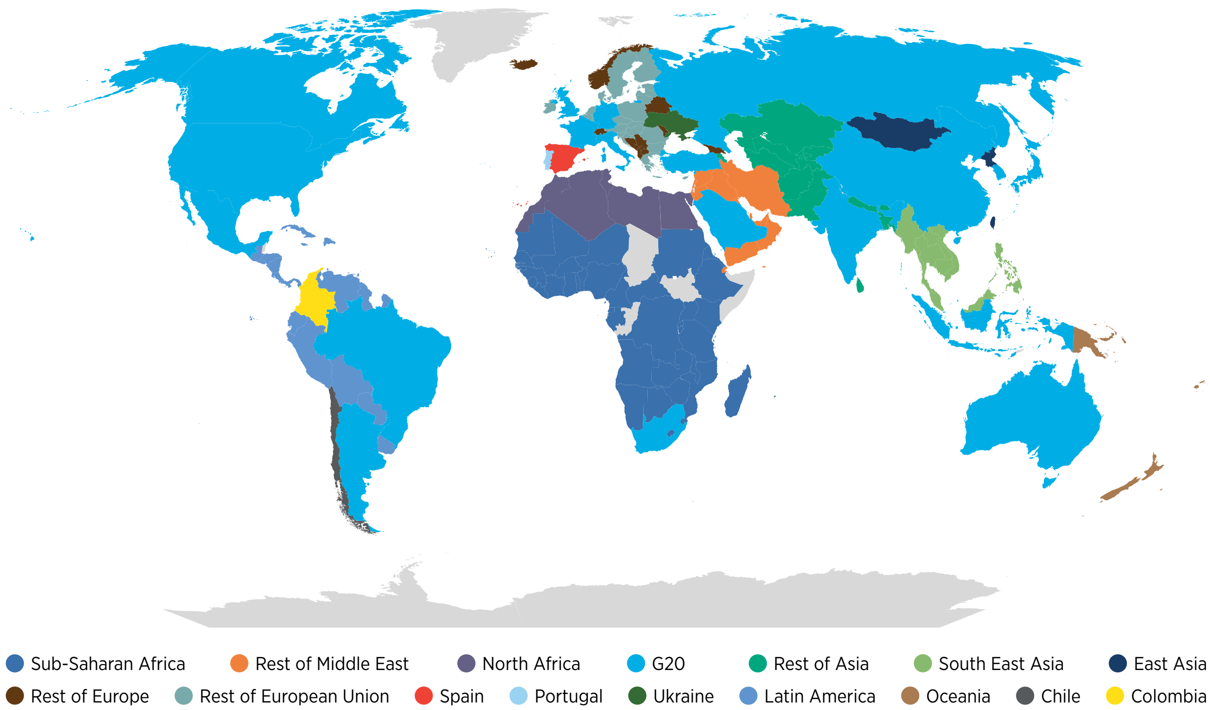
[13] *Developed using the commercial modeling tool PLEXOS.*

In this analysis, the model is considered as greenfield. This means there is no installed capacity for any of the components and all the hydrogen production requires new facilities. For regions that have natural gas pipelines today, a lower cost has been considered equivalent to repurposing them to hydrogen. The model is not bound only by the existing pipelines; new hydrogen pipelines are possible for new routes. The model optimises investment and operation of the combined power and gas system, but only to feed hydrogen and ammonia demand (this excludes electricity demand beyond electrolysers and gas processing plants). This means only off-grid electrolysers are included. On-grid electrolysers can have other challenges such as the continuous tracking the emissions of the electricity input and additional costs from connection to the grid, taxes and levies in the wholesale price. The objective function is thus to minimise total cost, and the routes are compared based on this criterion and not others (*e.g.* efficiency, which is indirectly reflected in cost).

The objective of this analysis was to focus on green hydrogen production and trade driven by resource quality and cost differentials, rather than legacy power system differences. The renewables potential has been reduced to account for installed capacity dedicated to the power sector in the WETO 1.5°C scenario.

The time horizon is 2050, and demand and CAPEX are those assumed for that year (see Chapter 2 and IRENA [2022c]). To make both the calculation of the flows and the interpretation of the results easier, the model is divided in 34 regions (see Figure 3.7): each G20 country, selected regions that could play a significant role in hydrogen trade (Chile, Colombia, North Africa, Portugal, Spain and Ukraine), and the rest of the countries aggregated by geographical location (*e.g.* East Asia, Latin America).

**FIGURE 3.7. Country aggregation into regions in the global hydrogen trade model**




Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

The model does not include electricity grid expansion within or between nodes. Each node is assumed to have a maximum grid expansion, although it is recognised that in many countries achieving such expansion might be challenging (*e.g.* because of social opposition, permitting, project delays, lack of market incentives), especially in densely populated areas. Energy exchange through hydrogen pipelines and ships, although less efficient, has a larger transport capacity, provides diversification of energy supply, and is potentially less challenging in terms of the necessary conditions for infrastructure and markets, especially where existing natural gas pipelines can be repurposed to transport pure hydrogen.

## 3.3 Green hydrogen production

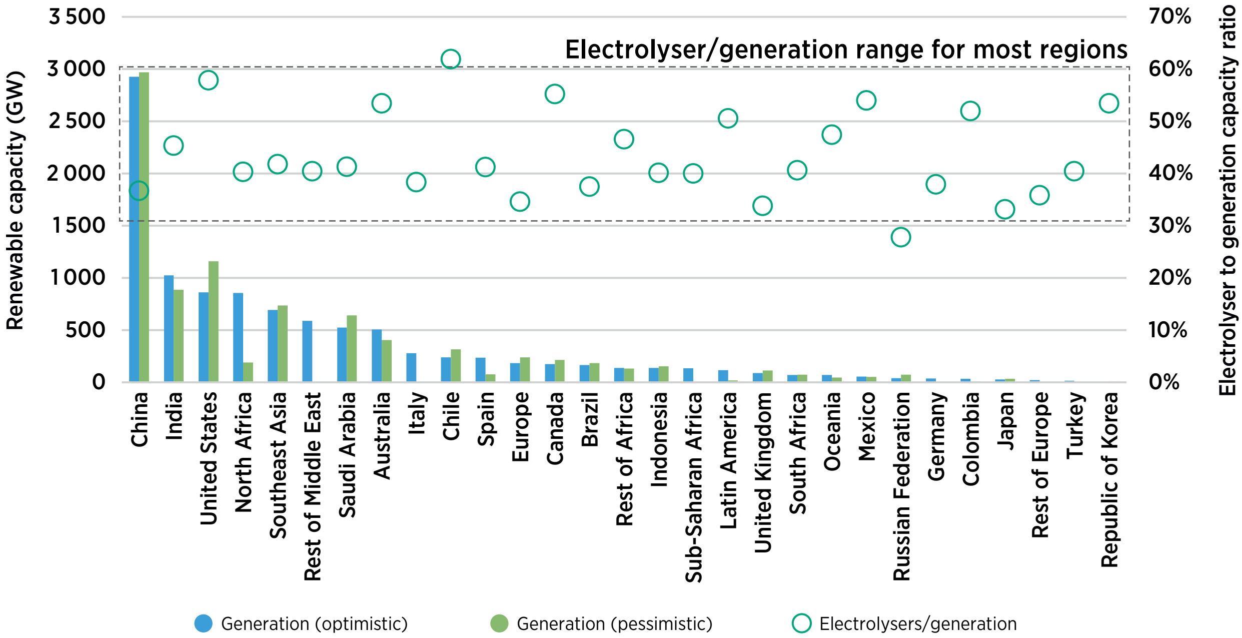
The potential for green hydrogen production at costs lower than USD 2/kg$H_2$ is almost 10 000 EJ/year by 2050 (over 24 times the global final energy demand in 2020) (IRENA, 2022c). However, several factors could constrain this very large potential. First, the potential is not equally distributed across countries, and some (*e.g.* Germany, Japan, Republic of Korea) have much lower potential than the expected future needs. Second, the low-cost supply locations can be in remote places with limited infrastructure (*e.g.* roads, grid, pipelines), which would increase the costs due to the facilities and additional transport infrastructure needed. Third, the additional transport cost to the importing markets may reduce attractiveness by increasing overall cost significantly.

Figure 3.8 shows the power generation capacity installed to produce green hydrogen and the associated electrolyser capacity. Although capacity varies significantly, the optimal electrolyser capacity is between 30% and 60% of the power generation capacity, depending on the share of PV versus wind, capacity factors of PV and wind, battery installed capacity, and seasonality of resources, among other factors. In total, 10 280 GW of solar and wind are installed to supply electricity to 4 400 GW of electrolysers, with a global average ratio of 43%. Most of the renewable generation is from solar for both scenarios due to the combination of CAPEX for PV and onshore wind.[14] The lower CAPEX from PV makes it more attractive than onshore wind despite the lower capacity factors. This also happens in the *pessimistic* scenario, which uses a higher CAPEX (over USD 300 per kW of electricity input [$kW_e$]) for the electrolyser, resulting in a higher cost penalty due to lower operating hours of the electrolyser.

The electrolyser to generation capacity ratio is determined by a combination of the capacity factor of the renewable generation, capital cost, WACC and use of batteries. For example, one of the lowest values in Figure 3.8 is Japan, with a capacity ratio of almost 30% between the electrolyser and the renewable generation. This happens because Japan has a relative high capital cost for PV (USD 445/kW versus a global average of almost USD 300/kW). This makes electricity generation expensive, which would make curtailment and oversizing more expensive. Therefore, batteries are installed to increase the effective capacity factor of generation, installing about 18.4 GW of batteries in comparison to 41.8 GW of renewable capacity and 11.7 GW of electrolysers. This is in contrast to, for example, Chile, which has the highest ratio (62%), good quality in resources (annual capacity factor of 0.22), an average capital cost (USD 312/kW) and a low WACC (4.3%), resulting in a low electricity price and a low-cost penalty for oversizing the renewable capacity.

[14] *Global averages of almost USD 300/kW for PV and USD 870/kW for onshore wind for the optimistic scenario and USD 355/kW for PV and USD 965/kW for onshore wind for the pessimistic scenario.*

**FIGURE 3.8. Installed renewable generation capacity for hydrogen production and associated electrolyser capacity by region in 2050 for *optimistic* and *pessimistic* scenarios**



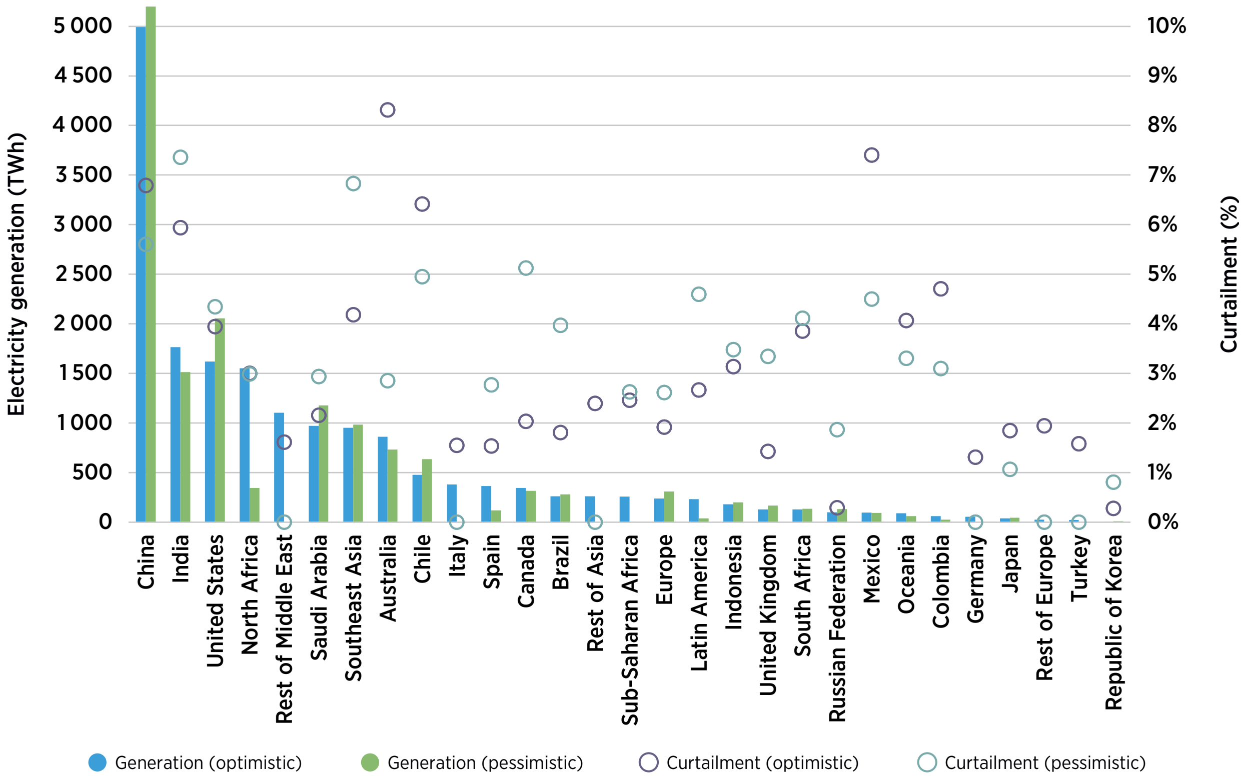

The renewables capacities shown in Figure 3.8 are substantial considering this is only for hydrogen production and not for the bulk of electrification. By the end of 2021, the global renewable capacity stood just over 3 000 GW, out of which roughly 1 700 GW were from wind and solar, which have the potential to become the main suppliers of electricity for hydrogen. China has the largest requirement, at 3 000 GW by 2050. To put this into perspective, China has set a goal of 40% electricity from non-fossil fuel generation by 2030 in parallel to a 1 200 GW target for wind and solar PV by 2030, noting that it has surpassed the previous targets set in its 12$^{th}$ and 13$^{th}$ five-year plans. China is entering an acceleration phase, where annual deployment has continuously increased. In 2021, China increased the global offshore wind capacity by almost 50% and reached a total capacity of over 600 GW for wind and solar. The United States already had 235 GW of wind and solar capacity by the end of 2021, with an annual deployment of about 30 GW/year in the last two years. To reach a net-zero target by 2050 and a decarbonised power sector by 2035, this pace needs to accelerate to at least 60-70 GW/year (White House, 2021). India has announced a renewable capacity target of 500 GW and a target of 50% of electricity from non-fossil fuel generation by 2030.

For these countries it seems that renewable capacity will be challenging yet achievable; others will require a massive expansion of their current renewable capacity. Within North Africa, Morocco supplies about 40% of its electricity demand with renewables and has targets of 52% by 2030 and 80% by 2050. By the end of 2021, it reached a total renewable capacity of 4.3 GW, increasing at less than 10%, or 0.4 GW, annually. This reality is in stark contrast with what would be needed to become a key hydrogen supplier to Europe, which would require over 850 GW of renewable capacity by 2050. Australia only supplies about a quarter of its electricity with renewables and has a total renewable capacity of 35 GW and an annual deployment of about 6-7 GW. The average electricity demand was just above 31 GW in 2021. In contrast, Australia would need above 500 GW of renewables just to export hydrogen. By the end of 2021, Chile had 7.6 GW of wind and solar (12.5 GW of renewable capacity in total), with an accelerated deployment pace that adds up to 4.3 GW of wind and solar projects under construction, to come online by 2024, and more than 10 GW of new generation that has received environmental approval (CNE, 2022).

By 2050, Chile would require at least 250 GW of renewable capacity for hydrogen and ammonia export. Thus, to realise this future, these countries would require not only a tremendous increase of the historical pace and adjustment of future plans but also the development of an export-oriented industry that is multiple times larger than the total domestic energy consumption.

Flexible operation of electrolysers, together with some battery storage, where economically optimal to be added, can result in low curtailment rates for solar and wind (see Figure 3.9), even with an installed renewable capacity more than twice that of electrolysers. Curtailment levels between 0.3% and 8.3% of the potential generation are cost optimal. This means it is more cost-effective to curtail part of the electricity than to make an extra investment in a larger electrolyser but only operate such marginal capacity for a few hours in the year.

**FIGURE 3.9. Electricity generation for hydrogen production and curtailment by region in 2050 for *optimistic* and *pessimistic* scenarios**

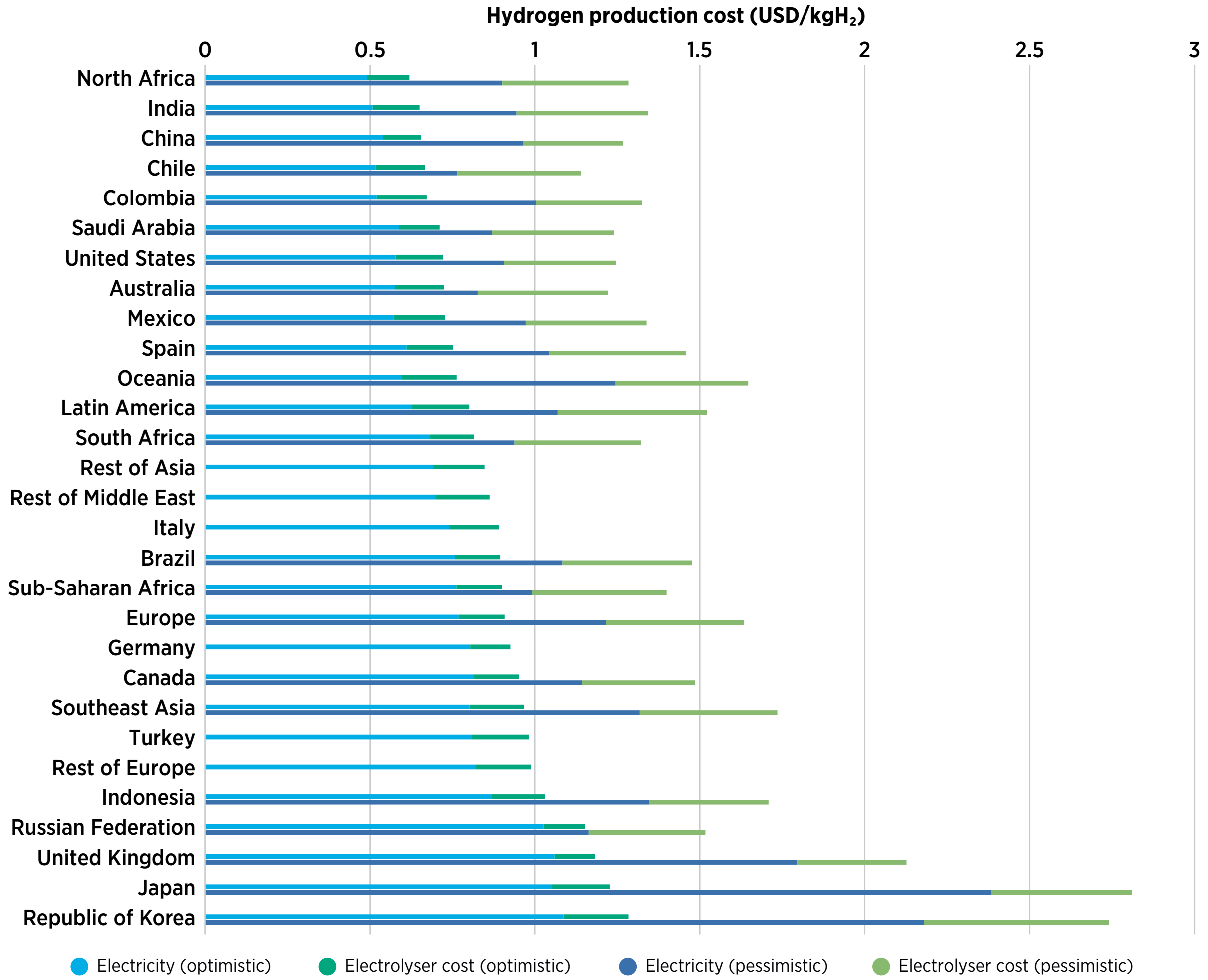



To achieve the necessary low costs in the future, there must be innovation to improve the technologies and economies of scale to achieve mass manufacturing, global supply chains and low costs. Areas of attention for electrolysis are efficiency and capital cost. Reaching 14 TW of PV and over 8.1 TW of wind would enable a CAPEX reduction of over 70% and 50%, respectively, in comparison to 2020 levels. This would make CAPEX as low as USD 225/kW possible for PV in countries with the lowest capital costs, which would mean a cost of almost USD 10/MWh for the places with the best resource quality (equivalent to about USD 0.45/kg$H_2$ considering the efficiency losses). Similarly, onshore wind could reach levels of USD 15/MWh in the best sites, with the additional advantage of a higher number of operating hours. Also, in a future where installed electrolysis capacity increases by a factor of almost 15 000 compared to today,[15] electrolyser

[15] *Current capacity is about 0.7 GW, in comparison to the 4 400 GW needed by 2050 under optimistic assumptions (alternative scenarios have a similar capacity or larger).*

costs could reach levels as low as USD 130/$kW_e$. With a capacity factor between 30% and 60% (see Figure 3.12), the contribution of electrolyser cost to hydrogen cost per kilogramme would be between USD 0.08/$kgH_2$ and USD 0.16/$kgH_2$, or between 8% and 19% of the levelised cost of hydrogen. With these considerations, the places that combine good-quality resources with low capital cost and low WACC (*e.g.* Chile, China, Colombia, India) can reach production cost levels below USD 0.7/$kgH_2$ (see Figure 3.10). These are only bare technical production costs,[16] and transport cost to demand centres needs to be considered on top. For some countries, the best renewable resources are far from these centres, which could significantly increase the cost. One example is China, which reaches a production cost below USD 0.7/$kgH_2$ in the east of the country, while all the population centres and industrial demand are in the west of the country. The costs shown in Figure 3.10 for regions are average values. Countries within a region will have more extreme (both lower and higher) values. For instance, analyses for the United Arab Emirates find a hydrogen production cost of USD 1-2/$kgH_2$ already by 2030 and USD 0.4-1.7/$kgH_2$ by 2050 (Gandhi, 2022).

**FIGURE 3.10. Levelised cost of hydrogen by region in 2050 for an *optimistic* and *pessimistic* scenario**



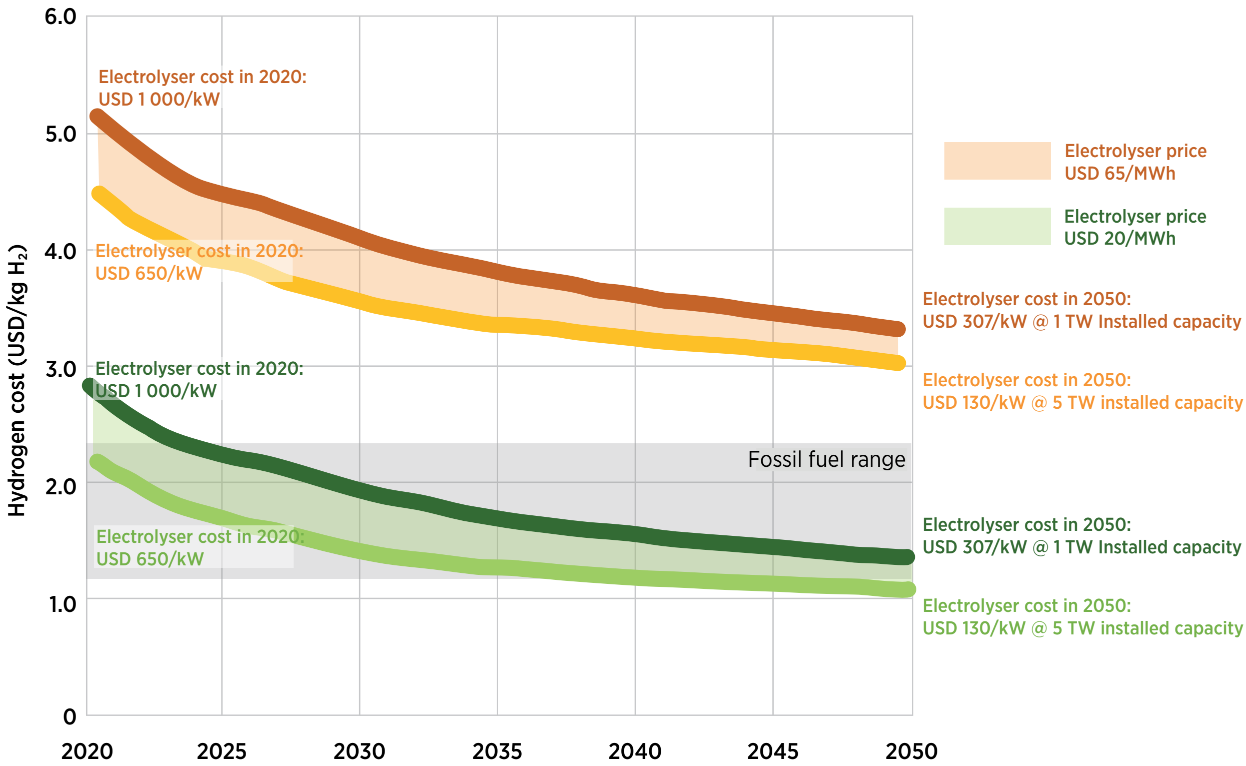

Note: Optimistic capital expenditure assumptions for 2050: photovoltaic (PV): USD 225-455/kW; onshore wind: USD 700-1 070/kW; offshore wind: USD 1 275-1 745/kW. Pessimistic: PV: USD 271-551/kW; onshore wind: USD 775-1 191/kW; offshore wind: USD 1 317-1 799/kW. Electrolyser: USD 130-307/kW. Weighted average cost of capital as per 2020 values without technology risks across regions. Green hydrogen potential is based on assessing land availability for solar PV and wind. Fixed operational expenditure: 1% (solar PV), 3% (onshore wind), 2.5% (offshore wind) (percentages are a function of capital cost).

[16] *Aspects such as engineering costs, land costs, contingency, and profit margin for manufacturers are not included for the electrolyser but are included for renewable generation.*

Every region in Figure 3.10 has a supply cost curve with a continuously increasing cost as supply is used (IRENA, 2022c). Once the optimal production level from each region is defined based on the hydrogen demand and trade, the optimal point has a single cost, which is the one reflected in Figure 3.10. For the supply cost curves for each region under different scenarios, refer to (IRENA, 2022c).

These costs are in line with previous IRENA analysis (IRENA, 2020b) on the relative importance of electricity and electrolysis as the cost of electrolysers decreases (see Figure 3.11). Based on the current analysis, dedicated, large-scale solar and wind facilities for hydrogen generation will be able to supply electricity to electrolysers at a cost of USD 10-20/MWh in all countries and regions by 2050, with many regions expected to reach costs of green hydrogen well below USD 1/kg for the *optimistic* scenario and USD 1.5/kg for the *pessimistic* scenario.

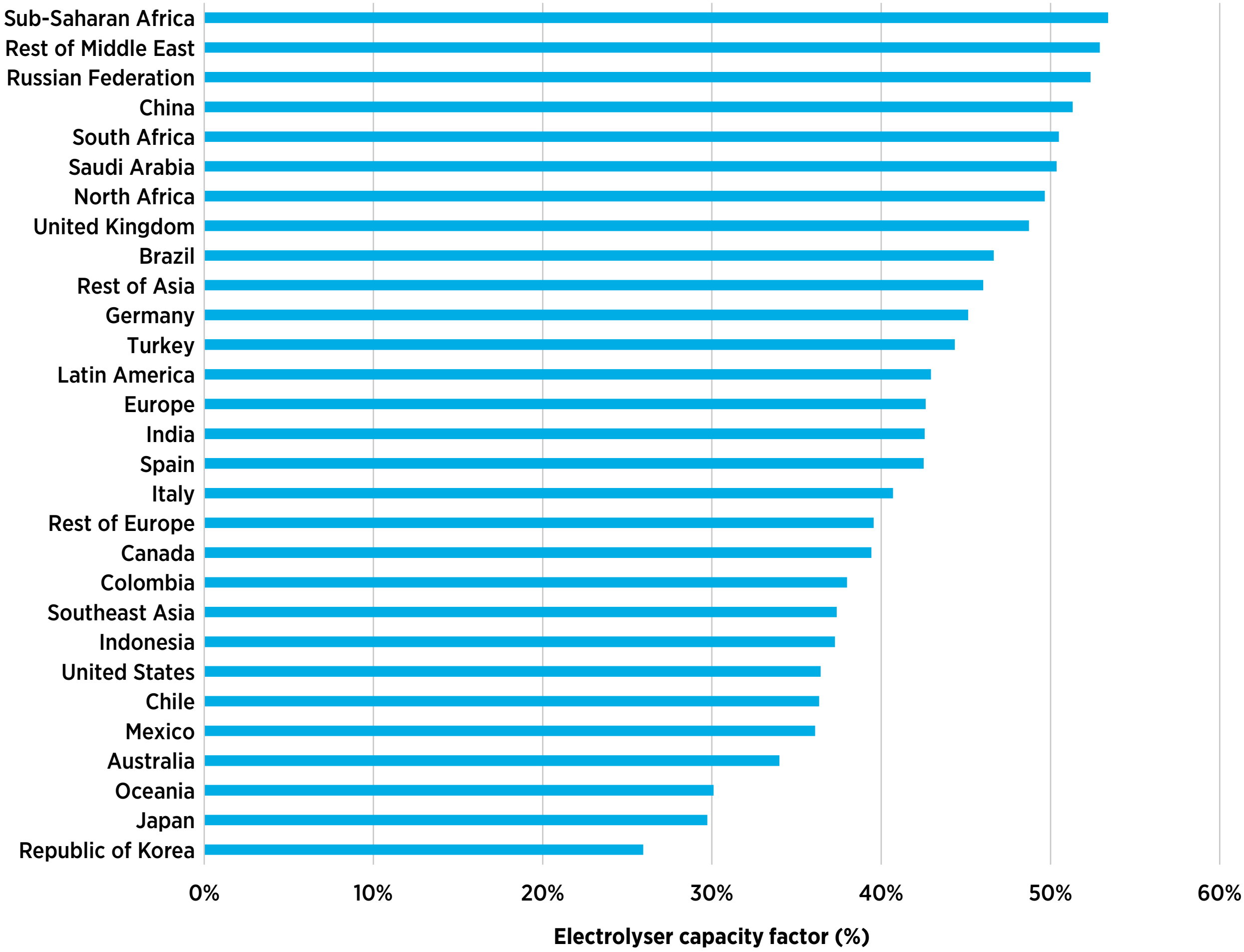
**FIGURE 3.11. Cost reduction potential for green hydrogen until 2050 for various scenarios and conditions**




Source: IRENA (2020b).

Given the low cost of electricity, the optimal sizing of electrolysers may be higher than initially expected, resulting in comparatively low capacity factors for electrolysers, between 25% and 53% (see Figure 3.12), still producing hydrogen at costs in the range of USD 0.6-1.2/kg$H_2$ (see Figure 3.10).

**FIGURE 3.12. Electrolyser capacity factor by region in 2050 for the *optimistic* scenario**

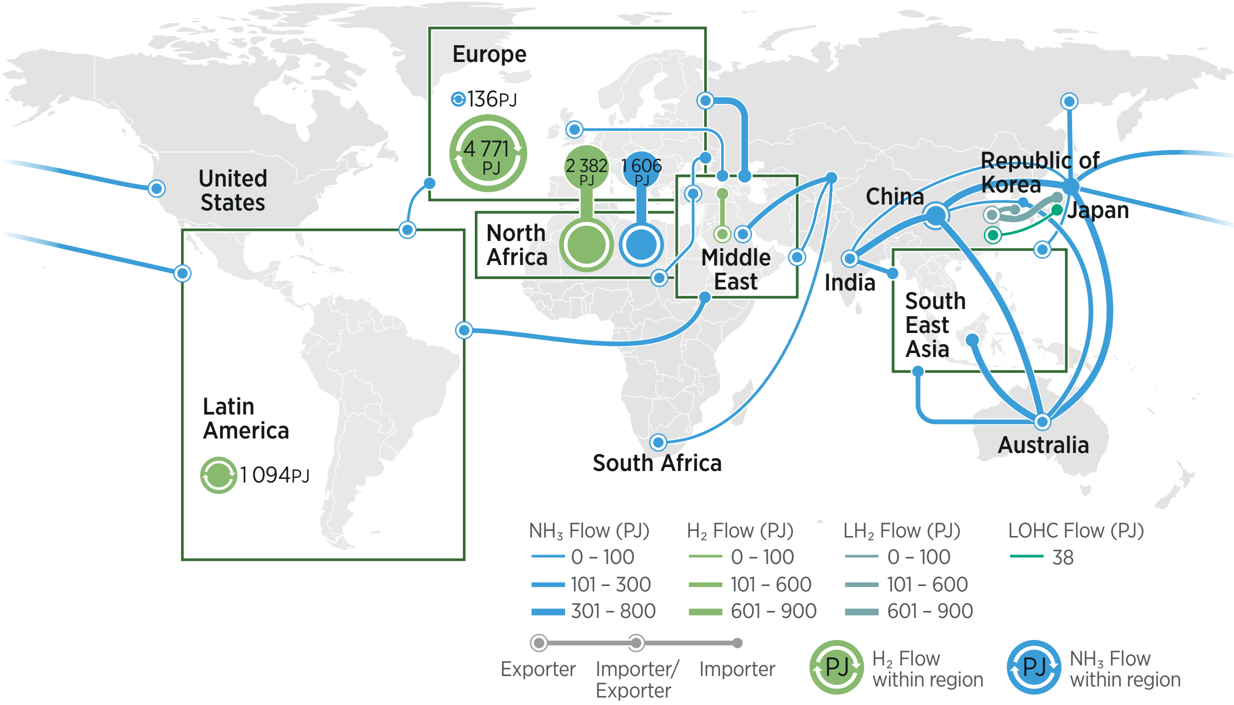



## 3.4 Estimated trade volumes of hydrogen and derivatives

Figure 3.13 reflects the cost optimal global hydrogen trade flows in 2050 (excluding other factors from Figure 1.8), based on a hydrogen demand of about 50 EJ/year (about 420 $MtH_2$/year). This excludes the share of hydrogen used for power generation, which is expected to be mostly from domestic production, and the share used to provide seasonal storage for renewable power and to ensure system adequacy during periods of continued low renewable generation. Notable exceptions are Japan and the Republic of Korea, which are very constrained in land availability and will potentially import hydrogen (derivatives) for power generation[17] as well (see Figure 3.3). Figure 3.13 also considers *optimistic* assumptions for the techno-economic performance of all the technologies, representing a future where innovation and international collaboration have been successful in tackling the barriers that hinder technology from reaching its full potential (IRENA, 2022b).

[17] *In February 2022, JERA, the largest power generation company in Japan announced plans to buy up 0.5 $MtNH_3$/year from long-term contracts starting in 2027-2028.*

**FIGURE 3.13. Global hydrogen trade map under *optimistic* technology assumptions in 2050**




Note: Optimistic capital expenditure assumptions for 2050: photovoltaic (PV): USD 225-455/kW. Onshore wind: USD 700-1 070/kW. Offshore wind: USD 1 275-1 745/kW. Electrolyser: USD 130/kW. Weighted average cost of capital as per 2020 values without technology risks across regions. Green hydrogen potential is based on assessing land availability for solar PV and wind. Demand is in line with a 1.5°C scenario from *World Energy Transitions Outlook 2022* IRENA (2022a).

Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city, or area or of its authorities, or concerning the delimitation of frontiers or boundaries.

In 2050, about 18.4 EJ/year of green hydrogen, or about 36% of the overall 50 EJ/year, is globally traded; 4.5 EJ/year of these flows are re-exported (*i.e.* transit countries), contributing to larger traded flows. This takes place roughly 55% through hydrogen pipelines, 40% through ammonia shipping and 5% as liquid hydrogen. Trade as LOHC is negligible at less than 0.1 EJ/year. To put this 36% of trade into perspective, in 2020, about 74% of oil, 33% of gas,[18] 19% of coal, 3% of electricity, 22% of steel, 10% of ammonia, 28% of methanol and 10% of toluene (a potential LOHC) were globally traded (BP, 2021; Daiyan, R, Hermawan, M and Amal, R, 2021; IEA, 2020a, 2020b; OECD, 2020). The ammonia share traded in 2050 corresponds to 7.4 EJ/year and would be equivalent to more than two times the total global ammonia production (183 Mt/year or 3.4 EJ/year), or almost 25 times the current global ammonia trade. This trade would still be about 60% lower than the liquefied natural gas (LNG) trade in 2020. The growth is much more modest when the pipelines are considered. The 9.8 EJ/year traded by hydrogen pipelines globally would be 30% higher than the gas imports by pipeline into Europe in 2020, or just about a quarter of the global natural gas cross-border transport by pipeline in 2020.

Hydrogen pipelines are mostly used for regional trade, with two major distinct networks: Europe and Latin America. In Europe, there is already a vast gas transmission network of over 200 000 km (Rodríguez-Gómez, Zaccarelli and Bolado-Lavín, 2016) that could potentially be repurposed to hydrogen, representing the cheapest transport option for hydrogen. The hydrogen flow in Europe is mostly south to north. The cost of hydrogen production from PV in the south of Europe plus transport to Northwest Europe is much lower than producing hydrogen from

[18] *24% excluding inter-regional trade, increasing to 32.5% if such trade is included as well.*

offshore wind (which would require a shorter but more expensive offshore pipeline). Further to the south, in North Africa, there are already multiple pipelines connecting to Europe that are used today to transport natural gas. Europe imported as much as 1.8 EJ of natural gas from North Africa in 2018 (both through pipelines and LNG). From Algeria and Libya to Italy and Spain, these pipelines have a cumulative capacity of 63.5 billion cubic metres (bcm) per year (equivalent to more than 60 GW,[19] as opposed to only 1.4 GW of transport capacity for electricity) (Timmerberg and Kaltschmitt, 2019). This would be more than enough capacity to satisfy the EU 2030 targets and provide a low-cost transport option in the most critical phase of development. Thus, there is a role for Italy and Spain as regional hubs between North Africa and Europe. The HyDeal España project targets 7.4 GW of electrolysis by 2030, and although it is mostly for domestic consumption, it is a sign of the massive plans for Spain that could make the country a key supplier to the rest of Europe. Europe is well positioned between different potential suppliers (by pipeline and shipping) and would face a relatively small cost penalty for switching suppliers. Thus, other factors beyond pure cost will have a large influence in defining Europe's trading partners for hydrogen.

In Latin America, there is no regionwide natural gas network, and interconnection capacities are rather limited. This analysis shows that main pipelines connecting some countries, potentially with a southern and a northern network because of the large distances, could be attractive. This would still be far from a regionwide network and would only connect countries that can build a large domestic demand to complement the export market: Chile to Argentina and Brazil, Uruguay with Argentina, Colombia with the Bolivarian Republic of Venezuela.

Sub-Saharan Africa and central Asia have a very limited role in trade due to the high WACC, which makes production expensive. Thus, exports are not only based on potential (a large one in sub-Saharan Africa) but on hydrogen production costs (see Figure 3.1).

The Middle East is endowed with rich renewable resources and a combination of onshore wind and solar PV can support high utilisation factors. Countries such as Israel, Kuwait, Saudi Arabia and the United Arab Emirates already have low WACC today, facilitating their role as exporters. Other countries in the region would need to tackle the high WACC and development of the renewable industry to become competitive in the export market.

Some challenges need to be considered when repurposing natural gas pipelines to hydrogen IRENA (2022b). The main aspects to consider are material suitability, compression needs and pipeline capacity. Regarding materials, the main challenge is hydrogen embrittlement, which affects steel properties and failure behaviour. The susceptibility depends on the specific type of steel[20] and needs to be assessed on a case-by-case basis. Compression power for hydrogen is three to four times higher than for natural gas due to its lower volumetric energy density and the larger volumes handled. Investment costs for the hydrogen compressor can be 40-80% higher than for natural gas, although still representing less than 1.5-2% of the transported energy for every 1000 km in most cases (Guidehouse, 2020).[21] For an existing pipeline (*i.e.* same diameter) and a fixed pressure drop, the energy transport capacity with hydrogen is 80-98% of the energy capacity of the natural gas pipeline (Haeseldonckx and Dhaeseleer, 2007).

[19] *Capacity of 71 GW for natural gas (assuming a lower heating value of 40 MJ/m$^3$) and 60 GW for hydrogen.*

[20] *X52 and lower grades (as per API 5L standard) are less susceptible to hydrogen embrittlement, while X70 and higher grades are more prone to it. The yield strength can also be an indicator of susceptibility, with 360 megapascals as the threshold (lower yield strengths are better).*

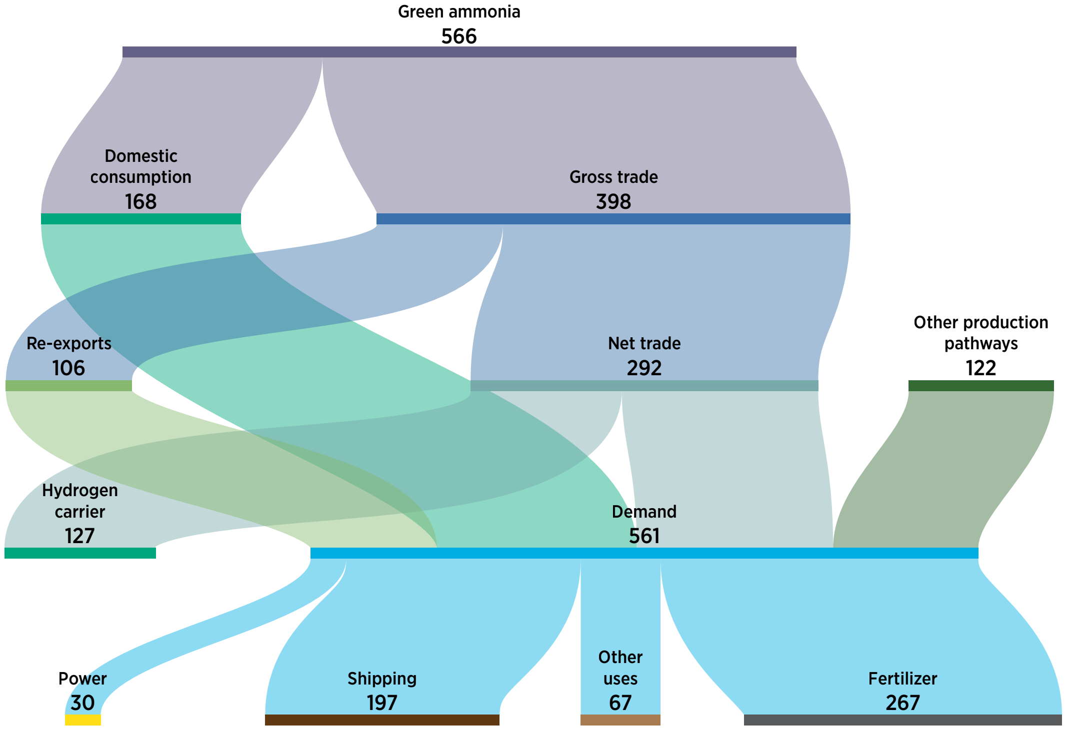
[21] *Compressors would use the local electricity grid rather than the energy in the transported hydrogen, so this is just to put the energy consumption into perspective.*

For regions with gaseous hydrogen, underground storage will be critical. Storage can compensate for the variability of wind and solar production, increase the resilience of the system, improve capacity adequacy when used as long-term storage, and decrease the price spikes. Storage, however, needs early planning and investment, as repurposing storage from natural gas to hydrogen can take up to seven years and constructing new storage up to ten years (GIE, 2021). Hydrogen storage needs could be partially satisfied with existing natural gas assets. Some limitations, however, are that a repurposed facility would only store about one-quarter of the energy (versus natural gas) due to the energy density differences and the fact that most of the current global storage capacity is in the form of depleted oil and gas fields, and further research is required to de-risk their use for hydrogen (IRENA, 2022b).

These results reflect the regional aggregation in this study (see Figure 3.7) and trade flows could be more significant for specific countries once the regions are disaggregated. For instance, some analyses show that the hydrogen demand in the United Arab Emirates could grow from about 0.8 $MtH_2$/yr today to almost 11 $MtH_2$/yr in 2050, with almost two thirds of that demand for exports (Gandhi, 2022).

Ammonia, on the other hand, is mostly expected to cover long-distance trade. For ammonia, the global demand grows from 183 Mt/year today to almost 560 Mt/year by 2050, mainly driven by the use of ammonia as fuel for international shipping (IRENA, 2021e) and growth in developing economies for use as an industrial feedstock (IRENA & AEA, 2022). Additionally, 130 Mt/year of ammonia is needed as a hydrogen carrier (*i.e.* to be reconverted to hydrogen). Almost 80% of the ammonia supply is expected to be green ammonia.[22] About two thirds of the green ammonia supply (400 Mt/year) is globally traded, while the rest is used for domestic demand (see Figure 3.14). This means more ammonia is traded to be ultimately used as feedstock or fuel rather than as a hydrogen carrier. This reflects the large impact that ammonia cracking has (nearly doubling the transport cost) and the importance of decreasing the costs associated with cracking.

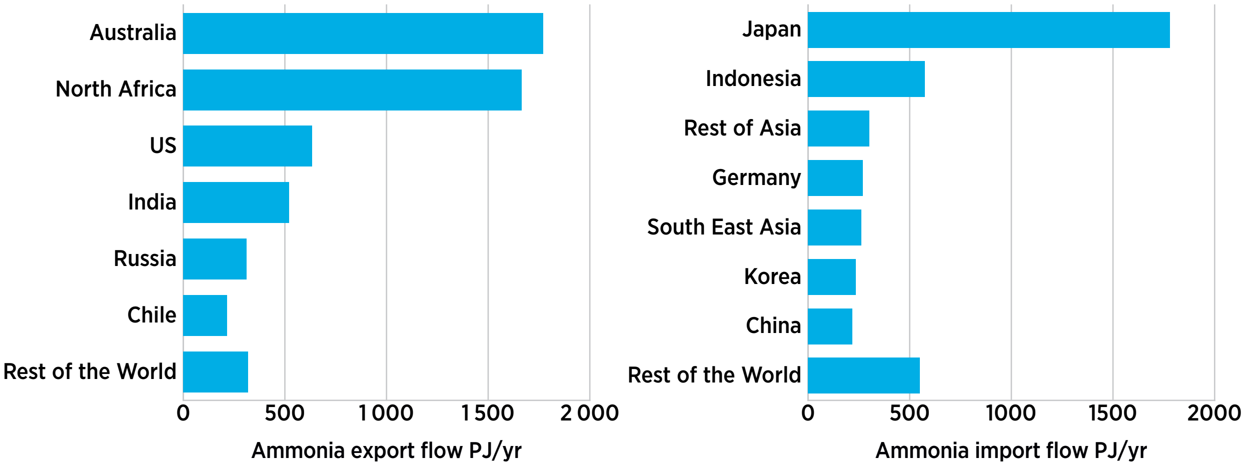
**Figure 3.14. Global energy balance for ammonia in an *optimistic* technology scenario in 2050**




[22] *The other 122 Mt/year is met with other low-carbon pathways, including bioenergy and fossil fuels with carbon capture, utilization and storage.*

The main ammonia exporters are Australia, India, North Africa and the United States. Brazil, Canada, China and Latin America are largely self-sufficient regions. The largest net importers are Germany, Indonesia, Japan, Southeast Asia and the rest of Asia. Some parts of the Middle East are also net importers, mainly defined by a high cost of capital that makes domestic production expensive. For most regions, supply is relatively diversified among various countries, with a relatively close delivered cost. This highlights the benefit of renewable energy, which is ubiquitous, with various countries being able to produce it at low cost, unlike the present situation with fossil fuels (IRENA, 2022d).

**FIGURE 3.15. Export (left) and import (right) markets are relatively concentrated, with the top seven countries representing 96% and 86% of the market, respectively**




The regions with the largest surplus of ammonia production would be Australia, India, North Africa and the United States (see Figure 3.15). In this future, Australia is the main supplier of the Asian region, exporting to China, Indonesia, Japan, the Republic of Korea and the rest of Southeast Asia. Among the countries without an ammonia industry today, Morocco could not only satisfy its domestic demand but could also change to significant exports, while Chile could also arise as one of the main exporters. In this future, Brazil, Canada, China, Spain[23] and the rest of Latin America could become largely self-sufficient regions. India becomes an exporter, driven by the low capital cost and high quality of solar resources, and Indonesia becomes one of the major importers with almost all its demand satisfied with imports due to the high cost of capital of renewables.[24] These results are caused by the relatively low costs that would be achieved by 2050 in a world where innovation and developments have gone according to plan. These results are bound to the geographical resolution used for this study. Once regions are further disaggregated, new exporters could arise. For instance, there are already countries with low WACC in the Middle East (like Israel, Kuwait or the United Arab Emirates) but those do not appear as exporters in this study since they are aggregated into "Middle East" with a high average WACC for the region.

## 3.5 Identifying import and export markets

One way to look at the trade positioning of countries is to compare their hydrogen demand with domestic production (see Figure 3.16). This would roughly create three areas. First, countries that lie close to the boundary line would be self-sufficient. They have enough good-quality renewable resources to meet their hydrogen demand with local production. For those, hydrogen production is a viable proposition to meet their own demand at least cost, with limited need for

[23] *Spain is a major exporter of hydrogen but by pipelines to the rest of Europe, with a smaller trade of ammonia.*

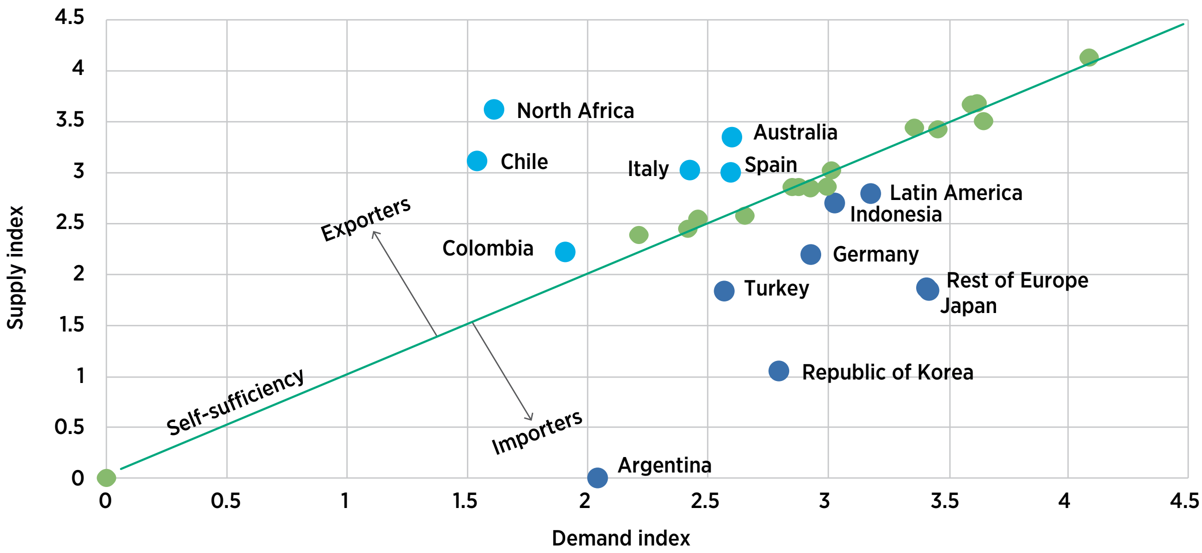
[24] *The reference case assumes the high cost of capital will remain in the future.*

international trade but with some imports and exports for some regions. China and the United States, the two largest consumers of hydrogen by 2050, lie in this area.

Second, countries that lie above the self-sufficiency line incline towards becoming exporters. The further away they are from the line, the larger their production compared with their demand. For these regions, the main proposition is to develop green hydrogen to export their excellent renewable potential and to leverage their mature renewables market to attract investments for more renewable power focused on green hydrogen production and export. These main exporters coincide with the lower cost of hydrogen production in Figure 3.10. Australia, Chile, North Africa and Spain export the largest flows in comparison to their domestic demand.

Third, the area under the self-sufficiency line represents importers: regions where the domestic resources have either higher costs than imported hydrogen or where there is not enough renewable potential to satisfy the domestic demand. The further the countries are from the line, the larger the gap between domestic production and demand. These results only capture the cost dimension; other aspects are captured in the other sections of this report. Thus, the trade for some regions is driven by the cost differential in renewable energy, which in turn is driven by the CAPEX and WACC. For Argentina, Turkey, Ukraine and Latin America,[25] the WACC is relatively high (8-12.5% in 2050). Given that green hydrogen is capital intensive, a higher WACC results in a high domestic production cost and makes these regions importers. Latin America has Chile and Colombia as low-cost (low-WACC) producers, and hydrogen could, in theory, be transported at a low cost through existing pipelines in the region that could be repurposed for hydrogen. Colombia exports almost as much as it consumes (about 80 PJ/year for export and for consumption), about two-thirds in the form of ammonia and one-third through pipelines, but this is a relatively small flow compared with the overall demand for the region. Turkey could be supplied by neighbouring regions with low WACC and excellent resources, such as Saudi Arabia. Some of the countries in this region, as shown in Figure 3.16 (*e.g.* Germany, Japan), are countries with high (grey) hydrogen demand today, linked to industrial production, and will benefit from regional and global markets for hydrogen.

**FIGURE 3.16. Volumes of hydrogen supply and demand for regions around the world in 2050 with *optimistic* technology assumptions**



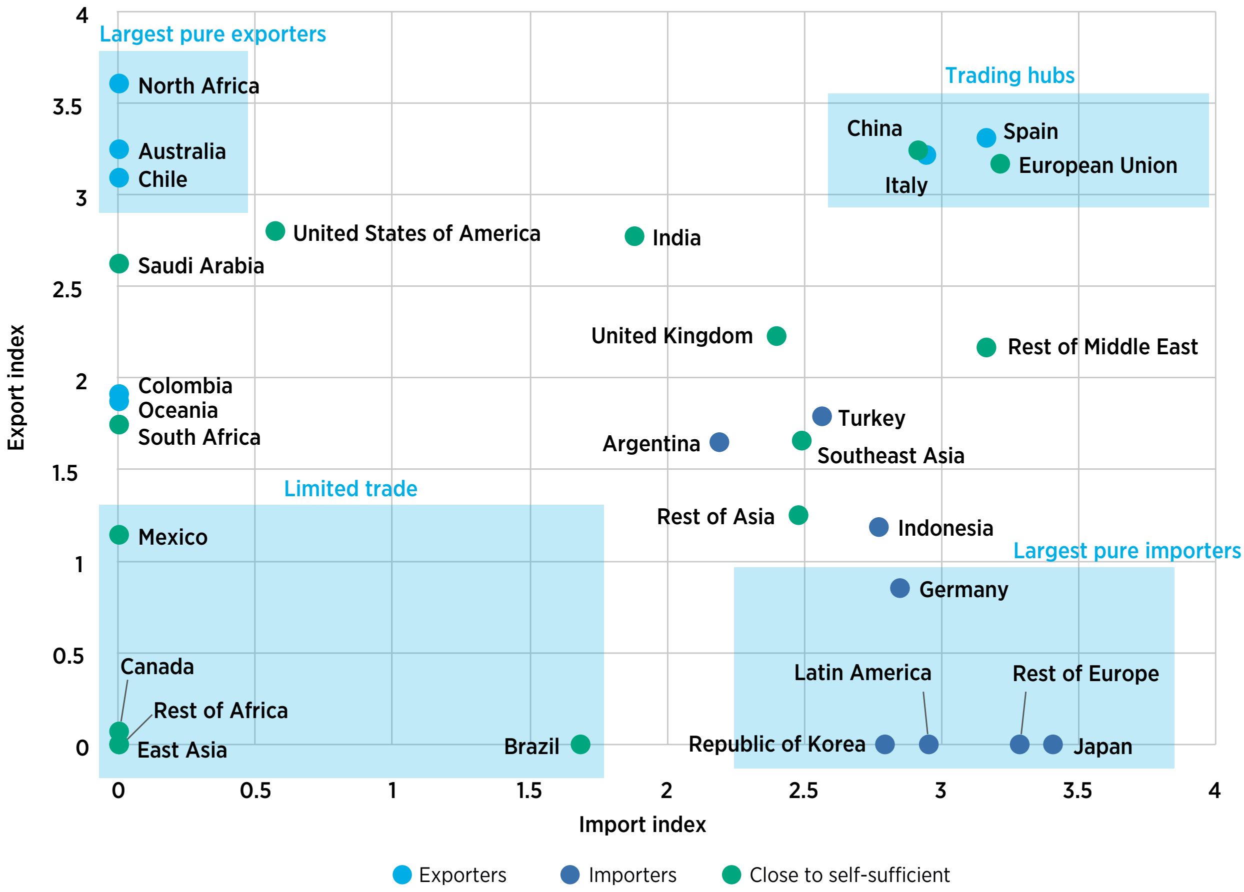

Note: Based on modelling results. Production and demand volumes use a logarithmic function to put the different orders of magnitude on a similar scale. This makes both axes dimensionless, and this could be interpreted as an index rather than as energy flows. The supply index is $LOG_{10}$ of hydrogen production in PJ/year, and the demand index is $LOG_{10}$ of hydrogen plus ammonia demand in PJ/year. Regions that do not explicitly appear in the figure (green dots) are close to self-sufficiency. Only exporters (light blue dots) or importers (dark blue dots) have a name label to improve legibility.

[25] *Latin America excludes Chile and Colombia, which are separate regions in the modelling, increasing the average WACC for the region.*

These results are bound to the geographical resolution used for this study. Once regions are further disaggregated, new exporters could arise. For instance, there are already countries with low WACC in the Middle East (like Israel, Kuwait or the United Arab Emirates) but those do not appear as exporters in this study since they are aggregated into "Middle East" with a high average WACC for the region. For instance, the UAE already has a burgeoning renewables market that has increased by almost eight times since 2017, and it already has plans to export hydrogen and to reach a 25% share of the global hydrogen market by 2030.

Figure 3.16 gives an indication of the difference between production and demand for each region. The trade overview is completed by looking at the import and export flows of each region (Figure 3.17). There are four distinct regions in the chart: (1) regions that lie on the Y-axis, which are net exporting regions, with larger flows as the index increases; (2) countries that lie on X-axis, which are countries that only have import flows and zero exports; (3) regions that import large flows but also export almost equally large flows - countries in this region act as trading hubs; (4) countries that have limited trade overall either because of self-sufficiency or small production and demand, which lie in the bottom-left of the chart.

**FIGURE 3.17. Volumes of hydrogen export and import for regions around the world in 2050 with *optimistic* technology assumptions**




Note: Import and export flows use a logarithmic function to put the different orders of magnitude on a similar scale. This makes both axes dimensionless, and this could be interpreted as an index rather than as energy flows. The export index is the $LOG_{10}$ of the exported flow in PJ/year, and the import index is the $LOG_{10}$ of the imported flow in PJ/year.

Countries follow a different pattern than in Figure 3.16. For example, in the area of exporters (points on the Y-axis), Australia, Chile and North Africa appear as the largest exporters and Saudi Arabia and the United States also appear to be large exporters. However, when the export flows for these two countries are compared with demand, the amount of exports is relatively small (14% and 11%, respectively). In the area of trading hubs, net exports from Spain are almost double its demand, but total exports are three times larger, with it acting as a transit country between the low-cost green hydrogen in North Africa and the rest of Europe through hydrogen pipelines. This is the same for Italy, which imports almost five times the equivalent of its annual demand and exports even more when combined with its renewable hydrogen production.

Among importing regions, Japan and the Republic of Korea are an expected result in this category since they are islands with limited generation potential. However, the *Rest of Europe* region could act as a transit region between eastern or southern partners in Europe and the northwest of Europe through pipelines, but this does not arise as a cost-optimal pathway in the solution.

In the area of limited trade, there are two distinct examples. Canada has a market size of 9 Mt/year by 2050, and it satisfies all this with domestic supply. It does not need to import any hydrogen from the United States (low transport cost), but its production is relatively expensive compared with other exporting markets. A similar situation takes place in sub-Saharan Africa. The demand reaches about 6 Mt/year by 2050 and most of this is satisfied with domestic production. In spite of having the largest renewable potential in the world and high-quality resources, this region has three challenges. First, the cost of capital today is relatively high, with multiple countries[26] having a WACC higher than 10% for utility-scale PV and the average for the region being 8.5%. Second, the renewable installed capacity in the region[27] was only 11 GW by the end of 2020. Thus, the renewable industry is not yet at the scale needed to establish an export market, especially considering that half the people living in sub-Saharan Africa did not yet have access to electricity in 2020. The priority should be to use electricity to give access to 100% of the population and productive activities, before (or in parallel with) considering exporting it. The average renewable share of the generation is relatively high (67%), but any renewable capacity should be first used to decarbonise the rest of the power system and extend access. Third, the prospective markets for exports from this region have good-quality resources closer: Europe is closer to North Africa, and Asian countries are closer to Australia and the Middle East.

Outside the four areas in Figure 3.17, there are other countries that do not follow the same import-export trend. For instance, Argentina is a net importer given the high cost of capital, but it is also a transit country (between Brazil and Chile). This is also the case for Germany, Japan, the Republic of Korea, the United Kingdom and the rest of Europe, but because of high demand and limited and lower quality resources compared with those of perspective hydrogen exporters.

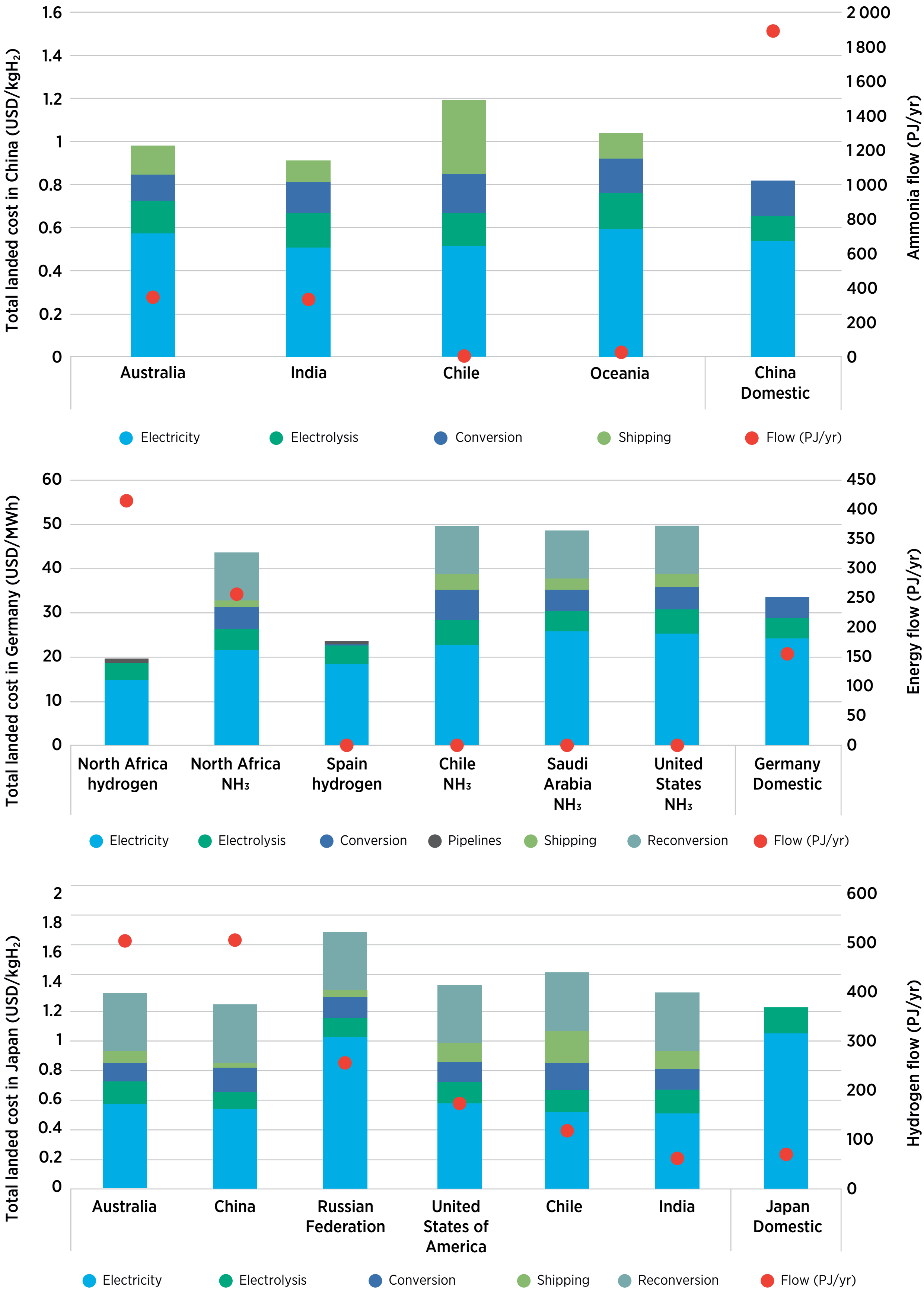
## 3.6 Cost impact of diversifying import mix

A few countries, namely China, Germany, Japan and the Republic of Korea, are relatively large hydrogen importers. The latter three because of limited land availability and expensive resources (see Figure 3.3); China satisfies a relatively small (10%) share of the ammonia demand with imports, but this represents a large flow given that Chinese ammonia demand is almost a quarter of the global total. Figure 3.18 shows the range of exporters supplying these regions, the landed cost of hydrogen or ammonia, and the cost contributors to this landed cost.

[26] *Ethiopia, Ghana, Kenya and Uganda.*

[27] *The countries included are Burkina Faso, Ethiopia, Ghana, Kenya, Mauritius, Namibia, Rwanda, Senegal, and Uganda.*

**FIGURE 3.18. Landed cost breakdown for regions exporting to China, Germany and Japan**




Note: Germany imports both hydrogen (pipelines) and ammonia (shipping), so costs are expressed per MWh delivered to make the comparison among pathways.

For Japan, a challenge is that the renewable potential is relatively small compared with the total demand (see Figure 3.3). The potential for solar PV and onshore wind together is about 750 TWh, while electricity demand alone is expected to be about 1250 TWh by 2050. This means the scarce renewable potential is used to satisfy the domestic electricity demand, and there is almost none left for hydrogen production. Furthermore, the resource quality is relatively poor, with all the PV potential being in the region of 1000-1200 hours a year of full-load operating hours. This results in a relatively high production cost of almost USD 1.2/kg$H_2$, which is nearly 80% higher than the hydrogen production cost in Australia. Only 3% of the domestic hydrogen demand is satisfied with domestic resources. Japan has ammonia demand for power generation, but most of the ammonia imported (1.8 EJ/year compared with 2.6 EJ/year of hydrogen demand) is for use as a hydrogen carrier. This makes the reconversion to hydrogen necessary, adding almost USD 0.4/kg$H_2$ to the hydrogen cost, which is significant when the landed ammonia cost is about USD 1/kg$H_2$. Among green hydrogen suppliers to Japan, the cost ranges from USD 1.25/kg$H_2$ to USD 1.45/kg$H_2$. That means the cost premium for changing suppliers with very different profiles (*e.g.* Australia, China) is relatively small (up to 16%). This is the case in 2050, where all the renewable and hydrogen costs have come down, but it might be different during the transition phase. It will also be largely influenced by how the WACC evolves over time (see Section 3.8). Domestic ammonia production in Japan has also been declining in the last decade. Production in 2020 was roughly a quarter lower than in 2012. Going forward, the share of domestic production will be influenced by the trade-off between economic factors, energy security and industrial competitiveness. It is more cost-effective to produce ammonia (or even fertilisers) abroad and import it, but this would lead to dependence on imports for this commodity and a reduction of industrial activity. Today, the feedstock used for ammonia production is imported anyway, so it is a matter of the point in the value chain where the energy or commodity is imported, the profit margins, and the location of the industrial activity.

China is a contrasting case. It satisfies all its hydrogen demand domestically (even exporting some of the hydrogen to Japan), and it only imports ammonia to satisfy 10% of its ammonia demand and does not have any ammonia cracking capacity. The domestic potential is relatively large: PV resources with a capacity factor of over 17% are almost 12 times the total electricity demand, including hydrogen and ammonia. The capital costs and WACC are also relatively low, which leads to cheap domestic ammonia production, and the only imports are from Australia and India. Like Japan, the cost premium for changing suppliers is relatively small: 6% for changing from India to Australia.

Germany is somewhere between China and Japan. It has relatively poor resources, and most of the PV potential has a capacity factor below 14% and most of the onshore potential less than 30% (see Figure 3.3). It also has relatively low renewables potential – only about 65% higher than electricity, hydrogen and ammonia demand combined. Consequently, Germany satisfies almost 70% of its hydrogen demand and all its ammonia demand with imports. Germany, unlike Japan, has the flexibility to use existing natural gas pipelines, which also provides greater flexibility to satisfy the demand. The transport from North Africa to Germany adds only about USD 0.2/kg$H_2$, since the route is mostly based on existing natural gas pipelines, but the difference in renewable resource quality is such that the delivered cost is still lower than domestic hydrogen production. For ammonia, the shipping cost is even smaller than the transport cost by pipeline, and since ammonia is directly used (*i.e.* without the need for reconversion), ammonia import is also more attractive. This is the result of using a cost optimisation approach without any additional constraints. This is only the first step in defining the global trade outlook, since it needs to be adjusted for the soft factors described in Section 1.4, and it is unlikely that after such considerations imports will predominantly come from a single country, especially after the energy dependency issues highlighted by events in Ukraine in early 2022.

The case for ammonia imports is stronger since there is no cost penalty for reconversion and the only trade-off is between shipping cost and difference in production cost. For hydrogen, the trade-off is more difficult to overcome since it has conversion and reconversion costs on top of shipping costs, which makes domestic hydrogen production costs lower even in a case like Japan (*i.e.* low-quality resources), and imports become attractive just because of the limited potential rather than the cost.

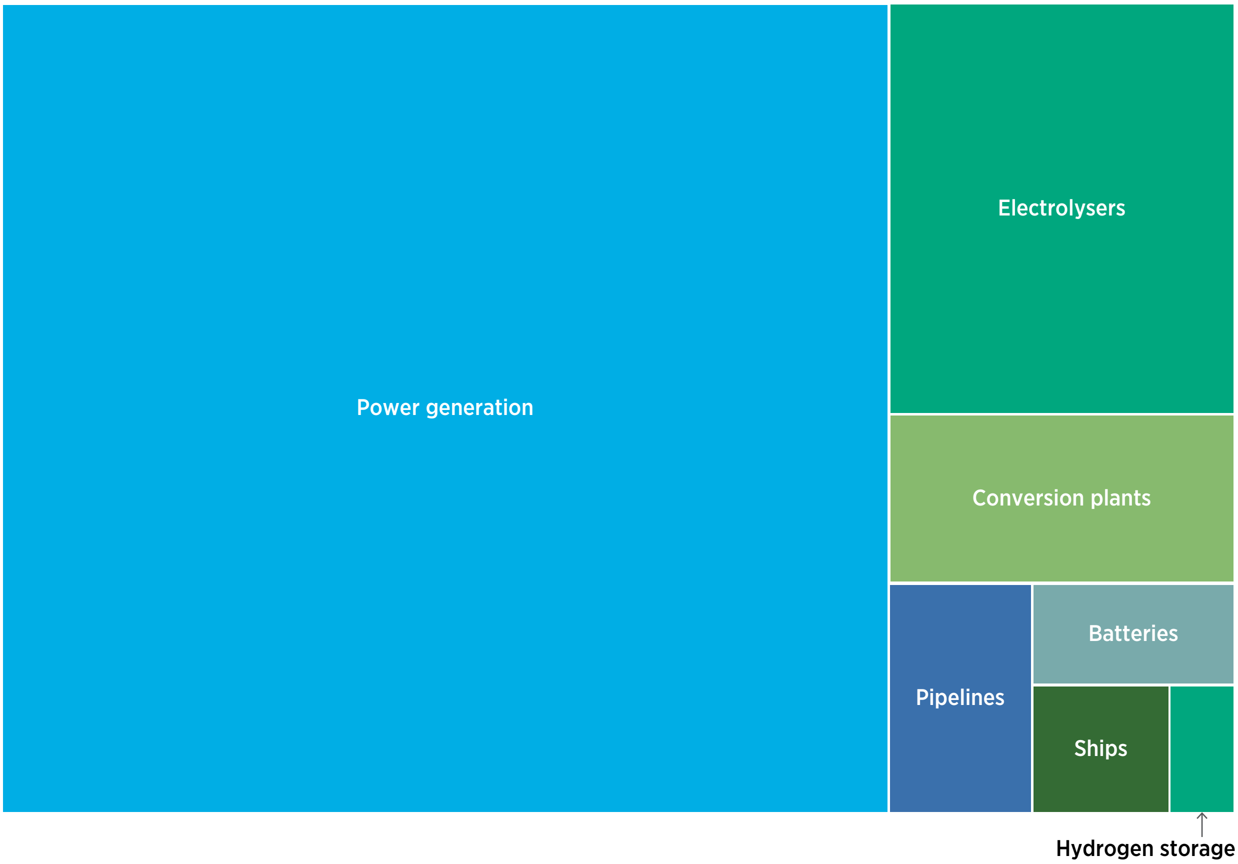
## 3.7 Investment needs to develop hydrogen infrastructure

To be able to trade 36% of the global hydrogen flow, a total investment of about USD 4 trillion would be needed. This includes the entire supply chain, from electricity generation, to electrolysis, all the way to electricity and hydrogen storage, conversion plants, pipelines, ships and reconversion plants (see Figure 3.19). This investment is associated with 10.3 TW of renewable capacity (mostly PV), 4.4 TW of electrolysis and 1.6 TWh of batteries (with a two-hour capacity).

An advantage of this system is its low operational costs and low price volatility, since most of the cost is the upfront investment. In terms of investment breakdown, almost three-quarters of the total is in power generation, mostly PV and, to a much lesser extent, wind. To put this value into perspective, previous IRENA analysis has identified that an investment of USD 131 trillion is needed from now until 2050 to align the current energy system with a 1.5°C pathway (IRENA, 2021d). Some other references are that the global investment in energy is about USD 1.8 trillion, out of which about USD 0.55 trillion is for infrastructure (IEA, 2021d), and the global energy spending in oil products was about USD 2.6 trillion, all of these figures in 2020. Another reference is the current market value of annual hydrogen production, which is about USD 175 billion,[28] potentially growing to USD 600 billion (Morgan Stanley, 2021). Thus, USD 4 trillion is relatively small compared with the investment in the wider energy system, also considering that hydrogen would represent about 12% of final energy demand. This estimate, however, is only the lower bound since the model used is greenfield, meaning it assumes all the infrastructure is new, and it uses the 2050 costs to estimate the total investment. In reality, investment will happen over time, with part of the capacity being deployed at higher costs. The average will, however, tend to be defined by the lowest costs when the largest deployment takes place. Another reference for investment across the entire value chain (including storage, downstream use and fuel cells, which are outside the scope of this study) is from Goldman Sachs and estimates that the value chains of green hydrogen could become a USD 11.7 trillion investment opportunity in the next 30 years.

[28] *Each year around 87 Mt of pure hydrogen is produced globally, of which 95% is grey hydrogen, made from unabated natural gas or coal. The cost of producing grey hydrogen is currently between USD 0.70/kg and USD 2.20/kg, largely depending on the price of natural gas or coal (average of USD 1.45/kg assumed).*

**FIGURE 3.19. Investment needs for global hydrogen production and trade infrastructure to reach almost USD 4 trillion between 2020 and 2050**




Note: Area is proportional to the investment in the respective part of the value chain, with the total area adding up to USD 3 960 billion. The cost of conversion plants includes storage and terminals costs and refers to both conversion and reconversion from or to hydrogen. The results are from this analysis.

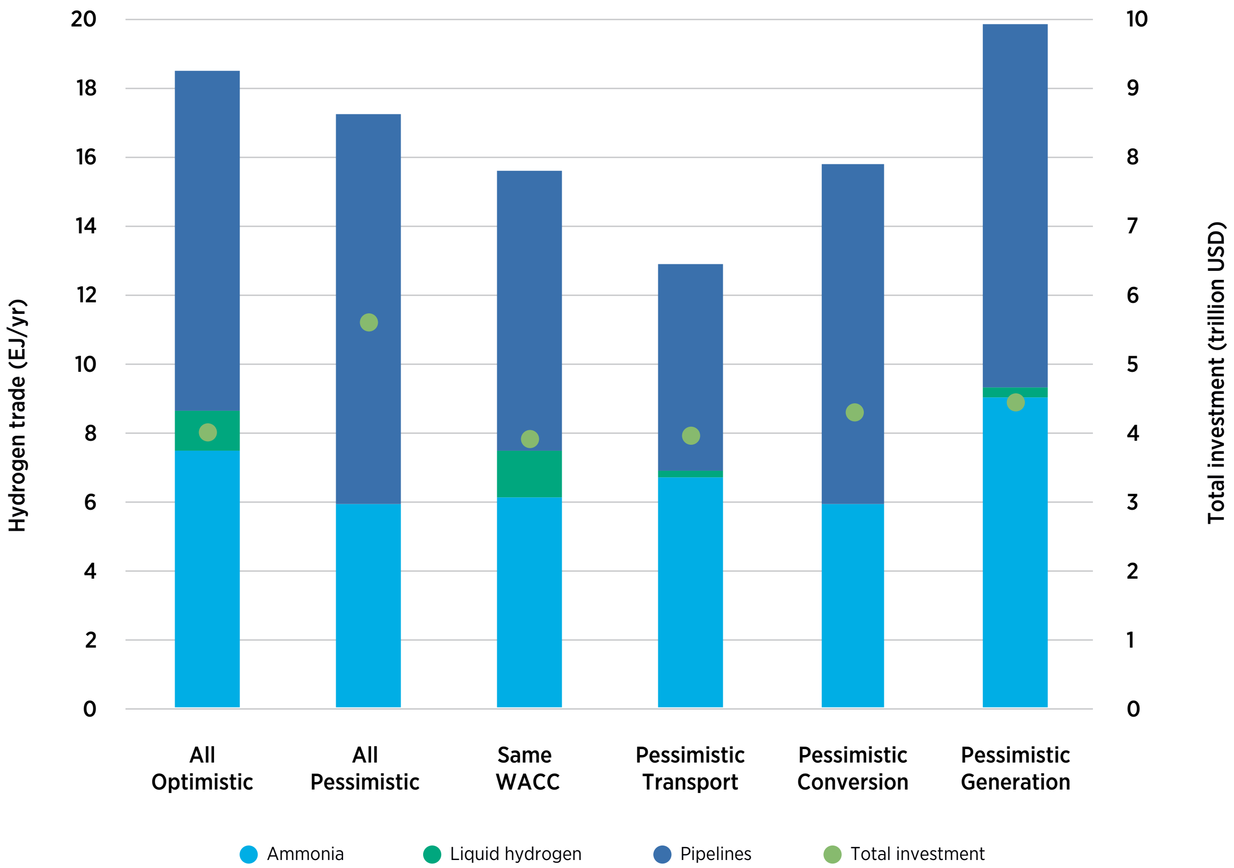
The share of investment in the international trading infrastructure and conversion and reconversion facilities is actually relatively small, at just over 11% of the total. This reflects that with both hydrogen pipelines and ammonia shipping, the transport cost is relatively small compared with the total delivered cost, and most of the cost is from production (dominated by renewable electricity input). Domestic and "in-region" investments for the 34 countries and region considered in the analysis were excluded.

Ammonia also has the advantage of requiring the lowest total amount of capital for a fixed hydrogen capacity, about 35% lower than the total investment needed for LOHC and 65% lower than liquid hydrogen. Liquid hydrogen has higher costs for conversion, storage and ships due to the cryogenic conditions required, while LOHC requires double the number of ships (due to a low hydrogen content by weight), and has an additional cost penalty due to the carrier cost (ship inventory and losses). For liquid hydrogen, the investment at the importing terminal is the lowest, which has the benefit of simpler design and fewer changes needed compared with the other two pathways but the disadvantage that the ships are the most expensive (due to the cryogenic requirements), and any increase in transport distance results in more ships being needed to satisfy demand.

## 3.8 Alternative scenarios and sensitivity of results to pessimistic assumptions

The trade towards 2050 will largely depend on the evolution of some key parameters from now until then; especially important are (1) electricity cost, since it is the major contributor to hydrogen production cost, and (2) shipping cost, since it would make it more expensive to move hydrogen from one country to another. The electricity cost is mainly dependent on the capital cost and the WACC[29] (see Figure 3.2) since the quality of the resource will not change over time. Hence, these three parameters are varied to understand how much the hydrogen trade outlook changes and what it means for some specific countries. Figure 3.20 shows how the global trade can change with different assumptions, followed by what it can mean for specific regions.

**FIGURE 3.20. Global hydrogen trade in 2050 by technology pathway and total investment for various sensitivities**




Note: *Same WACC* refers to a scenario where all the countries have the same risk profile, resulting in the same WACC (5%) across all countries. *Pessimistic transport* and *pessimistic conversion* use roughly double the costs for these steps and consider the rest of the values with an *optimistic* outlook (*i.e.* single change). *Pessimistic generation* considers higher capital expenditure for photovoltaic by about 20% and for onshore wind by about 10%. *All pessimistic* combines the worst case for all parameters. WACC = weighted average cost of capital.

[29] *For electrolysers connected to the grid (outside the scope of this study), the connection costs, taxies and levies can also be a significant share of the cost.*

## Global perspective

In general terms, global trade remains significant across scenarios, but deviations of up to 30% take place for some scenarios. In a future where all the countries have the same WACC across regions, eliminating some of the differences in electricity production cost between regions (and therefore decreasing the incentive for trade) reduces global trade by 15% to 15.5 EJ/year. Ammonia shipping is reduced by almost 19%, reaching only 6 EJ/year (versus 7.4 EJ/year in the *optimistic* scenario). Similarly, the incentive for trading by pipelines is also smaller and decreases to 8.1 EJ/year (versus 9.8 EJ/year in the *optimistic* scenario). A similar reduction of 15% takes place in the scenario where conversion plants are more expensive. The main reason for decrease in trade in this scenario is that reconversion to hydrogen becomes more energy intensive due to higher energy consumption with a more expensive energy source. This leads to hydrogen reconversion (from ammonia since there is no LOHC) being slashed by more than 90%, from 2.4 Mt/year in the *optimistic* scenario to just 0.2 Mt/year in the *pessimistic conversion* scenario. The trade is not affected as much, given that only 20% of the ammonia is used as a hydrogen carrier and most of the ammonia produced is used directly as a compound rather than being reconverted to hydrogen. This scenario also considers a relatively high energy penalty for liquefaction, which makes it disappear from the optimal solution. Even with a low electricity cost from exporting regions, the energy consumption is too high and makes this pathway unattractive.

The worst case for trade is when the transport cost is at its most expensive. Doubling the transport cost increases the landed cost and makes domestic production more attractive. Overall trade decreases by almost 30% to 12.8 EJ/year. The largest reduction, of almost 40%, is for hydrogen pipelines, with a 10% decrease for ammonia shipping. Like other scenarios, liquid hydrogen use is not robust; it disappears once the transport cost is higher due to higher boil-off losses during transport.

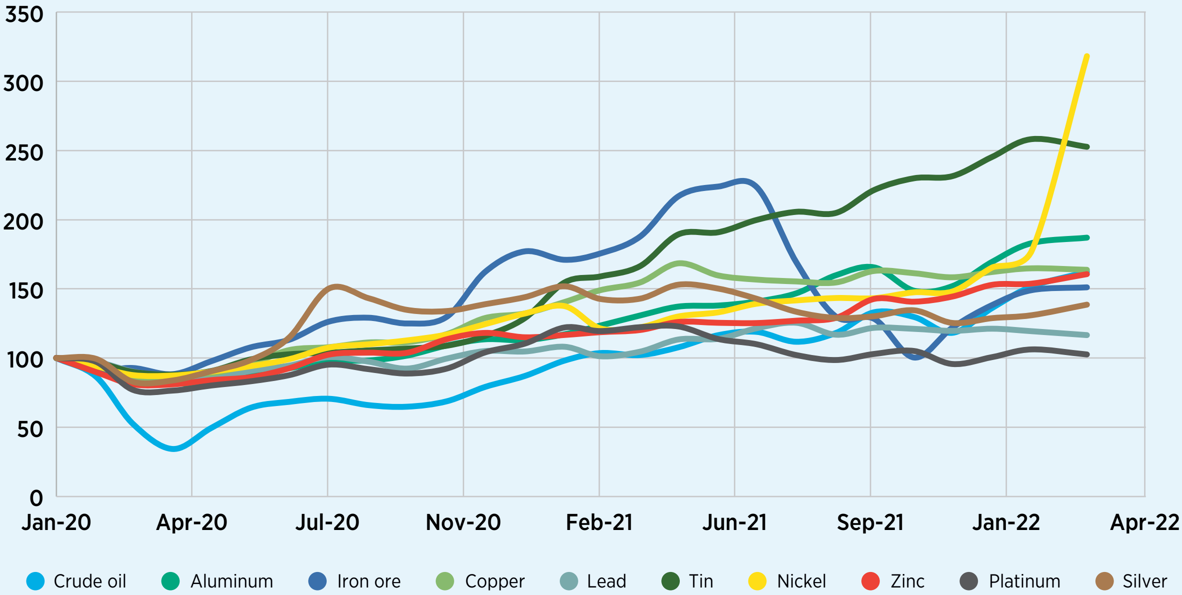
One scenario where trade increases is when generation is more costly than the reference case. This would still be lower than current costs, because renewables are already cost competitive today and deployment will continue just by virtue of their being the most profitable option, without incentives. Two factors that could slow down this trend are inflation and increase in commodity prices (see Box 3.1). With relatively small increases of 10-20% in onshore wind and PV, domestic hydrogen production for countries that do not have good resources becomes more expensive. This makes import more attractive, with hydrogen trade increasing by about 8% to 19.8 EJ/year.

**Box 3.1. Effect of higher capital costs for renewables and electrolysers on hydrogen trade in 2050**

Since the series of lockdowns due to COVID-19 in March/April 2020, commodity prices have increased significantly, reaching multi-year or all-time highs. Iron ore prices reached an all-time high in June 2021, nearly tripling their level from two years before. Aluminium prices surpassed their 2008 record, reaching almost USD 3 800/t in March 2022. The price of copper, one of the key components of renewable technologies and transmission grids, has increased by almost 80% in the last two years (see Figure 3.21). At the same time, the United States of America and Europe have experienced a recent increase in inflation, reaching 8% in the United States in February 2022 and 5% in Europe in December 2021. While these are temporary trends that do not have any influence on 2050 values, they highlight the effect that a sudden increase in material demand (*e.g.* from an accelerated pace of technology deployment) can have on costs, potentially impacting capital costs.

**Box 3.1. (Continued)**

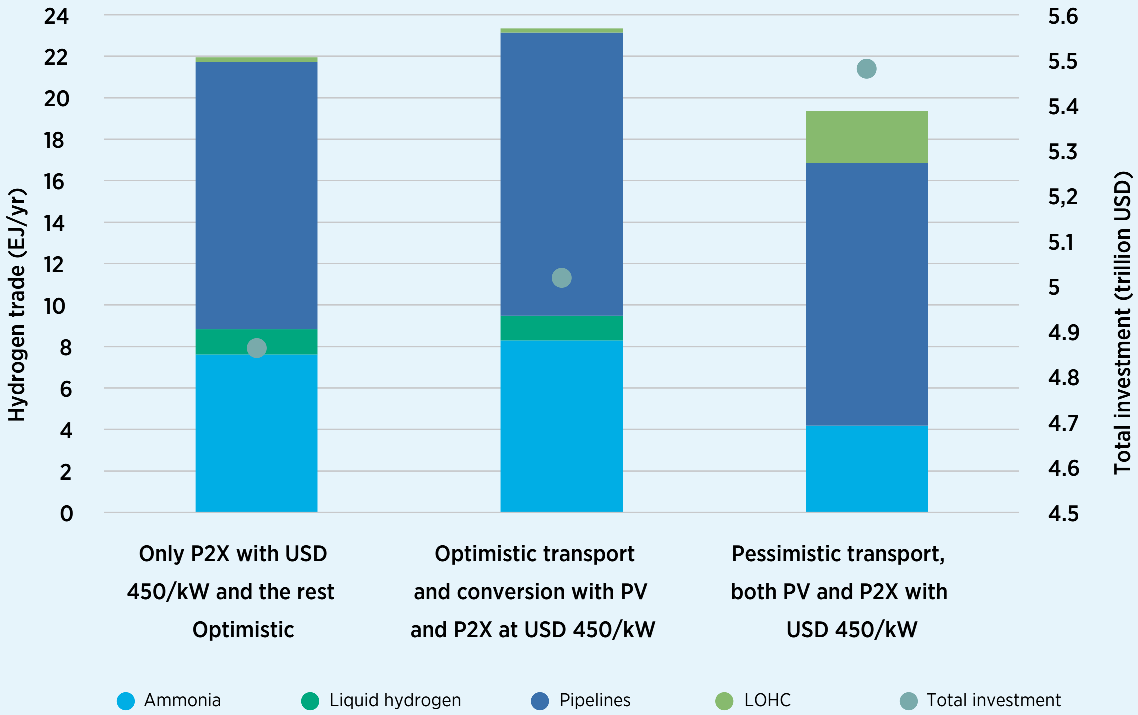
**FIGURE 3.21. Commodity price trends from beginning of 2020 until Q1 2022**




Source: World Bank (2022).

Prolonged periods of higher commodity prices could lead to higher capital costs than anticipated through conventional learning rates. Figure 3.22 shows the global hydrogen trade and total investment for various scenarios in which the capital expenditure for solar PV and the electrolyser is USD 450/kW in 2050.

**FIGURE 3.22. Global hydrogen trade in 2050 by technology pathway and total investment for scenarios with higher CAPEX for PV and the electrolyser**




Note: CAPEX = capital expenditure; LOHC = liquid organic hydrogen carrier; P2X = Power-to-X; PV = photovoltaic.

**Box 3.1. (Continued)**

In the scenario with *optimistic* assumptions for all components, except for the electrolyser CAPEX, global trade increases to 22 EJ/year, about 20% higher than in the *all optimistic* scenario. In this scenario, all the hydrogen production costs are shifted upwards, increasing the global average by almost 30% to above USD 0.9/kg$H_2$. Countries with high labour and installation costs for renewables (*e.g.* Australia, Canada, Japan, the United States) are also assumed to have the highest electrolyser costs. Since CAPEX is higher in this scenario, cost differentials between regions are wider, increasing the incentives for trade. More expensive electrolysers also mean a higher investment by over a factor of two for the electrolysers and by almost 20% for the entire system. This also translates into lower electrolysis capacity (of about 3.3 TW, producing about 44.1 EJ/year), meaning other production routes (fossil based) become more cost-effective for a wider range of countries. The production cost in Australia increases by almost 40%, driven by a higher than average CAPEX for the electrolyser. This results in a drastic reduction of exports to Japan, being displaced by other low-cost countries such as China and even countries further away like Chile. China also benefits from having one of the lowest CAPEX, reaching a larger market share of the shrinking ammonia market.

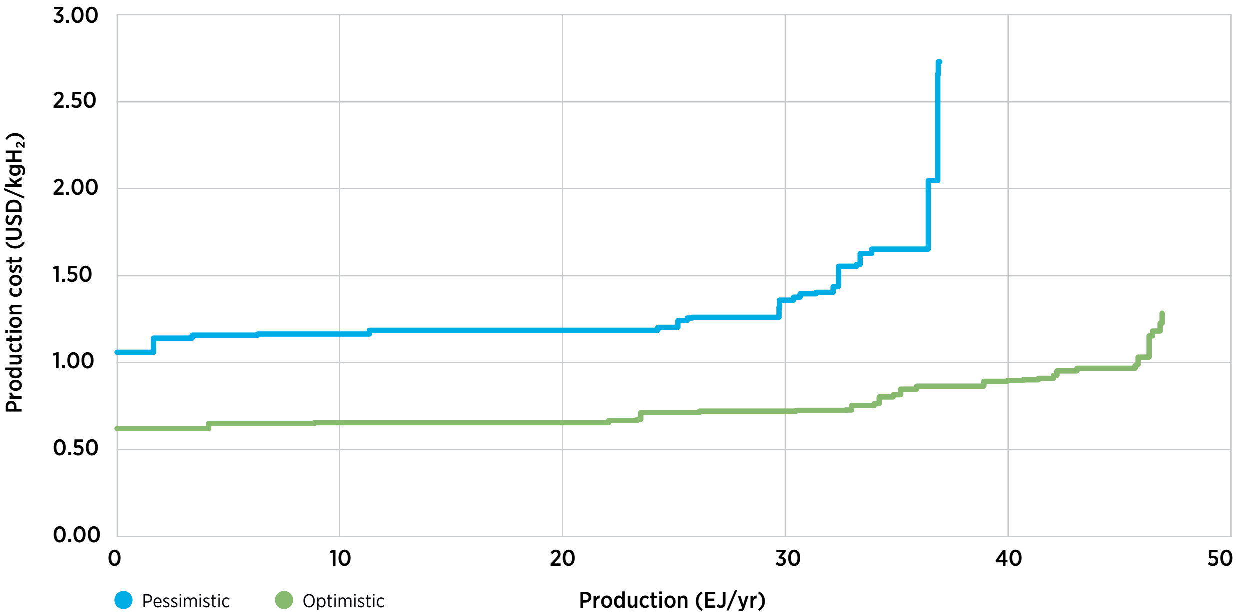
For the scenario where both solar PV and the electrolyser are higher (USD 450/kW), the effects are similar to the previous scenario, just more pronounced. Electricity becomes more expensive, leading to a higher global hydrogen production cost average, reaching USD 1.1/kg$H_2$. Solar PV is still the most attractive renewable technology, but offshore wind becomes more attractive for some regions, reaching about 20% of the global electricity supply. The cheapest hydrogen is now from China, where the quality of the resources is not as good as in other locations (*e.g.* Chile), but the lower capital cost is accentuated in this scenario, leading to the lowest cost. The global investment in electricity generation increases by about 15% (versus the *all optimistic* scenario), and the total investment reaches levels above USD 5 trillion. Overall trade increases even further to reach 23.3 EJ/year, with similar shares for ammonia shipping and pipelines. Since renewable hydrogen is more expensive, its global production is reduced further to 37.7 EJ/year, requiring 2.8 TW of electrolysis. Hydrogen production in Europe becomes more expensive, reducing domestic renewable hydrogen production by almost two-thirds (compared with the *all optimistic* scenario). This is compensated by further production from North Africa, which has, on average, lower capital costs than Europe.

The last scenario is the one with the highest costs and includes *pessimistic* assumptions for the entire value chain and USD 450/kW for the CAPEX of solar PV and the electrolyser. In this scenario, both the production and the transport become more expensive. This is the worst scenario for importing countries, which are left to choose between two expensive choices. The global average production cost is almost USD 1.3/kg$H_2$, with Germany, Japan and the Republic of Korea all being above average at 1.7, 3 and 2.6 USD/kg$H_2$, respectively. The higher transport cost (compared with the scenario discussed above) reduces the global trade to 19.3 EJ/year, but this is still higher than the *all optimistic* scenario of 18.4 EJ/year. The cost for generation and the total cost are the highest across all scenarios, reaching a total investment of about USD 5.5 trillion.

When all the costs are the highest, in the *all pessimistic* scenario, opposite factors almost cancel each other out. Domestic generation is more expensive given the higher costs for PV and onshore wind, but import is also more expensive due to higher transport cost and reconversion to hydrogen. The reconversion cost can be reduced by using ammonia directly, but the other two factors lead to higher costs with either option chosen (import or domestic). This means that the global hydrogen production cost average in the *all pessimistic* scenario is almost 50% higher than in the *optimistic* scenario. The largest increase is for countries that need to import due to their limited potential. Germany, Japan and the Republic of Korea would have a higher cost of hydrogen by 64%, 112% and 128%, respectively. Countries that have a high WACC today would also be impacted negatively. The production cost in Colombia and Latin America would increase by almost 90%, and countries in the Middle East that have a high WACC today, like the Islamic Republic of Iran, Iraq and Yemen, would actually import since they are close to other markets that would have a much better production cost (driven by WACC differentials) and can be connected with pipelines (*e.g.* Saudi Arabia). Other countries in the Middle East, like Israel, Kuwait, Jordan and the United Arab Emirates, could become attractive for hydrogen production given their low WACC today.

The change in assumptions has a large impact not only for the flows but especially for the hydrogen production costs. Figure 3.23 shows the production curve for two contrasting scenarios: (1) an *optimistic* scenario, meant to establish a lower bound for the costs and to understand what could happen in an ideal future where all the costs have come down, and (2) a *pessimistic* scenario, which explores the impact that higher costs (high considering the year analysed is 2050, but still lower levels than today) could have on production and trade.

**FIGURE 3.23. Green hydrogen supply cost curve for the *optimistic* and *pessimistic* scenarios in 2050**



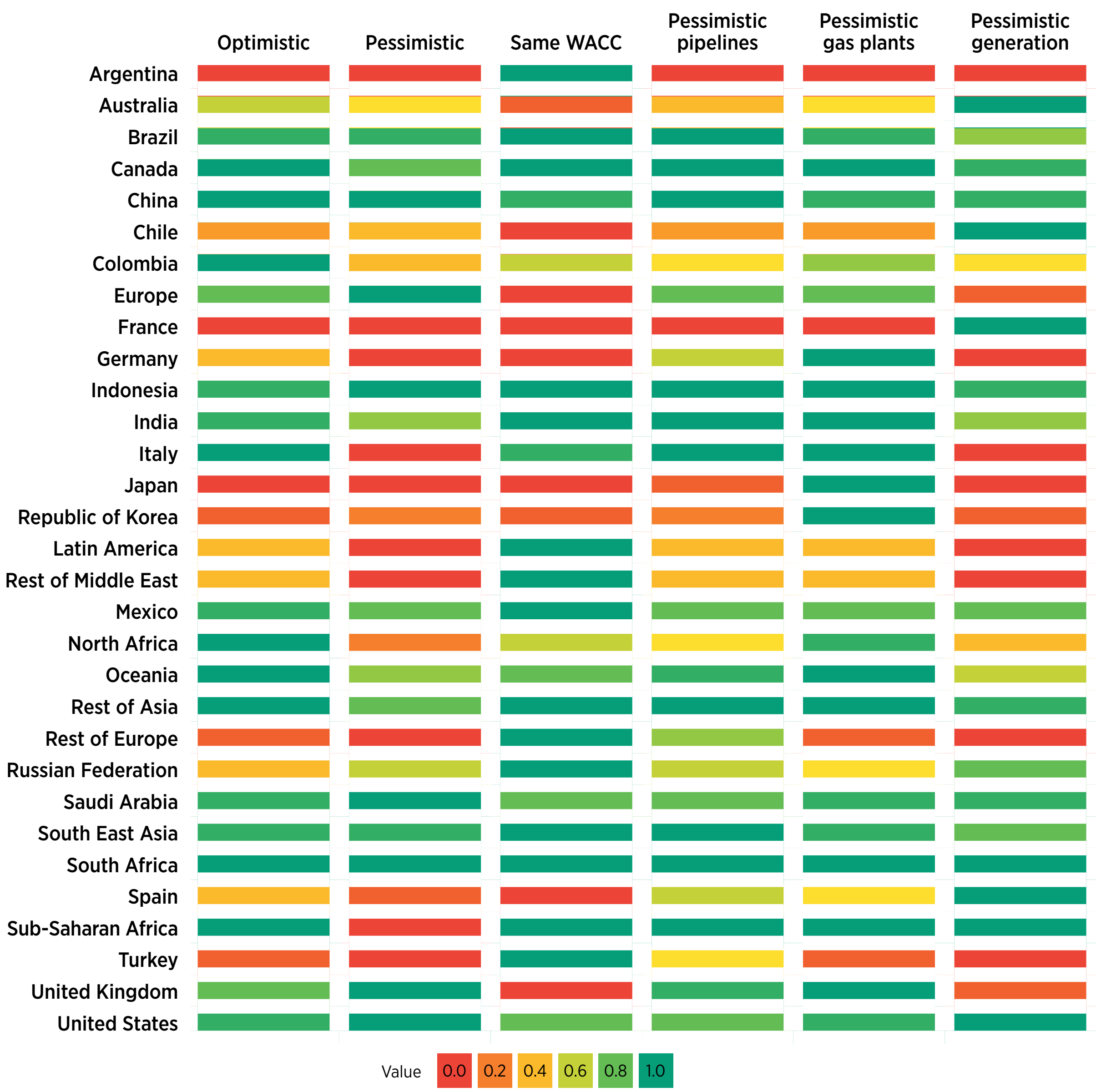

Note: *Optimistic* capital expenditure (CAPEX) assumptions for 2050: photovoltaic (PV): USD 225-455/kW; onshore wind: USD 700-1070/kW; offshore wind: USD 1275-1745/kW; electrolyser: USD 130/kW; weighted average cost of capital (WACC) as per 2020 values without technology risks across regions. *Pessimistic* CAPEX assumptions for 2050: PV: USD 270-550/kW; onshore wind: USD 775-1190/kW; offshore wind: USD 1350-1900/kW; electrolyser: USD 325/kW; WACC as per 2020 values.

The future can also lead to a less globally co-ordinated approach, less transferring of lessons learned, less replication and globalisation, all of which lead to higher costs overall. Under a *pessimistic* scenario, it is assumed that total deployment will be lower than in a 1.5°C scenario and with lower learning rates. This would lead to 20% more expensive utility-scale PV, 10% more expensive onshore wind and more than 2.5 times the capital cost of the electrolyser (which has the smallest deployment today and the largest uncertainty). This would still lead to low production costs of USD 1.1-1.2/kg$H_2$ for the best locations in the world, compared with a range of USD 3-6/kg$H_2$ estimated for 2021. Many countries would still have the ability to produce hydrogen at less than USD 1.5/kg$H_2$ (see Figure 3.23). The most important difference is that the amount of hydrogen that can be produced at such low cost is much more limited. The potential at this cost level of USD 1.5/kg$H_2$ (which is competitive with fossil-based hydrogen with carbon capture, utilisation and storage for gas prices of USD 5-10 per gigajoule) would only be about 33 EJ/year. This is about three times the current pure hydrogen production but would be short of the 2050 demand (without power) of 50 EJ/year. To satisfy the rest of the demand, more expensive renewable resources would need to be used.

## Regional perspective

While the global outlook remains roughly stable across scenarios, the outcome for specific regions can drastically change depending on the scenario. Figure 3.24 shows the renewable hydrogen production for each region across the different scenarios evaluated. Values are expressed relative to the scenarios with the highest production (*i.e.* a value of 1 represents the scenario with the highest production, and an intermediate value between 0 and 1 means that the region has a reduced production for that scenario).

**FIGURE 3.24. Hydrogen production by country across scenarios expressed relative to the scenario with the highest production**



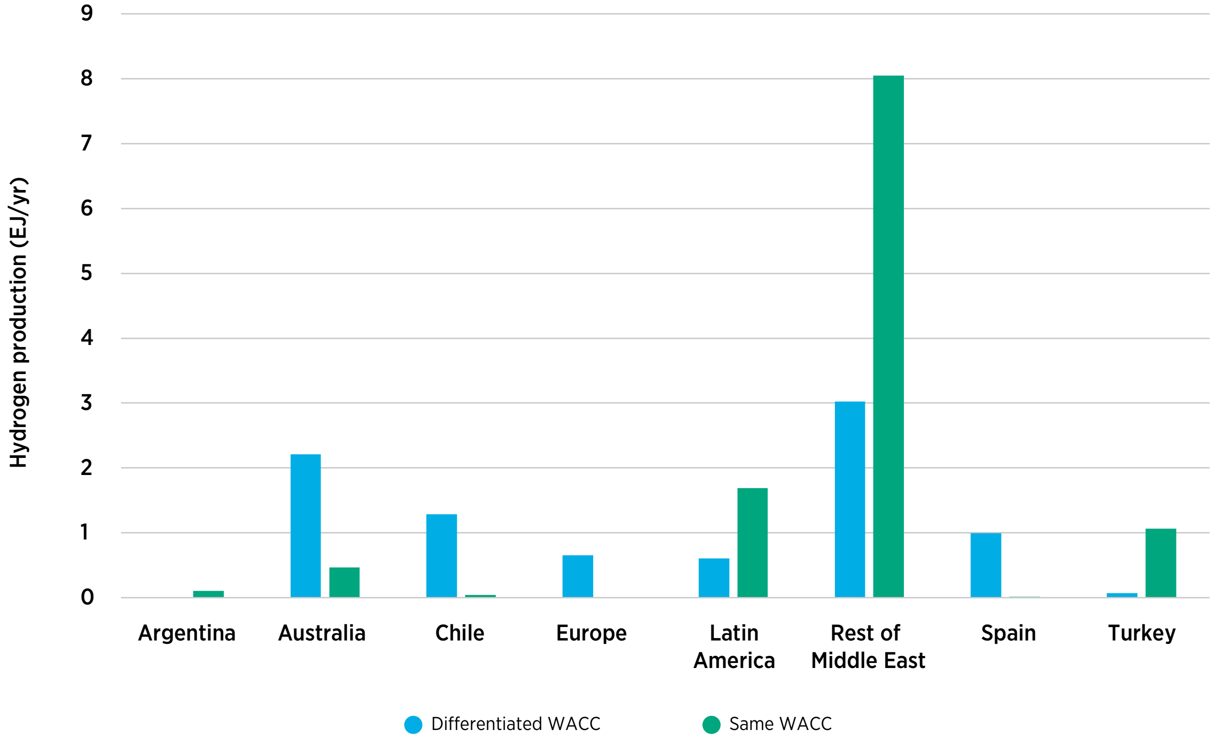

Note: Values are based on hydrogen production for various scenarios and have been normalised to the scenario with the highest production for a specific region. WACC = weighted average cost of capital.

One of the largest uncertainties is how the WACC for different countries will evolve over time. For instance, from the early days of PV in the 2000s in Germany, the costs of equity and debt (before tax) were 9.3% and 5.5%, respectively, decreasing to 4.8% and 1.5% in 2017 (Egli, Steffen and Schmidt, 2018). Towards 2050, there will be trends of industrial development, which means that several countries will have a renewable industry established, and a trend towards urbanisation, democracy and digitalisation, which may affect the risk profile of a specific country and therefore the WACC. The two extremes are tested in this study: one where the risk profiles and WACC remain the same as they are today (Egli, Steffen and Schmidt, 2019) and one where all the countries have the same WACC (Bogdanov *et al.*, 2019) and the production cost differentials are driven by the quality of the resource and the capital cost. Some of the factors that can contribute to equalisation of WACC, specifically for hydrogen, are technology transfer through joint projects or co-operation agreements, capacity building, and the use of international financing instruments. However, WACC is largely dependent on factors beyond hydrogen, such as industrial development, experience of financial institutions and status of the renewable energy industry, which ultimately affect the risk perception and cost of debt and equity used for the WACC calculation.

For the *same WACC* scenario, hydrogen production in Australia is slashed by 80% and in Chile by almost 90% (see Figure 3.25). The advantage that these countries have today with a relatively low WACC (3.7-4.6% and 5.2%, respectively), in addition to excellent resources,[30] would disappear in a world where all countries can access the same favourable financing conditions and reach those low WACC levels. In this case, the difference in resource quality alone is not enough to justify the long-distance transport to reach the potential importers. On the flip side, some of the regions that would benefit from this change would be the ones that have good renewable resources but higher cost of capital today. Thus, the Middle East and North Africa (excluding Saudi Arabia) would nearly triple its hydrogen production, becoming a net exporter with almost 1 EJ/year of production, from a net importer in the reference scenario; a similar increase (to reach 1.7 EJ/year) would occur for Latin America and Turkey. This happens because these regions have high WACC today, which might prevent large green hydrogen deployment if the WACC continues at this level but unlocks new potential if a low cost of capital can be achieved. With a lower cost in North Africa and sub-Saharan Africa, Spain goes from a net exporter and trading through pipelines with the rest of Europe to a trading hub between North Africa (which has better resources and would have a lower cost in this scenario) and the rest of Europe, drastically reducing its production. A share of the hydrogen might come from on-grid electrolysers (outside the scope of this study), which should be largely decarbonised well before 2050. In this case, a factor that could accentuate or reduce the effects of WACC differential are the connection costs, taxes and levies included in the electricity price.

[30] *This conclusion is only based on economic factors from Figure 3.1 and does not include the full range of factors from Figure 1.8.*

**FIGURE 3.25. WACC effect on hydrogen production for selected export-oriented countries**




Note: WACC = weighted average cost of capital.

Oil-exporting countries can be major players in green hydrogen, provided they get access to abundant low-cost capital for investments in renewables, electrolysis and hydrogen infrastructure, which today is the case for only a few of them. In this case, the Middle East and Latin America can compete on hydrogen exports with leading renewable electricity producers that are considering exporting hydrogen as a means to further monetise their renewable potential. For some of the incumbent oil exporters, green hydrogen represents an opportunity to offset some of the fossil fuel export losses. For others, it is an opportunity to export renewable electricity by converting it to green molecules. Both the Middle East and Latin America have excellent renewable energy potential. The crucial factor will be access to large volumes of low-cost capital and the speed of execution of gigawatt-scale projects. Some countries in these regions like Israel, Kuwait, Jordan and the United Arab Emirates combine a low WACC today with an accelerated deployment of renewables in the last couple of years, putting them in a good place to develop a competitive hydrogen industry.

For the scenario with higher transport costs, the trend is similar. The largest exporters, Australia, Chile and North Africa, see their total production reduced, this time by 30%, 15% and almost 50%, respectively. Australia exports less to China and Southeast Asia. As a result, the major importers produce more hydrogen domestically, which has now become attractive. Germany, Japan and the Republic of Korea increase their domestic production by 34%, 78% and 95%, respectively, at the expense of producing up to 20% more expensive hydrogen (for Japan). Production in the rest of Europe increases almost eight times, from about 0.6 $MtH_2$/year in the *optimistic* scenario to over 5 $MtH_2$/year. For all other regions, the production costs remain roughly the same, with the global average only increasing by 2% and the main consequence being lower trade. For some countries, however, it leads to cost increase since demand stays the same, but the share of domestic hydrogen is higher, using more expensive resources to satisfy that demand. For Japan and the Republic of Korea, the hydrogen cost increase is 20% and 12%, respectively, due to the high reliance on shipping, as opposed to Europe, which can compensate with more imports by pipelines, which remain relatively cheap.

The scenario where generation is more expensive is the most detrimental for importing countries and countries with higher than average WACC. Production in Germany is reduced by more than 95% since it has relatively cheap options from neighbouring countries that are well interconnected with pipelines. The same conditions (low-cost regions as neighbours with the possibility of repurposing natural gas pipelines) lead to a similar production cut in Latin America. Production in Japan is reduced by a more modest 30% since it does not have the flexibility of pipelines. Among the countries that are favoured by such a change are Spain, which more than doubles its production to satisfy the German demand; Chile, more than tripling its production; and Australia, increasing its production by 70%, mainly driven by a higher trade with the Republic of Korea. Overall, countries with poor-quality resources suffer a higher penalty than countries with good-quality resources due to utilisation of the assets. Since this scenario combines higher CAPEX with higher WACC, the countries that are most favoured are the ones with low cost today. This also leads to a high market concentration, with the top three exporters (Australia, Chile and Spain) representing two-thirds of the market. In contrast, exports from North Africa are reduced by 60% since the high WACC it has today would prevail, but exports would remain sizeable at 1.6 EJ/year.

For the scenario where all the parts of the value chain are more expensive (*i.e. all pessimistic*), these effects cancel one another out to some extent. Places with low-quality resources suffer the most from the more expensive generation, making the domestic production more costly than the corresponding increase abroad. Transport and conversion are also more expensive. This leads to an overall reduction in trade of about 6%, but the most drastic change is for prices. Average production costs increase by about 40%, since the choice is now between expensive domestic production or expensive imports. The largest increases are for Japan and the Republic of Korea, where the production cost more than doubles and leads to Germany importing all its hydrogen since it has the advantage of possible imports by pipeline. The production cost in China increases by 80% and remains broadly self-sufficient just at a higher cost point. The cost in North Africa nearly doubles (driven by higher WACC), and overall production is slashed by almost 80%.

The countries that remain relatively stable to the changes across scenarios are mostly self-sufficient regions. Brazil, Canada, China, India, Indonesia, Mexico, the rest of Asia, South Africa and the United States maintain a production within 20% of the maximum across scenarios. These regions have enough domestic resources and can always rely on this, while a small share of trade can be attractive under some conditions. For the cases of China and the United States, both domestic resources and hydrogen, ammonia and electricity demand are relatively large compared with other countries. This results in a large share of the demand being satisfied domestically and being relatively unaffected by changes in transport cost or cost of renewable generation. Morocco and other countries in North Africa are favoured by the proximity to Europe, which has combined high demand and regions of high cost, making North Africa a favoured trading partner for Europe.

# 4 NEAR-TERM ROADMAP TO ENABLE GLOBAL TRADE

# NEAR-TERM ROADMAP TO ENABLE GLOBAL TRADE

## Highlights

Multiple dimensions need to work together, and almost simultaneously, for hydrogen trade to start. Today, there is no market where hydrogen suppliers and users can interact and where users with a higher willingness to pay can buy renewable hydrogen. An action that governments can take is to create a demand for this market by introducing policies that promote fuel shift in industry, public procurement (relevant for steel), and aggregation of demand in hydrogen valleys to drive economies of scale. Governments can also promote transparency and ensure that prices for transactions from early market participants are (anonymously) disclosed, contributing to price formation. Auctions can be used as a mechanism to contribute to competition and the most efficient use of public support, while conditions and prices from bids can be used for market development.

Market development goes closely together with certification to enable tracking of renewable hydrogen, to demonstrate to customers the lower emissions from its production, and to differentiate it from other carbon-intensive hydrogen. Many ongoing initiatives aim to develop a certification scheme, but most of these focus on the production step and greenhouse gas emissions. To make them suitable for hydrogen trade, the (re)conversion process and transport need to be covered as well. To be able to link hydrogen production with demand and the full climate mitigation benefits that hydrogen can offer, the certification scheme also needs to be linked with derivatives (commodities). These schemes need to be consistent in their methodology and approach to facilitate transfer across borders and must focus on quantitative information rather than labels.

Infrastructure is needed to connect all the possible market players and to increase the size of the market, the liquidity and the efficiency, ultimately leading to competition and lower prices. Some necessary conditions for this infrastructure are transparency, non-discriminatory third-party access (all the market participants being able to use infrastructure), unbundling (separate activities and preventing monopolies), and – most importantly – a progressive, adaptive regulatory approach that responds to market developments and takes into account the limited existing infrastructure.

Global hydrogen trade will not happen at the current cost levels, and costs across the entire value chain need to decrease. IRENA has previously explored multiple incentives to reduce production costs, including direct financial support in the form of grants or loans, fiscal incentives, or measures tackling the high contribution of the electricity cost, like feed-in premiums and exemptions from grid fees. Scaling up both the electrolysers and the manufacturing capacity and improving electrolyser performance can lead to cost competitiveness within the coming decade. Similar incentives can be used for downstream applications, and broader incentives like carbon tax and the phase-out of fossil fuel subsidies will help reflect the true costs of technologies and close the cost gap for renewable hydrogen.

The technology pathway for hydrogen trade is also clear, and efforts are needed to demonstrate integrated value chains (from renewable energy to end use) and to scale up the different steps. A large part of the cost decrease can be achieved through this scale-up process, but the rest still needs innovation. Areas of attention include energy consumption for hydrogen liquefaction, and reconversion from the hydrogen carrier to pure hydrogen (which might not be needed in all cases). Technologies for the downstream uses also need to be demonstrated to develop the demand that will drive the need for trade. Demand includes, specifically, the production of chemicals and reduced iron, which represent large hydrogen users and can promote economies of scale with only a few plants and where the cost premium from hydrogen would only represent a small cost premium for customers down the value chain.

At the heart of this transition, measures to accelerate renewable deployment are needed. Electricity use for hydrogen must not displace more effective uses of electricity and instead needs to be additional. The deployment pace needs to at least triple from today's 290 GW/year to more than 1 TW/year in the coming decade.

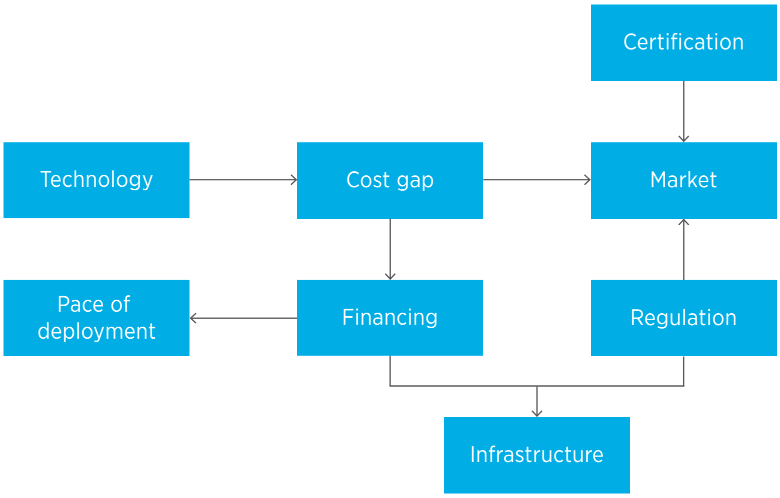
Previous sections of this report have shown the potential outlook for hydrogen trading and what could be achieved if efforts and development are aligned. The reality today, however, is far from that. Most of the international trade of pure (gaseous) hydrogen today takes place in countries in Northwest Europe, which are interconnected through a pipeline network[31] owned and operated

[31] *There are about 4 600 km of hydrogen pipelines around the world. The other main hydrogen network is in the United States, but it is only used for domestic transport.*

by Air Liquide. From 2010 to 2018, EU countries exported 0.06-0.08 $MtH_2$/year. Most of this trade was within EU Member States and with Switzerland (Hydrogen Europe, 2021). Trade of hydrogen derivatives such as ammonia and methanol is much more common (equivalent to 10% and 28% of global production, respectively), which could facilitate the initial trade, but this is only one of the factors that need to be in place to enable global trade. To go from this reality to one where hydrogen is traded at a similar scale to LNG today, multiple milestones need to be achieved. This chapter looks at the barriers that limit hydrogen trade development today and delineates some of the actions that can be taken in the short term to tackle those barriers.

The main barriers and some of their relationships are shown in Figure 4.1, followed by an explanation of the nature and characteristics of each barrier.

**FIGURE 4.1. Main barriers for infrastructure and trade development and relationships between them**




Technology (performance and scale) is one of the main factors defining the cost gap between hydrogen and alternative technologies. This cost gap is what has prevented the emergence of a market since it needs incentives to be overcome, and financing is also tied to this gap since the return needs to be attractive for capital to flow towards hydrogen infrastructure. The infrastructure development also needs guidelines on regulation since the infrastructure is a new class of assets. Other factors that are needed for the emergence of a market are certification of the hydrogen traded and the rules for such a market and how they evolve over time.

For the implementation of actions to address the barriers, one fundamental differentiator across countries needs to be considered: each country is at a different stage of development, with different decarbonisation targets, starting points, resources available and industrial landscape, among other factors. Similarly, one country might already have some specific incentives in place, while another is just exploring the potential benefit that hydrogen can have for its economy and system. To account for these differences, the concept of stages is used in the following sections to give a sense of the sequencing of the actions. The first stage is meant to represent the early days of market formation, when a country is still aiming to understand the best approach and scope for certification and implementing small pilot projects for trade to de-risk the technologies; this stage has the widest cost gap due to the low technology maturity. In the second stage, there is already infrastructure in place connecting some of the largest clusters, there are local prices with price disclosure, standardised contracts are being introduced, certification has moved beyond GHG and production only, trade projects are not pilots anymore but are going to commercial scale (although not yet at the world-scale needed), and the cost gap has closed thanks to deployment and policy incentives. In the third stage, there is widespread infrastructure that enables multiple valleys and price hubs to be linked; hydrogen certification schemes are consistent across countries and have a broad scope, covering multiple commodities, life cycle aspects and environmental, social and governance (ESG) aspects; global trade has been demonstrated at large scale; the largest improvements in technology have been achieved; the cost gap has narrowed down; and hydrogen or its derivatives have even become competitive in some applications.

## 4.1 Market creation

### Barriers hindering trade

Hydrogen is not widely traded today. Most of the production is captive, and even in industrial complexes with some merchant production, there are still only a few end users and usually a single supplier. There is no price index that reflects the price discovery resulting from the interaction between supply and demand.[32] Furthermore, production costs from existing natural gas plants are affected by long-term delivery contracts, which distorts the pricing for these facilities. The lack of pricing indexes is to a large extent defined by the absence of infrastructure that connects the various stakeholders in a single network. It is also linked to all the hydrogen being used for industrial plants that have a fixed hydrogen demand and have included such production as part of the scope (*i.e.* plants that have limited spare capacity).

While global trade could be enabled by large demand centres close to the shore (*e.g.* ports), it would benefit from supporting infrastructure onshore once the hydrogen is delivered. Such infrastructure can enable access from a wider range of users, and it can provide more flexibility by connecting users with different profiles and requirements, supporting demand and uptake.

There is also an absence of a "demand pull" for hydrogen, meaning that in most countries, there are no economic or policy incentives for hydrogen uptake. In industry, the focus is on energy efficiency and incremental changes rather than the step-changing approach required to adopt disruptive technologies such as hydrogen. In shipping, the current GHG strategy from the International Maritime Organization lacks the ambition to promote hydrogen derivatives (50% GHG reduction by 2050 versus 2008), and it does not include alternative fuels as part of the strategy. In aviation, only selected regions have targets for sustainable aviation fuels, but those targets are mostly for domestic aviation or do not include synthetic fuels as part of the scope. Some recent examples show that this trend is changing. For example, the *Fit for 55* package in the EU includes a 50% share for renewable fuels of non-biological origin in energy and feedstocks for industry by 2030, a 2.6% target for such fuels by 2030 for transport and a 0.7% target specifically for synthetic fuels from hydrogen in aviation.

There are also efforts from private industry that will drive hydrogen demand. For instance, European steel makers have announced projects that add up to 41 Mt/year of hydrogen-based steel-making capacity by 2030 (Gas for Climate, 2021b). The barriers are that this is still not widespread and that, depending on the definition of the target, the incentive for hydrogen might not be direct enough to promote its uptake (*e.g.* the target could be for renewable energy share, and hydrogen is only one of the eligible pathways). Incentives should aim to strike a

[32] *Indexes like S&P Global Platts estimate the production cost based on the cost of the energy input but are not the result of supply and demand interaction.*

balance between a target specific enough to promote hydrogen in a no-regret application while still leaving room for competition across technologies. Once these incentives are in place in potential importing countries, they will increase the hydrogen demand and support the case for hydrogen trade.

Another factor that makes the market creation more difficult is the lack of a method to trace the emissions associated to the production, transport and conversion of hydrogen (see Section 4.2), not only up to the point of use (*e.g.* a steel plant) but also in the downstream goods and services produced (*e.g.* a car). This means that users already looking to buy low-carbon products produced using green hydrogen and willing to pay more (*e.g.* a company aiming to decarbonise business travel with sustainable aviation fuels) cannot validate the raw materials used as input. This denies the possibility of linking a higher willingness to pay in some customers with the higher production cost that green hydrogen currently has. Once consumers can trace these emissions across the value chain, the case for hydrogen trade will become stronger for multiple reasons. First, domestic supply might not be able to satisfy the entire domestic demand due to competition with direct electrification or might be too expensive when compared with imports. Second, the higher price premium can cover some (or all) of the cost gap for green hydrogen pathways. Third, the lower transport costs of some commodities (*e.g.* synthetic oil) could be used to overcome high transport costs since the green molecules produced from hydrogen can also be traced across the value chain.

## Actions and roadmap to address barriers

During early stages of the market, there is a lack of infrastructure and a need for long-term certainty to justify the investment. One way to tackle this is through long-term agreements and integrated projects from supply to infrastructure and end use. At this stage, it is almost a one-to-one match between supply and demand, and there are at least three ways that price signals can start developing. The first is an index that is proxy for hydrogen production cost. In December 2019, S&P Global Platts launched a price index for North America and Europe and expanded to Asia and Australia in 2020 and 2021 (S&P, 2022). Similarly, in March 2021, E-Bridge Consulting launched a cost-based index (called "Hydex") for gas-based (with and without CCS) production and electrolysis. The index is published on a weekly basis, and it is targeted to the German market. In November 2021, EEX, a European power and gas exchange, announced that it was planning to launch an index in 2022. One approach to developing the index is to do it based on the underlying cost component. Electricity and gas are the major cost components of electrolytic and fossil-based hydrogen, and those have developed markets with price signals. The capital and operational cost could be added on top, with some default assumptions by region to be able to produce a hydrogen production cost variable over time.[33] The second way is that once the first few projects have been developed, there could be a transition to regularly surveying those projects and forming the index based on quotes for the purchase and sale of hydrogen by market participants (den Ouden, 2020). A third way to provide price information is through the winning bids of auctioning and hydrogen purchase agreements, if this mechanism is in place (EEX, 2021). Yet another way could be like the early days of natural gas, when price was indexed to the prices of competing fuels (Heather, 2021). This might not work for hydrogen since the competing fuels differ by application and the price point for hydrogen could change depending on the specific technology used for a specific fuel.

In a second stage, still without infrastructure developed, there could be a decoupling of physical and certificates trade. Thus, hydrogen certificates guaranteeing certain emission reductions from hydrogen production could be traded between hubs and countries, despite not being physically

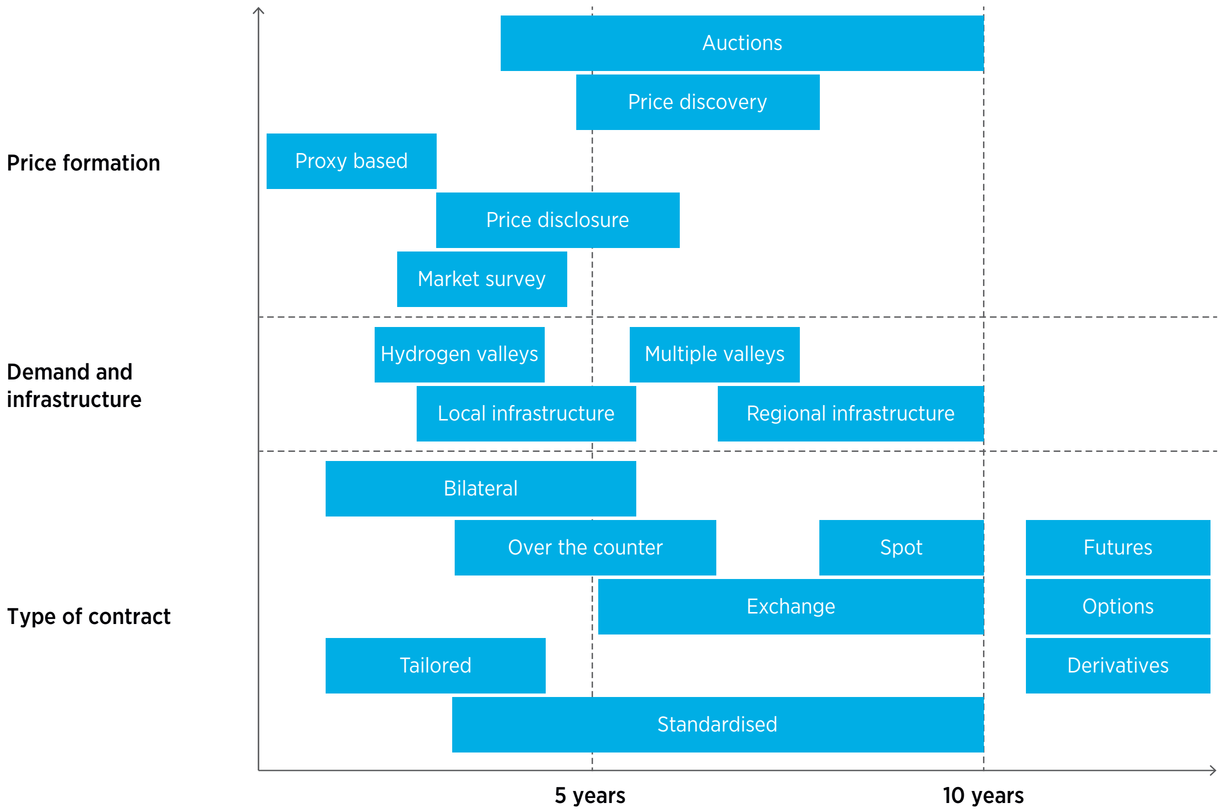
[33] *This is the approach being followed by S&P Platts.*

connected. This increases the market liquidity and efficiency and could increase the price of the certificates and therefore the incentives for green hydrogen production. This is only suitable for the early stages to promote market development and should be phased out once infrastructure has been deployed and enough suppliers and users are part of the same network. This also goes together with a robust certification scheme and measures to avoid double counting of the benefits.

The first few projects are expected to take place around large demand centres, which can be ports, airports, cities or industrial clusters (sometimes called hydrogen valleys). These have the advantage of requiring large volumes, which take advantage of economies of scale to drive costs down. Valleys could be developed with a staged approach in which not all the users will be converted at once. This can also lead to a staged construction of production facilities, which will have different production costs and, if connected to the same network, could lead to a supply curve with different price points and the development of local price indexes. Once multiple valleys have been developed, they could be connected through pipelines, effectively establishing a link between small-scale markets with different supply and demand dynamics. These valleys represent the first step change and would be useful in putting the initial demand in place, making incremental changes (*e.g.* the conversion to hydrogen) easier for other facilities in the vicinity.

Once enough suppliers and users are connected, there will be more competition, leading to lower pricing. This in turn can lead to the use of traded hubs to satisfy the risk management requirements of portfolios and the market participants interacting in the traded market via hubs. By this point, the trade contracts are standardised, facilitating transactions and an increase in volume traded (Heather, 2016). The transition to a market can start with over-the-counter trading (still bilateral but with standard amounts and terms) before moving to an exchange (with a clearing house). Figure 4.2 shows this market evolution across different dimensions, focusing on the developments needed in the coming decade.

**FIGURE 4.2. Milestones and developments for market-related aspects in the short term**



In the case of ships, the development could be similar to LNG. The first LNG contracts were bilateral and long term. There were take-or-pay clauses, which guaranteed a minimum volume that buyers would pay for regardless of whether they needed such volume. The LNG price was linked to a competing fuel rather than being based on the production and transport cost. The LNG bought could not be resold to third parties. These conditions guaranteed security of supply for the buyers, an offtake for the seller, and a fixed price with a balance between return on investment for the seller and non-volatile pricing for the buyer (IRENA, 2022d). In 2020, almost 55 years after the first LNG shipment, only about a third of the price formation was on the spot market and almost 60% was still with oil price escalation (IGU, 2021a). For hydrogen, the terms of these first few bilateral trades can be reported in the trade press and become the basis for price formation. After price disclosure comes price discovery and attracting more players to the market (Heather, 2016).

Once the basic market develops, other more complex components and financial instruments like futures exchange, spot market, derivatives, hedging, balancing (for transport and storage) and ancillary services will arise, but those will probably take more than a decade to reach maturity and are left outside the scope of this discussion.

Three conditions that are essential to developing the hydrogen market are anonymity, transparency and flexibility. Anonymity refers to the clearing house being the counterpart to all trade instead of direct exchange between specific suppliers and consumers. This also allows for small participants (*e.g.* small electrolysers). Transparency refers to making public the volumes and prices for the trade to develop confidence in the market (Heather, 2021). Flexibility refers to the system being able to cope with changes in supply and demand when there is an (un) planned event. During early stages, this is likely to come from supply adjusting its output either by ramping down production or temporarily shutting down some units. This could also come from a buffer provided by centralised storage.

Actions for the short term include defining the rules for hydrogen trade, establishing preconditions for the market, developing an initial design of the hydrogen price index, and embedding a certification scheme in the market design (den Ouden, 2020). Hydrogen is a versatile carrier used across the entire energy system. As such, the hydrogen market should be compatible with the electricity and methane markets, including avoidance of double incentives, transfer of certificates for renewability or emission reductions, flexibility provision, and progress towards decarbonisation goals. It should also be coupled to any carbon price or carbon trading scheme to enable the hydrogen price to be related to the $CO_2$ emissions of different technologies participating in the market.

## 4.2 Certification

### Barriers hindering trade

Hydrogen does not emit $CO_2$ upon use, so that makes tracking production and transport emissions essential to enabling global hydrogen trade to contribute to climate mitigation. There are multiple challenges in this respect. First, there are several schemes that are advanced in their definition (*e.g.* Australia, EU, United Kingdom) but none of them is implemented at large scale with actual production, which means it is early stages and schemes might still change as the process develops. Second, to enable global trade, there should be consistency in the methodological aspects (including boundaries, emissions included and factors used, treatment of co-products, among others) across countries to provide importers with a guarantee of the GHG emissions and the impact associated with the production of the hydrogen imported so that they can track progress towards their targets and ensure sustainability. Because of this, importers have an edge in establishing the guidelines for certification. Third, each of the transport pathways could require different boundaries and conditions (*e.g.* origin of the LOHC used), which makes the process of standardising the certification of transport more difficult. Lastly, while certification in shipping can be directly linked to physical trading, this might not be possible for trading through a pipeline network, which will require a different approach (*e.g.* mass balancing) to cope with the different qualities of hydrogen.

An additional challenge is that the standards set by a scheme need to strike a fine balance. It has to be strict enough to ensure progress towards decarbonisation and avoid loopholes that might lead to higher emissions (*e.g.* on-grid electrolysis with fossil fuels). It also needs to consider that the production of low-carbon hydrogen, infrastructure and use of hydrogen as an energy carrier is in its early days and overly restrictive criteria might stifle innovation and limit deployment. Poorly set definitions risk inhibiting future market sophistication for trade of hydrogen and could prevent ambitious suppliers (able to go beyond the thresholds) from producing hydrogen with lower emissions.

Certification could even become more difficult if a broader scope is set that covers sustainability. For instance, an importing country might want to verify that the hydrogen has been produced without negatively impacting domestic water supply. Certification could also be linked to additionality to ensure that hydrogen exports are not displacing the most effective domestic use of electricity. This will be especially important in countries that combine vast renewable resources with relatively low economic development, where hydrogen might be seen as an attractive opportunity for economic growth but could hinder the transition to a renewable system if not managed properly.

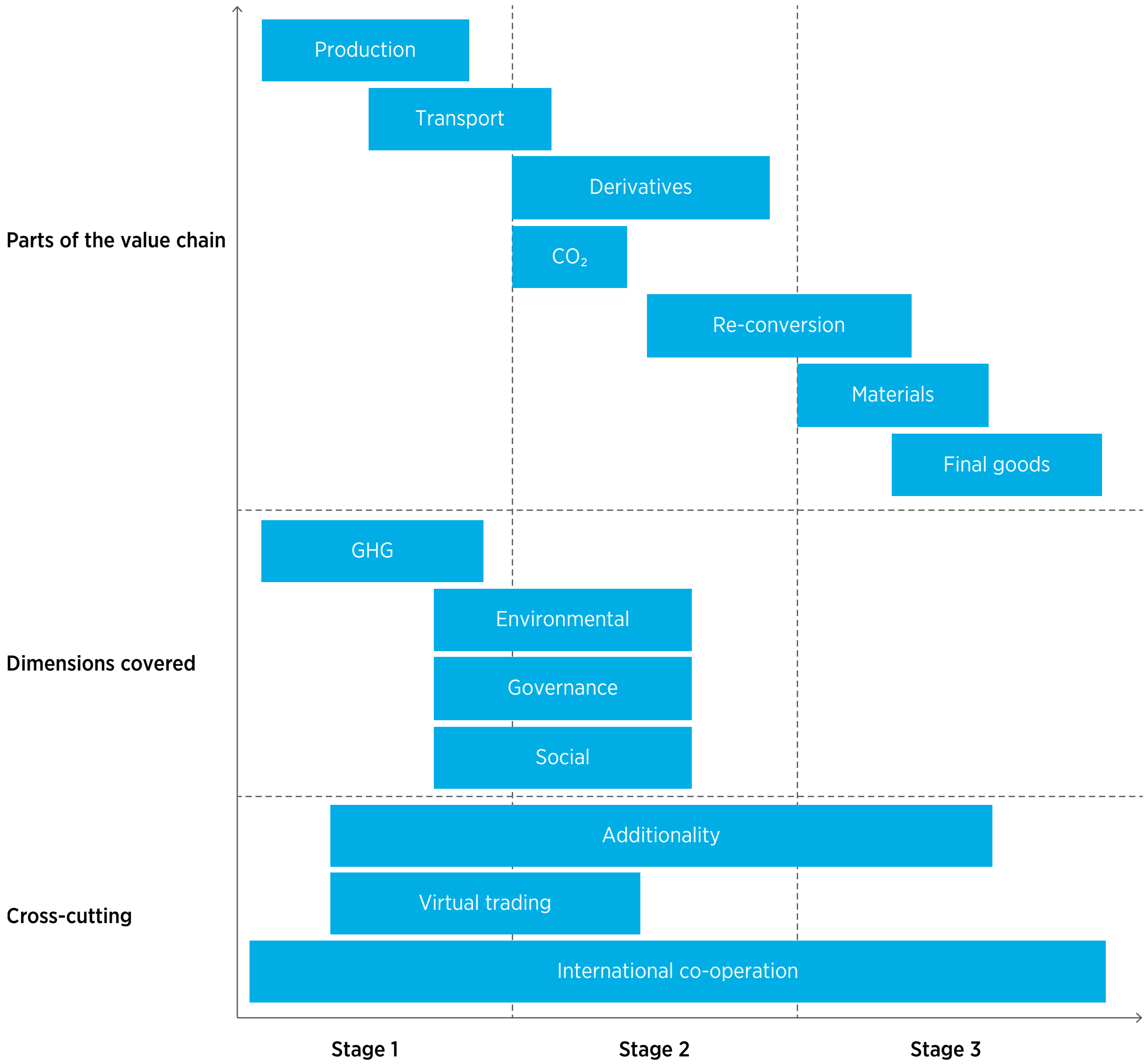
Definitions, thresholds and sustainability criteria could also vary across countries. This could lead to different markets developing in parallel, depending on the level of stringency, and potentially leading to market inefficiencies. This could lead, for example, to a few suppliers satisfying the requirements of the most stringent standards, leading to limited competition and higher costs. The development of different markets could result in uneven progress towards mitigation and could make it more difficult for project developers, who would need to consider multiple regulations and criteria when constructing a project, potentially increasing the administrative costs and duration.

Hydrogen can also be converted to other energy carriers and commodities. A challenge this introduces for trading is that certification would also need to cover such commodities so that it effectively makes the link between potential demand for green products and production of green hydrogen. If the certification covers the process up to hydrogen production, a plant transforming the hydrogen into ammonia and exporting such hydrogen to a country with a renewable target for fertilisers would not receive any incentive since fossil-based ammonia and green ammonia would be treated the same.

## Actions and roadmap to address barriers

To satisfy the needs of global trade, hydrogen certification must meet at least four conditions. First, at minimum, it needs to cover the entire supply chain, from energy source to hydrogen use in the importing country. It eventually also needs to cover hydrogen derivatives which can be more attractive for trade (including steel or synthetic fuels that are not reconverted to hydrogen). Second, aspects such as scope, boundaries and taxonomy need to be consistent across borders for countries to speak in the same terms when it comes to emissions or impact. Third, the certification needs to be broader than GHG emissions and cover other sustainability aspects (see Figure 4.3). Fourth, there should be a clear distinction between quantitative (lifecycle GHG emissions) and qualitative aspects (labels). Each country should be able to define their own standards (*i.e.* what is acceptable for their needs) but the underlying information should be transparent, clear, and common. This can allow for market diversity, support competition, and set a pathway that will continually push industry to improve their operating procedures. Additional factors to consider are: to include minimum and optional criteria; make compliance mandatory instead of voluntary, with market value rather than informative only; implementation of smaller projects to begin with, to test initial processes, instead of trying to have the entire scheme in place for large projects; consistency between energy carriers (electricity, methane, hydrogen and potential commodities) (IRENA, 2020c).

**FIGURE 4.3. Trade-related milestones for hydrogen certification in the coming decade**




Note: GHG = greenhouse gas.

Hitherto, most of the focus has been limited to the GHG emissions from the production step, taxonomy and thresholds for specific labels. There are already multiple efforts ongoing in these areas (see Table 4.1) (German Energy Agency/World Energy Council, 2022). Some of the efforts expand the scope by one step to cover ammonia as well, and the Smart Energy Council also aims to cover metals. Some of these processes are still under consultation and still to be enacted. For instance, the United Kingdom started the consultation process in August 2021 when it launched its strategy and published the low carbon hydrogen standard in April 2022 (UK Government, 2021). The Australian Government issued a discussion paper for consultation in June 2021, started trials in December 2021 and will propose a final design for the certification scheme once industry trials are done in 2023 (Australian Government, 2021a). In the United States, several bills have been proposed that cover carbon intensity for hydrogen: The Hydrogen Utilization and Sustainability Act would expand the tax credit for renewable electricity to include hydrogen and would define the qualified hydrogen as having a carbon intensity lower than 75 $gCO_2/kWh$ (US Congress, 2021a). The Clean Hydrogen Production and Investment Tax Credit would allow a new tax credit to produce clean hydrogen that achieves at least a 40% GHG reduction compared to steam methane reforming. The Build Back Better Act indirectly defines thresholds by providing the maximum benefit to projects with emissions lower than 0.45 $kgCO_{2\text{-}eq}/kgH_2$ and completely phasing them out beyond 6 $kgCO_{2eq}/kgH_2$. It also defines a 2 $kgCO_{2eq}/kgH_2$ threshold for clean hydrogen.

Current efforts are focused mostly on hydrogen production and on tackling aspects like system boundaries, allocation methods for co-products, cut-off criteria, inventory, accounting and verification. This step should at least be "well to gate", which includes raw material supply, processing, transport to site and the production itself. This means including potential methane leakage for the methane reforming pathway, which can have a large impact on GHG emissions (Bauer *et al.*, 2022). One of the most advanced efforts at the international level is the working paper from the International Partnership for Hydrogen and Fuel Cells in the Economy, which covers methodological aspects for four production pathways (IPHE, 2021). This should form the basis for future certification standards (*e.g.* through the International Organization for Standardization) since it is based on quantitative data rather than labels (*e.g.* blue, green) and contains standardised data sheets by pathway. While the criteria and thresholds for each proposed hydrogen certification scheme are different, there is one configuration that satisfies all of them: direct connection between the renewable power source and the electrolyser, a GHG reduction of 70% versus a fossil fuel reference, and direct air capture as the carbon source (if applicable) (German Energy Agency/World Energy Council, 2022).

The efforts for the certification scheme could also be useful in putting the trade rules and regulations in place. A condition to establish a contract is that the buyer and seller should have the same definition of the product. Within the World Trade Organization framework, items are defined using the Harmonized Commodity Description and Coding System, also called the Harmonized System. Import custom duties, taxes and other charges are made based on this system. Liquid and gaseous hydrogen have the same code in this system, and there are no codes for LOHCs, since most of them are not internationally traded. Duties and taxes will also impact the import cost of hydrogen (and hydrogen carriers) and will therefore also impact the competitiveness of hydrogen. These duties and taxes are mostly based on the monetary value of the cargo and not on volume, mass or energy content, so the impact on delivered cost will be different by carrier (IPHE, 2022). Another common boundary between certification and trade rules is that there should be an agreement on how emissions from hydrogen production and transport should be accounted.

**TABLE 4.1. Standards and regulations defining low-carbon hydrogen or its derivatives**

| REGION/BODY | REFERENCE | THRESHOLD/ LABELS | QUALIFYING PROCESSES | NOTES |
|---|---|---|---|---|
| **United States** | Hydrogen from natural gas | 40% GHG reduction (2 $kgCO_2/kgH_2$) | Methane reforming, electrolysis, nuclear | Build Back Better Act (proposed) |
| **EU – Taxonomy for sustainable activities** | Fossil fuel for transport (94 $gCO_2$/ MJ) | 73.4% GHG reduction (3 $kgCO_2/kgH_2$) | Any process achieving the threshold | Also covers hydrogen-based synthetic fuels |
| **EU – CertifHy** | Hydrogen from natural gas | 60% lower than reference (36.4 $gCO_2$/MJ) | Fossil based and renewable | Is a guarantee of origin scheme rather than full certification |
| **EU – Hydrogen and decarbonized gas package** | Fossil natural gas | 70% GHG reduction | Biogas, biomethane, renewable gases, hydrogen, synthetic methane | Complementary to the Renewable Energy Directive |
| **United Kingdom** | Transport fuels | 55-65% GHG reduction | Conversion of renewable sources | Renewable Transport Fuel Obligation |
| **IPHE** | - | - | Electrolysis, gas reforming with CCS, industrial by-product, coal gasification with CCS | Does not define thresholds but only covers methodology to quantify emissions |
| **Australia** | - | - | Electrolysis, coal gasification with CCS, methane reforming with CCS | Not finalised (trials started in December 2021) |
| **Smart Energy Council (Australia)** | - | Renewable | Renewable hydrogen and derivatives | Industry led; covers hydrogen, ammonia and metals |
| **Ammonia Energy Association** | - | Low-carbon ammonia | 12 production pathways | Based on discussion paper for consultation (AEA, 2021) |
| **WBCSD** | Hydrogen from natural gas | Reduced carbon[a] (< 6), low carbon (< 3), ultra-low carbon (< 1) | Methane reforming, electrolysis, nuclear | Private sector initiative |
| **China** | Coal | Low carbon[a] (14.51), clean and renewable (4.9)[b] | Coal gasification, methane reforming, electrolysis, chlor-alkali, coke oven gas | Hydrogen alliance (private sector) |

Note: This table focuses on updates since Q4 2020. For an overview until then, see Table 2.1 of IRENA (2020a). A recent review of hydrogen certification schemes is available from German Energy Agency and World Energy Council (2022). CCS = carbon capture and storage; EU = European Union; GHG = greenhouse gas; IPHE: International Partnership for Hydrogen and Fuel Cells in the Economy; WBCSD = World Business Council for Sustainable Development.
[a] Numbers refer to GHG emissions from hydrogen production in $kgCO_{2\text{-eq}}/kgH_2$.
[b] Same threshold for clean and renewable, with difference being the nature of the energy input.

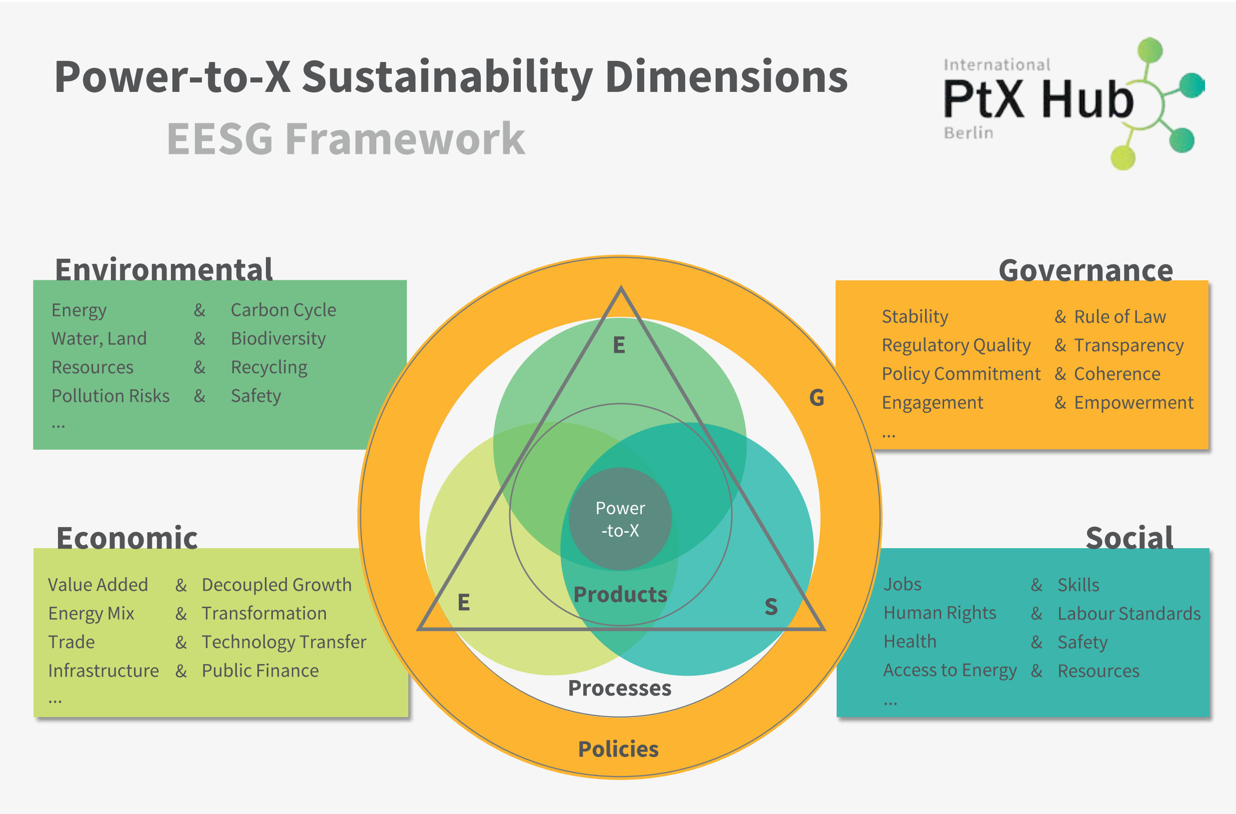
The next step is to broaden the scope to include conversion to a carrier and the transport step itself. Like production, where each pathway requires different boundaries and components (*e.g.* methane emissions), the conversion step will require definition of boundaries for each pathway. For example, LOHC hydrogenation has a large heat release, and its emissions will depend on the benefit assumed for such heat. In contrast, hydrogen liquefaction uses a large amount of electricity, which may not be renewable, since the liquefaction could be located at the port while the hydrogen production could be inland. The International Partnership for Hydrogen and Fuel Cells in the Economy is already embarking on efforts to agree on the methodology for some of these issues, and a draft should be available later in 2022. A similar approach is needed for the reconversion to hydrogen (if necessary), and the methodology for the heat consumed will be critical. A modular approach with separate certification for each step in the value chain (production, conversion, transport) might facilitate the process of defining the certification scheme since it simplifies the scope (White *et al.*, 2021). Certification efforts that are already covering ammonia as a conversion pathway include those from the Ammonia Energy Association, the Smart Energy Council in Australia, and the Midwest Renewable Energy Tracking System in the United States.

Global hydrogen trade can also take place in the form of other carbon-containing molecules, such as methanol or jet fuel, that do not necessarily need to be converted back to hydrogen. This introduces another layer of certification, where the $CO_2$ also needs to be tracked and a methodology is needed to account for the energy consumption of its capture and transport. This could build on the efforts for carbon offsetting and certification of negative emissions, which also involve $CO_2$ capture (on top of permanence). For instance, the Low Carbon Fuel Standard in California includes direct air capture for fuel production as part of its scope, and direct air capture can be located anywhere in the world. In December 2021, the European Commission proposed to establish an EU standard to monitor, report and verify GHG emissions for captured fossil, biogenic or atmospheric $CO_2$ that is processed, stored or re-emitted. The proposal includes the target of having a regulatory framework for the accounting and certification of carbon removals by the end of 2022 (EC, 2021a).

To achieve the full value of certification, GHG emissions should be accounted for throughout the value chain all the way to the consumer. For instance, a car manufacturer aiming to decarbonise its life cycle operations should be able to validate the GHG emissions from steel production. This is much broader than hydrogen only, but it requires consistency and alignment as the certification scheme is developed to enable a smoother integration later. At this point, there should be engagement with end-use organisations that have ongoing sustainability efforts. For example, for steel, the World Steel Association has a life cycle inventory methodology (World Steel Association, 2017, 2021) and there is the Responsible Steel Standard and ISO 20915 (ISO, 2018). For fertilisers (main use of ammonia today), Fertilizers Europe (an organisation of fertiliser producers in Europe) uses a carbon footprint calculator to estimate $CO_2$ emissions from its operations and couples the calculator with a certification scheme (IEA, 2021e). Given the versatility of hydrogen, the broader the scope of the certification scheme, the larger the incentives to globally trade the energy (*e.g.* a country with a certification scheme that includes steel use for cars will capture more incentives for trade than a country without such a scheme).

In terms of impact measured, the parameter that receives the most attention is GHG emissions due to its direct link with climate change. However, hydrogen should be seen within a broader sustainability framework, including other environmental, economic, social and governance aspects. Other environmental aspects to consider beyond GHG include water, land, recycling, biodiversity and air pollution. The economic dimension includes creating added value and promoting a sustainable growth in income and employment and covers aspects such as infrastructure, trade and public financing. The social dimension includes not having a negative impact on the local community in terms of human rights, health and safety risks, or access to energy. Governance refers to aspects such as transparency, political stability and stakeholder engagement (see Figure 4.4) (PtX Hub, 2021). One of the certification initiatives already moving in this direction is the Green Hydrogen Organization. This non-profit organisation launched in September 2021 and is supported by private funds. It is planning to set up a green hydrogen standard that extends beyond what the International Partnership for Hydrogen and Fuel Cells in the Economy is doing and to use ESG aspects and align with the Sustainable Development Goals beyond climate change (GH2, 2021).

**FIGURE 4.4. Environmental, economic, social and governance framework for Power-to-X sustainability dimensions**




Source: PtX Hub (2021).

The broad range of factors in Figure 4.3 and Figure 4.4 does not mean that a certification scheme should have everything in place (*i.e.* coverage broader than GHG, inclusion of derivatives and further products downstream, inclusion the entire value chain) before being implemented; instead, the range of factors shows the direction that each scheme should strive for. This is useful during the initial phase of the scheme, when it is being designed, and facilitates the integration of those subsequent steps. Similarly, some aspects might be more relevant for some countries, so they might be brought forward to an earlier stage of implementation than in the indicative sequence shown in this section.

## 4.3 Technology

### Barriers hindering trade

Not all the technologies discussed are commercially available today (IRENA, 2022b). This creates uncertainty about the cost that some of the large-scale facilities could have, since there are no previous reference points. For instance, hydrogen liquefaction is a fully commercial technology, but the largest scale is only 35 tonnes (t) per day, which would need to be at least 25 times larger to reach the minimum scale, where costs are the lowest across the value chain. New engineering challenges may arise with this massive scale-up, requiring proof of technology and de-risking.

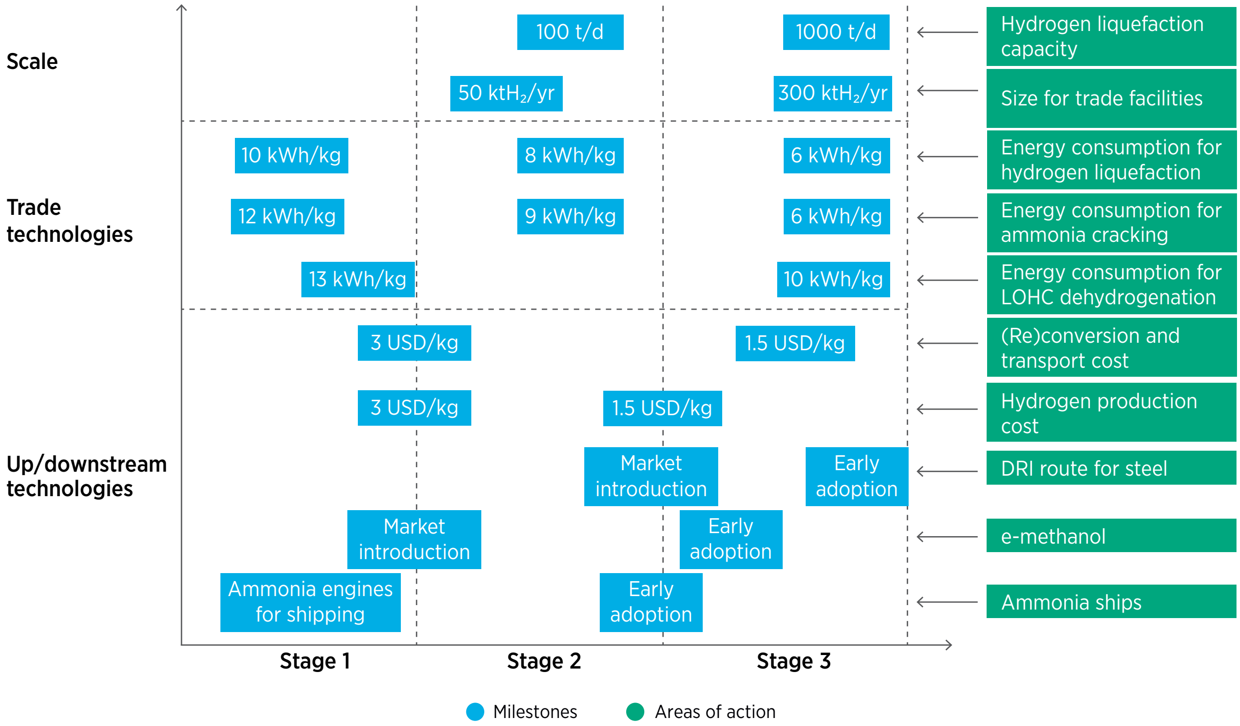
The low technology maturity for some steps (*e.g.* LOHC dehydrogenation) could also lead to longer lead times to achieve the large scale since it is not only a matter of engineering and deployment but also moving through the innovation funnel from research to demonstration and commercialisation. Similarly, it is not only a matter of proving that each technology works and performs as expected but demonstrating the integrated concepts from renewable energy to hydrogen carrier and all the way to the service delivered in an importing region.

The main challenge for technology is that the role for trade identified in this report relies on a performance that is yet to be achieved. Some of the key parameters are conversion costs and energy consumption for the carrier reconversion step. Outside the specific technology steps, if innovation unlocks direct ammonia use for multiple applications, it will also prevent the need for reconversion, improving the overall efficiency by system design rather than technology-specific research.

### Actions and roadmap to address barriers

Regarding technology, efforts can roughly be divided into technologies directly related to trade (see IRENA, 2022b), those having a direct impact on the transport cost and those related to the supply (IRENA, 2020b) and end use, which will have an impact on overall hydrogen competitiveness and indirectly affect uptake and trade. For trade, the levers that are expected to have the largest impact on transport cost are technology performance, economies of scale, and global learning-by-doing. In the area of technology performance, the parameters with the largest positive impact and largest gap for improvements are energy consumption for hydrogen liquefaction, ammonia cracking and LOHC dehydrogenation. The largest lever to reduce the transport cost is to scale up a single trade facility. The full economies of scale are reaped with project sizes of 0.3, 0.65 and 0.95 $MtH_2$/year for LOHC, ammonia and liquid hydrogen, respectively (IRENA, 2022b). At the same time, these sizes will not be reached until the global market develops (*i.e.* multiple trading routes being established and scaling up). So far, there are three regions with explicit targets for trade: Japan has a target of 300 $ktH_2$/year by 2030 (out of 3 $MtH_2$/yr of demand), the Russian Federation targets 20% of the global market by 2030 and exports of 2 Mt/year by 2035, the United Arab Emirates aims to capture 25% of the global market by 2030, and the EU has a target of 10 $MtH_2$/year of imports by 2030 (EC, 2022). This scale will not be achieved without a simultaneous increase in demand, where industrial applications should reach maturity and commercialisation within the next 10-15 years. Figure 4.5 shows some of the milestones for some of these trade-related areas for the coming 15 years (considering that full technology development will most likely take more than a decade).

**FIGURE 4.5. Milestones and developments for market-related aspects in the coming decade**




Note: DRI = direct reduced iron; LOHC = liquid organic hydrogen carrier.

Today, industrial-scale (already built) liquefiers of 5-35 t/day can achieve 9-12 kWh/kg$H_2$. Once larger liquefiers in the range of 100 t/day are deployed, the energy consumption could decrease to 6-8 kWh/kg$H_2$, and once very large liquefiers, larger than 2 000 t/day are deployed, 6 kWh/kg$H_2$ could be achieved. If hydrogen liquefaction is to reach a similar scale to LNG today, it needs to scale up by multiple times. The largest LNG train today (Qatari LNG) has a capacity of about 21 350 t/day. Even considering that the energy content of LNG is close to a third of hydrogen, this is still orders of magnitude larger than the largest 35 t/day hydrogen liquefaction plant. While specific equipment like compressors or heat exchangers will make it difficult to reach the same scale, it is expected that hydrogen liquefaction trains will scale up significantly as the market need arises, leading to cost decreases (IRENA, 2022b).

This study shows that most of the ammonia trade is for ammonia use as feedstock and fuel rather than as a hydrogen carrier. But even to fulfil such a role, further advancement of ammonia cracking is necessary to reduce the energy penalty – especially since the importing region will have more expensive energy, so any energy consumed in the cracking will have either a high cost or a high energy penalty (if the transported hydrogen is used as a heat source). This consumption is largely influenced by heat integration and steam generation, so it could be as high as 30-40% of the energy contained in the hydrogen. With design optimisation, this could decrease to 14-15% energy efficiency (including hydrogen purification) (Topsoe, 2021).

At the same time, hydrogen production costs should decrease drastically in the coming decade. Innovation, increase of manufacturing capacity and scaling up of single modules and global capacity could reduce the investment costs of electrolysers by at least 40% in the short term, which when combined with the ongoing decrease in the cost of renewable electricity should lead to a level below USD 2/kg$H_2$ within the next decade. This will largely depend on the specific electricity cost for a location, but multiple governments and initiatives have announced explicit production cost targets. The US Department of Energy has a USD 1/kg$H_2$ target by 2031 in its first

Energy Earthshot (U.S. Department of Energy, 2021). Australia announced the "H2 under 2" target in its Technology Investment Roadmap, which refers to a hydrogen production cost of AUD 2/kg$H_2$ (about USD 1.5/kg$H_2$) by 2030 (Australian Government, 2020). Mission Innovation has a target of USD 2/kg$H_2$ by 2030 (including delivery to the end user) (Clean Hydrogen Mission, 2021). Chile has a target of USD 1.5/kg$H_2$ by 2030 in its national strategy. Similarly, to be in line with a 1.5°C scenario, DRI for steel production, electrolytic methanol and ammonia would need to reach commercial scale by the mid-2030s (IEA, 2021c); otherwise, it will be more challenging to reach the 2050 capacities. Ammonia engines for ships are already being developed by MAN ES (the largest marine engine manufacturer) and should be ready by 2024 for new vessels and 2025 for retrofits.

## 4.4 Cost gap

### Barriers hindering trade

There are at least three trade aspects related to cost: high capital cost across the entire value chain; high energy cost due to efficiency losses in transformation steps; and high transport cost. Regarding the capital cost, hydrogen technologies are being manufactured in relatively small volumes, resulting in high specific costs. The installed electrolyser capacity is still less than 0.3 GW, and most of the manufacturing plants are still in the order of 200-300 MW/year and not yet reaping the economies of scale. This, combined with relatively small electrolyser modules, results in a relatively high contribution of the electrolyser to the total production cost, but there are clear strategies to reduce it (IRENA, 2020b). The higher cost also applies to downstream use. For instance, the investment and fixed operating cost for DRI production with hydrogen are in the order of 30-50% higher than the primary route (including the electrolyser) (Vogl, Åhman and Nilsson, 2018). For power, combined cycle gas turbines designed for hydrogen can be 15% more expensive than natural gas ones (Vartiainen *et al.*, 2021). The difference is even starker when fuel cells are considered, potentially becoming more than three times as expensive than gas turbines when compared on a US dollar per kilowatt basis (FCH JU, 2020). Fuel cells also present some advantages over gas turbines, such as higher efficiency (being more favourable for partial loads) and a lower installed capacity (1 GW for fuel cells in 2019 versus over 1800 GW for gas turbines, including 140 turbines that operate with hydrogen), which means greater opportunities for cost reduction and lessons learned from technology deployment. As long as this cost gap persists, it will be more difficult to justify the business case for demand, establish a market and justify the long-distance trade. While the cost gap is expected to close for some applications (*e.g.* ammonia production as feedstock), the gap is expected to remain for others (*e.g.* synthetic fuels for aviation), requiring other mechanisms (*e.g.* hydrogen quotas) to promote market uptake and fiscal sustainability.

The efficiency losses translate into a higher cost of service delivered. Electrolysis already loses 25-35% of the energy as waste heat. Further conversion to methanol, ammonia or synthetic fuels (through Fischer-Tropsch synthesis) carries another 15-20% loss. Downstream conversion to power in a fuel cell is another 40%. Thus, the input energy cost will at least be doubled when expressed in final energy. For instance, an electricity price of USD 20/MWh is already equivalent to about USD 66/bbl when the electricity is used for synthetic fuels. The cost of the $CO_2$ can also be significant. A cost of USD 100/t$CO_2$ would add USD 40-45/bbl. These losses make it more difficult for hydrogen and its derivatives to become competitive with their fossil fuel counterparts. Even if the production cost is comparable to fossil fuels, a barrier today is that the international transport cost of hydrogen is too high (IRENA, 2022b), and it would not compensate for the cost differential between regions. Pipelines, ships, terminals, storage, and the entire infrastructure are too small to achieve the minimum size needed for economies of scale.

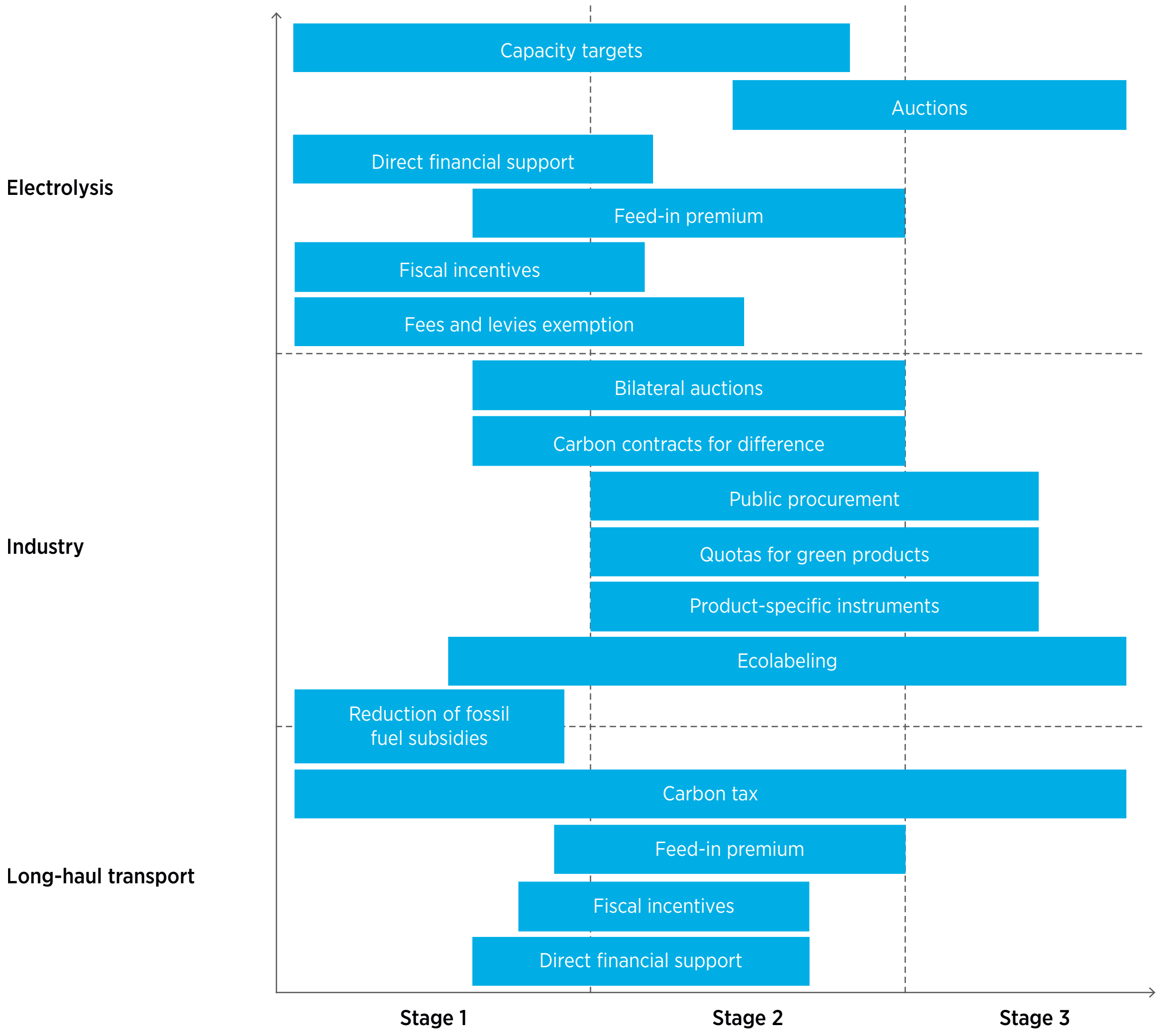
## Actions and roadmap to address barriers

IRENA has already analysed the policies needed to tackle the high cost of electrolysers and the electricity input (IRENA, 2021c) and the use in industry (IRENA, 2022e).

The cost gap can be closed by explicit economic measures or indirectly by other policies. For example, capacity targets, targets for electrolyser manufacturing capacity, or hydrogen quotas for specific sectors are not providing economic support but have a direct impact on the cost gap since they affect volume, promoting economies of scale and effectively leading to lower costs.

Narrowing down the scope to economic measures, there are basically two types of instrument: the ones tackling the capital cost and the ones tackling the operational cost or, directly, the cost premium. These can be targeted to the supply side (electrolysis) or to downstream applications (see Figure 4.6).

**FIGURE 4.6. Policies to address the high capital and operational cost across the hydrogen value chain**




Source: IRENA (2021c).

One of the policy instruments that can be used for the capital cost is direct financial support in the form of grants and loans, with the aim of reducing the capital that needs to be obtained through project financing, improving the recovery of the capital and improving the business case. Such instruments can be useful for the capital cost premium of electrolysers, steel production (through DRI), and ammonia and methanol plants. In the United States, the Infrastructure and Investment Jobs Act, approved in November 2021, includes USD 1 billion for electrolysis demonstration programmes and should be enough to fund at least 1 GW of electrolyser capacity. In Australia, the Government has provided a total funding of AUD 1.2 billion, out of which AUD 464 million is to be used to develop up to seven clean hydrogen industrial hubs (Australian Government, 2021b). In the EU, the European Commission has launched two calls from the Innovation Fund targeted at low-carbon technologies including hydrogen. In the first one, EUR 60 million was allocated to the development of a 100 MW electrolyser, and in the second, EUR 32.4 million was awarded to the Refhyne II consortium to demonstrate a 100 MW electrolyser in a refinery in Rhineland (Germany). In the United Kingdom, the Net Zero Hydrogen Fund, with a size of GBP 240 million (British pounds), supports the commercial deployment of new low-carbon hydrogen production to be delivered between 2022 and 2025. Additional funds from the United Kingdom include GBP 60 million from the Low Carbon Hydrogen Supply Competition and GBP 41 million from the Industrial Decarbonization Challenge fund to accelerate low-carbon hydrogen supply options. In Guangzhou (China), a three-year discount of up to CNY 5 million (Chinese yuan renminbi) per year is given to corporate loans for hydrogen projects.

Fiscal incentives would have a similar purpose to grants: to make the repayment of the project financing easier and improve the business case. For example, the proposed Build Back Better Act in the United States includes up to USD 3/kg production tax credit for 10 years, with the credit being proportional to the $CO_2$ emissions from the process; the full benefit is awarded to projects achieving 0.45 $kgCO_{2eq}/kgH_2$, and the credit is reduced to at least a third for projects with higher emissions. Fiscal incentives could also be used to decrease the project financing costs of downstream applications like steel or chemical plants.

Feed-in premiums and exemption from taxes and levies are meant to tackle the cost contribution of electricity. Electricity can represent 60-80% of the total hydrogen production cost (IRENA, 2020b), while taxes and fees can represent up to 80% of the electricity price (IRENA, 2021c).[34] Exempting electrolysers from these levies or using feed-in premiums, can close the gap between renewable and fossil-based hydrogen and can make a big difference during the early stages. These premiums could also be used for the final products. For instance, synthetic fuels are five to eight times more expensive than fossil jet fuel (Ram *et al.*, 2019; Ueckerdt *et al.*, 2021); feed-in premiums could help close this gap while the scale and efficiency increase and the gap is partially closed through technology development. Auctions are well placed for price discovery in early stages of the market when there is uncertainty on how to price the hydrogen but already after hydrogen deployment has started. An advantage of auctions is the flexibility in the design, including auction demand, qualification requirements and winner selection, which can be tailored to satisfy multiple requirements (IRENA, 2021c).

A wide range of industrial policies are available to policy makers to protect and support hydrogen in industry (IRENA, 2022e). Among them are public procurement and CCfD. In 2017, public procurement accounted for 12% of gross domestic product in Organisation for Economic Co-operation and Development countries and up to 30% in developing economies. Thus, public

[34] *The most extreme case is Denmark; most EU countries have a considerably lower share (see Figure 2.4 of IRENA [2021c]).*

procurement represents a large financial flow to promote the use of low-carbon services and goods and is large enough to drive demand in initial stages of deployment (becoming smaller as the market develops). Construction of buildings and infrastructure (*e.g.* bridges) constitutes about half the steel demand (IEA, 2021f), and it is one of the sectors where public procurement can have the largest influence through a demand pull that contributes to market creation. CCfD, in contrast, directly address the cost gap by establishing targets for the carbon price (called the "strike price") and paying for the difference between this strike price and the price from an emissions trading scheme, which can remove the risk of variable $CO_2$ prices from the scheme. CCfD can have a fixed duration for support and can be regularly revised to decrease the strike price. They also have the advantage that if $CO_2$ prices increase significantly, beyond what makes the technology attractive, the industrial producer would have to pay for the difference instead of receiving a subsidy. CCfD can also be auctioned, promoting competition and leading to lower total cost (McWilliams and Zachmann, 2021).

Two policies that are cross-cutting are the phase-out of fossil fuel subsidies and the adoption of carbon pricing. Explicit fossil fuel subsidies[35] have hovered around USD 500 billion during the 2015-2019 period, after reaching a peak of USD 800 billion in 2012 (Timperley, 2021). Broadening the scope of these subsidies to include the environmental impact (air pollution) would increase them to USD 5.9 trillion in 2020, or about 6.8% of global gross domestic product (IMF, 2021). Phasing out these subsidies would increase the average prices of fossil fuels and close part of the cost gap with hydrogen. Carbon tax would have a similar effect of internalising one of the externalities (climate change) into the price of fossil fuels, but by 2021, only about 21.5%[36] of the global GHG emissions were covered by a carbon price and less than 4% of the total emissions had a price higher than USD 40/$tCO_2$ (World Bank, 2021).

## 4.5 Financing

### Barriers hindering trade

Developing the hydrogen infrastructure for trade will require the commitment of large amounts of capital. Unlike, for example, hydrogen for road transport applications, where there can be progressive network development and the minimum investment is determined by the size of a single station, trade infrastructure is only economically feasible when large scales are used and the full benefit of economies of scale is reaped. Furthermore, infrastructure cannot be developed in isolation and must go together with supply and demand. This makes the total investment even larger, makes the project more complex, increases the risk, decreases the possibility of applying blueprints from other experiences, increases the lead time, and reduces the number of companies and financing institutions that can take such projects.

While hydrogen technologies are relatively nascent for most parts of the value chain, it is expected that as deployment advances and costs decrease for the different applications, hydrogen will progressively reach cost competitiveness among low-carbon technologies, and once it reaches this point, it will start attracting capital flows without the need for public incentives. For instance, on the supply side, deploying 100 GW of electrolysers could already reduce the capital cost of electrolysers by 40%, which combined with the continuous decrease

*[35] These include production subsidies or tax breaks (which reduce the production costs) and consumption subsidies (which cut fuel prices for the end user by fixing a price) (Timperley, 2021).*

*[36] Equivalent to 11.65 $GtCO_{2-eq}$, out of which about 4 $GtCO_{2-eq}$ is from China, which only covers the power sector and not industry, which is the relevant sector for this section.*

in renewables cost could achieve cost parity with the fossil fuel route within the next decade (IRENA, 2020b). On the demand side, DRI with hydrogen could be competitive with the blast furnace route in the early 2040s (BNEF, 2021). For infrastructure, the full economies of scale are reaped with project sizes of 0.4, 0.4 and 0.95 $MtH_2$/year for LOHC, ammonia and liquid hydrogen, respectively (IRENA, 2022b). The smaller scale of 400 $ktH_2$/year would require an investment (including from electricity generation to reconverted hydrogen at the import terminal) of about USD 4.7-6.0 billion today. To put this into perspective, a world-scale LNG plant is about 10 Mt/year (energetically equivalent to about 3.75 $MtH_2$/year) and requires an investment of about USD 20 billion[37] (Steuer, 2019). A difference, however, is that LNG is already a developed industry, satisfying 13% of global gas production (BP, 2021).

The current pipeline until 2030 for projects across the entire value chain adds up to USD 160 billion to produce more than 18 Mt/year of clean hydrogen, but only USD 20 billion of that is dedicated to infrastructure (Hydrogen Council, 2021). In Europe, multiple countries have also allocated some funds to hydrogen. Funds where hydrogen is included (among many other technologies) add up to EUR 54 billion, out of which EUR 12 billion is dedicated exclusively to hydrogen. The countries with the largest allocation are France, Germany, Italy and Spain (Hydrogen Europe, 2021). Several countries have announced dedicated funds for hydrogen,[38] with their hydrogen strategies including EUR 9 billion from Germany, EUR 7 billion from France, EUR 1 billion from Portugal,[39] and almost USD 19 billion from Japan out of which a large share is expected to go to trade infrastructure, given Japan's expected future reliance on imports. In Japan specifically, USD 2.6 billion from the Green Fund in 2021 was allocated to the development of a large-scale supply chain for hydrogen.

The relative novelty of some of the technologies in the value chain, not only for transport but also for end use (*e.g.* steel reduction), will also lead to a higher risk perception due to the uncertainty in technology, project execution, liability and regulation, among other factors. This will translate into a higher WACC and higher delivered cost, which will affect competitiveness. The WACC difference could be a further differentiator between transport pathways. For instance, the WACC for a large-scale project producing green ammonia at large scale and shipping it without reconversion is expected to be lower than for liquid hydrogen or LOHC, resulting in a double penalty for those technologies (higher total investment and higher WACC).

## Actions and roadmap to address barriers

Infrastructure can be financed with debt from international financing institutions, commercial banks and corporate bonds, for example. It could also be financed by equity from network operators or from investors, but the level of investments is usually much higher than the cash flows from the operators. With a regulated infrastructure, the investment is usually recovered through set tariffs that consider the payment of the financing and a regulated return (Gas for Climate, 2021a). Since infrastructure projects need to be constructed with future flows in mind, there might be a period where the flows are not enough to pay the corresponding financing share. Some alternatives to deal with this are grants to reduce the initial investment or capacity payments to cover the difference between targeted capacity and actual capacity. Individual projects can also be evaluated stand-alone and financed individually with a fixed set of suppliers

[37] *The historical specific capital cost varies widely (USD 400-1900/t), and project delays can also contribute to higher investments (Steuer, 2019).*

[38] *The Netherlands has earmarked EUR 15 billion for advanced renewable energy carriers, which presumably includes hydrogen.*

[39] *Aiming to mobilise EUR 7-9 billion of total investment.*

and end users. To minimise the risks, these individual projects should eventually become part of the regulated assets with a guaranteed return.

In Europe, four major instruments could be used for infrastructure development. First, InvestEU has a public contribution of EUR 26.2 billion, which is expected to mobilise EUR 362 billion by 2027. Its scope is broader than hydrogen, and even within hydrogen it covers the entire value chain, but sustainable infrastructure is one of the four main policy areas targeted by the fund. Second, the Connecting Europe Facility for Energy supports the implementation of the Trans-European Networks for Energy (TEN-E) regulation, which promotes the interconnection of energy infrastructure across Europe. This instrument has a total budget of EUR 5.84 billion until 2027 and can fund up to 50% of the total CAPEX of a project (EC, n.d.). In December 2020, the Commission proposed to expand the scope of the TEN-E regulation to include hydrogen infrastructure projects in the list of eligible Projects of Common Interest. A final decision on the proposal is expected by mid-2022 at the latest. Third, the Important Projects of Common European Interest (IPCEI) initiative was launched for hydrogen in December 2020; the projects are part of the EU Industrial Strategy and are meant to bridge the gap between R&D and commercialisation. In Germany, 62 IPCEI projects adding up to EUR 8 billion were pre-selected in May 2021, including 15 projects on infrastructure. In November 2021, the European Clean Hydrogen Alliance, which is a multi-stakeholder platform with over 1 500 members that aims to advance the large-scale deployment of hydrogen technologies, announced a project pipeline of over 1 500 projects, out of which one in eight was in transmission and distribution. Fourth is NextGenerationEU, a COVID-19 recovery fund with a total size of EUR 750 billion to be spent within the same time frame as the Multiannual Financial Framework (2021-2027). Approximately EUR 9.3 billion from this fund has already been committed to renewable and low-carbon hydrogen.

In the United States, the Infrastructure and Investment Jobs Act was approved by congress in November 2021. It includes USD 8 billion to be spent between 2022 and 2026 in four clean hydrogen hubs to demonstrate various pathways, including hydrogen production from renewables, fossil fuels and nuclear to be used across all sectors (power, industry, commercial-residential heating, and transport) (US Congress, 2021b).

## 4.6 Pace of deployment

### Barriers hindering trade

Global trade introduces two complications: (1) additional conversion steps to transform hydrogen into a more suitable form for transport, often followed by reconversion, with both steps resulting in conversion losses; (2) energy consumption for the shipping itself, which will further decrease the energy delivered. While pipelines do not require conversion, there is still a compression step that requires energy both to initially achieve the transport pressure and to compensate for the transport losses along the line. All these losses will ultimately translate into more renewable energy needing to be produced, which can in turn increase the need for renewable capacity deployment. This pace of deployment already needs to accelerate multiple times to achieve a net-zero GHG scenario by 2050 from about 290 GW/year for wind and solar in 2021 (IRENA, 2021f) to over 1 TW/year by the mid-2030s. Any additional losses introduced from hydrogen conversion and shipping will put even more pressure on increasing the pace of deployment and will make it more challenging to achieve the net-zero GHG goal.

One challenge that a limited renewables deployment rate introduces is that direct use of electricity might be displaced by hydrogen production for export. This could happen, for example, in countries that are geared towards exporting hydrogen but have a fossil-dependent power system today. Green hydrogen could still be produced from dedicated renewable facilities, on a local level, effectively having zero emissions, but from a systems perspective not reducing the emissions of the exporting country if the overall power system remains fossil dependent. This would only be likely to occur when there is limited capacity to deploy renewables, and especially for countries where renewable power is still in the early stages (*e.g.* sub-Saharan Africa). In contrast, an opportunity that this situation creates is to use revenues from hydrogen export to develop the domestic renewable industry, contributing to economic and industrial development. This, in turn, can decrease the project risks, improve the business case for hydrogen and make exports even more attractive.

One advantage that global trade introduces is that it is using resources of different quality. Hence, 1 GW of renewable capacity installed in a location with good-quality resources will have a higher annual production than the same 1 GW installed in a location with poor resources. For example, the difference in annual output between North Africa and the north of Germany is almost a factor of two, while the conversion to hydrogen and transport by pipeline would represent efficiency losses lower than 50%. Thus, hydrogen trade does not necessarily mean a higher pace of renewable capacity deployment. It can actually result in a lower capacity requirement if the best renewable sites are used.

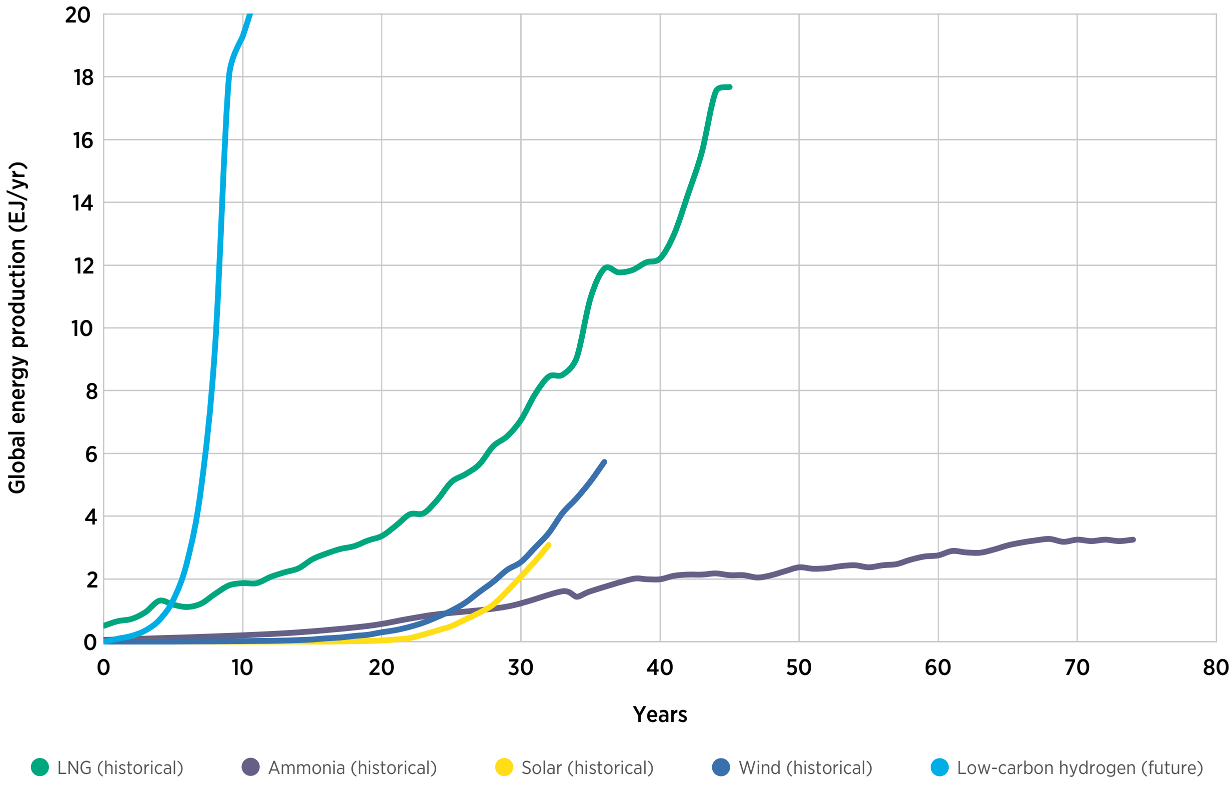
An additional barrier to global trade may be the deployment capacity for electrolysers. Today, global manufacturing capacity is just over 5 GW/year, and the projects announced add up to more than 250 GW. Looking at 2030, annual deployment would need to be around 100 GW/year to be in line with a 1.5°C scenario. Thus, manufacturing would need to rapidly increase. Otherwise, there would be direct competition between domestic production and capacity for export. An additional barrier for deployment is the precious metal content of the electrolysers. This applies specifically to the iridium content of polymer electrolyte membrane electrolysers, while alkaline electrolysers have lower material restrictions (IRENA, 2020b). Although there are already ongoing efforts to reduce these materials, if the electrolyser market ramps up faster than research, this could pose a constraint or expose the electrolysers to a market with limited supply and demand that is subject to drastic changes in commodity prices. The ratio between the highest and lowest price for iridium over the last 20 years is approximately 15 times (EC, 2020). The global current iridium production could only support 3-7.5 GW/year of manufacturing capacity. Strategies like reduction of material use, substitution and recycling, among others, could reduce the materials needed per unit of hydrogen produced (Gavrilova, 2021), but those strategies still need further research and implementation.

The pace of development for the conversion technologies could also pose a challenge. Ammonia today is a 183 Mt/year market, which is equivalent to about 32 $MtH_2$/year, which in turn would be only about 6% of the global hydrogen demand in 2050. The LNG trade market in 2020 was 356 Mt (IGU, 2021b), which in energy terms would be equivalent to about 150 $MtH_2$/year. It took about five to seven decades[40] for each of these technologies to reach these orders of magnitude. Ammonia and LNG can serve as a reference for trade flows since they are globally traded commodities. Other pathways with limited trade of the product, yet with a fast growth, are wind and solar, which have experienced average compound annual growth rates of 22% and

[40] *Haber-Bosch is a much older process (early 20th century), but the largest growth was experienced in the 1950s to 1970s (Erisman et al., 2008).*

39%, respectively, during the last 20 years (BP, 2021). With these growth rates, wind and solar have respectively reached almost 1 600 and 850 TWh of generation in 2020, equivalent to about 48 and 26 $MtH_2$/year. In all these cases, the drastic growth achieved would be eclipsed by the growth needed for low-carbon (*i.e.* green and blue) hydrogen, which would need to grow from almost zero today to 150 $MtH_2$/year by 2030 and 614 $MtH_2$/year by 2050 (see Figure 4.7).

**FIGURE 4.7. Historical growth for various technologies and energy carriers in comparison with low-carbon hydrogen**




Note: Year 0 is 1975 for LNG (already at 14 bcm by then), 1946 for ammonia, 1988 for wind and solar, 2021 for hydrogen. LNG = liquefied natural gas. Low-carbon hydrogen uptake for a 1.5°C scenario.
Source: Brightling (2018); BP (2021); IRENA (2021d); USGS (n.d. b).

## Actions and roadmap to address barriers

The fundamental limitation for renewable deployment is not potential or material constraints, it is how fast the supply chain can scale up to reach the levels needed for a 1.5°C scenario. To achieve this, an acceleration of the capital mobilisation is needed. Annual investments in renewable electricity generation need to almost quadruple, from a historical level of around USD 250 billion to more than USD 1 050 billion on average for the next 10 years (IRENA, 2022a).

The large renewable capacity requirement also means large areas of land need to be dedicated to hydrogen. While in objective terms, this is still, at most, a few percentage points of the total land for most countries (not all), there could still be some resistance for such buildup. Thus, it is important to make sure that local communities where the renewable deployment is taking place are involved throughout the process to create a common understanding and acceptance of the projects. Even better, support from the local communities can be achieved if they see the benefits of the development, for example economic growth, job opportunities or cleaner air.

## 4.7 Infrastructure and regulation

### Barriers hindering trade: Infrastructure

Infrastructure might become the largest hurdle for the liquid hydrogen route. The need for cryogenic temperatures results in high capital costs across the value chain (IRENA, 2022b), which can be 2-2.5 times higher than the total investment needed for ammonia or LOHC. There are virtually no facilities at the right scale for global trade of liquid hydrogen, and the liquefaction plants, storage, bunkering, ships and regasification would need to all be greenfield facilities. However, ammonia and LOHC each have some existing facilities that could be used. Ammonia is already produced, stored and traded in over 130 ports. LOHC can build on the chemical infrastructure for handling around ports. Both, however, would need new infrastructure development. Even if a terminal and storage facilities are available at both ports involved in a trade, the reconversion plant for these pathways could represent 25-35% of the total investment required in the importing and exporting port.[41]

With respect to pipelines, one key challenge is the utilisation during early stages of operation. Pipelines are usually sized for future (larger) flows since they exhibit strong economies of scale, and a single large pipeline will be more cost-effective than building a small pipeline and another small one a few years later. The low utilisation can be worse at the beginning for hydrogen since there is no merchant supply today, and new pipelines go together with new projects for supply and demand. Thus, a pipeline cannot be built in isolation; it requires co-ordination with both supply and demand to assess feasibility. This makes the project more complex but also more expensive since the investment mobilised includes the entire supply chain. This is different from a renewable power project that can only focus on the generation step since the infrastructure and end use are existing facilities with a developed market. For pipelines, the lowest cost is achieved for large pipelines in the order of 122 cm (48 inches), which could carry the equivalent of up to 13.5 GW (at 80 bar). This would be a relatively high hydrogen demand, equivalent to 20 commercial ammonia plants or almost the entire pure hydrogen demand of Northwest Europe today. For pipelines, one additional barrier could be hydrogen leakage and the associated climate impact[42] (Derwent *et al.*, 2006). This can be managed by more frequent monitoring and maintenance through an enhanced pipeline integrity management system.

One option (in regions with existing assets) to reduce the cost is to repurpose part of the natural gas infrastructure to hydrogen. However, there are four key challenges. First, the suitability for hydrogen depends on various conditions (material, operating point, maintenance, age), and it needs a case-by-case assessment. This means that before drafting the repurposing plan, the specific network needs to be assessed. Second, higher pressures make hydrogen embrittlement worse, meaning that the transmission network has higher risks than the distribution network. Despite this, the fraction of the transmission network that can be suitable for transporting hydrogen may still be high. For example, Snam (operator of the gas transmission network in Italy) claims 99% of its pipelines are ready to transport pure hydrogen, of which 70% could transport it with no or limited reduction in maximum operating pressure (Snam, 2021). Third, hydrogen has a different pressure drop profile. The ideal distance between compressors along the pipeline might be different than for gas, while for a repurposed pipeline there are already

[41] *Only considering conversion, reconversion and storage costs (excluding ships and distribution in each country).*

[42] *Hydrogen reacts with $OH^-$, the primary atmospheric oxidant, reducing its concentration. $OH^-$ is the primary sink for all short-lived pollutants including methane. Thus, by reducing the $OH^-$ concentration, hydrogen leakage will increase the lifetime of methane and ozone and hence increase their climate impact. This results in a global warming potential of 11 for hydrogen (Warwick et al., 2022).*

fixed locations for the recompression stations. This introduces either additional costs for setting up new compression stations or higher energy losses due to a suboptimal compression. Fourth, the natural gas demand profile needs to decrease concurrently with the hydrogen demand increase for gas pipelines to become available at the same time and in the same locations as those in which hydrogen users start to arise. This requires an assessment of the network and a match between the decarbonisation plans of the gas network users.

## Barriers hindering trade: Regulation

Regulation is important for at least two aspects of hydrogen trade: infrastructure and market design. For both, regulation needs to be stringent enough to ensure sustainability and alignment with a net-zero future but loose enough to enable experimentation and discovery of the best approach for each domestic context.

One challenge that arises for pipelines is quality standards and aspects like hydrogen purity or allowed level of contaminants in the hydrogen. If hydrogen is intended to be used for fuel cells, the purity is very high, and it is usually reported in numbers of nines achieved (*e.g.* 5.0N purity means five nines or 99.999%). The purity is defined for road transport and stationary applications in ISO 14687:2019, but not for transmission pipelines. While in the EU there are already efforts to develop a common EU network, integration with neighbouring countries such as Algeria, Libya, Morocco, Tunisia or Ukraine is still lacking. Similarly, other parts of the world that could develop a regional network, such as Latin America, currently have no ongoing efforts to define these quality standards or, more broadly, to develop the infrastructure.

Another aspect of regulation of pipelines is the operators of the network. Hydrogen is replacing natural gas for some applications (*e.g.* power) and can be clustered under "low-carbon" gases, together with biomethane and synthetic methane. At the same time, since one option for pipelines is to repurpose the natural gas network, one natural choice for operators could be to have the same gas network operators for the new hydrogen network. In the case of Europe, a hydrogen and decarbonised gas package was proposed in December 2021 (EC, 2021b), providing clear rules on ownership of hydrogen infrastructure (pipelines, storage, terminals), on open access, on tariffs, and on engagement in terms of planning and developing the infrastructure. The package also considers the formation of a new European Network of Network Operators for Hydrogen, with many of the rules governing the gas network carrying over to hydrogen. A similar issue of ownership and operation arises for LNG terminals, with the difference that LNG facilities would require major modifications and cannot directly be used for hydrogen (as natural gas pipelines).

While the safety challenges for hydrogen are well understood from its use in industrial environments, there needs to be a broader dissemination of these practices beyond industry as hydrogen transitions to being used as an energy carrier and used across a new range of applications. These safety challenges apply not only to hydrogen but to its derivatives as well. For example, as identified in this report, ammonia is the most attractive carrier for shipping, but this potentially also implies transitioning to using ammonia as fuel as well to reduce overall GHG emissions. This practice requires reviewing the existing safety guidelines and adapting those to handle a new commodity as a fuel (since handling practices for its use as cargo are already widespread). This also applies to pipelines that have so far been managed by industrial gas manufacturers; future hydrogen networks will have new operators that need to develop the corresponding safety guidelines.

## Actions and roadmap to address barriers

Regulation of the infrastructure is necessary when a single entity controls a large share of the network and there is a risk of abuse of market power either for pricing or tariff-setting strategies or restricted access to the network. There are some additional principles to consider for the operation of the network (ACER, 2021):

- Operation by a regulated entity that remains neutral.
- A clear governance structure for monitoring and oversight of the regulated entity by a regulatory authority.
- Transparency that promotes efficient network investments.
- Consumer protection rules (in case households are users of the network).
- Equal access to all parties without discrimination (third-party access).
- Decoupling ("unbundling") of the activities between networks (horizontal) and across the hydrogen value chain (vertical). This prevents a single entity from controlling large parts of the supply chain or network and from having a dominant position.

In the process of introducing regulation, there is a fine balance to strike. It should be strict enough to ensure that there is no abuse of market power and that there is a fair competition, but it should be loose enough to avoid being overly restrictive and hindering the potential hydrogen deployment. This balance will change over time as technology develops and experience builds up. Thus, regulation should go together with frequent review cycles to adapt it to both market and infrastructure developments. At the same time, this process of adaptation can be accelerated by using regulatory sandboxes that provide flexibility in testing different configurations and arrangements under controlled conditions to develop understanding of the consequences of certain schemes before introducing them across the entire system.

Regulation can also be bound to milestones of the system. Such a milestone could be, for example, capacity of the network, number of suppliers or users, or annual flows. This would combine the clarity and long-term certainty needed by investors with an adaptable regulation.

In regions like North America, Europe and Eastern China, there are extensive natural gas networks that can be repurposed. The expansion planning of the hydrogen network should go together with the planning of the natural gas network to enable a temporal and spatial match between the hydrogen projects being proposed (potentially requiring access to transport capacity) and the natural gas flows that dwindle as methane is displaced by other commodities.

Like other commodities, regulation for hydrogen extends beyond fair competition and infrastructure access to cover aspects like energy security and security of supply. Part of the infrastructure is the storage, and the regulation of these assets will affect the capacity to deliver for the network. Similarly, if the storage facilities are in parts of the network that have restricted capacity, their full value might not be used. At the same time, when comparing hydrogen with natural gas, an advantage that hydrogen has is that production is expected to be more decentralised, with multiple suppliers connected to the network. This decreases the dependence on a few suppliers, improving the overall security of supply and facilitating regulation in this respect.

Regulation goes together with certification, especially when commodities with different production pathways are mixed. In the case of pipelines, there is no difference for transport (*e.g.* pressure drop) for molecules with different origins. However, such a difference is important for the end users, so hydrogen transport should go together with the certificates that attest the environmental impact and characteristics of its production. When broadening the scope to hydrogen derivatives, renewable hydrogen could be mixed with carbon-intensive commodities, so regulation of these cases should also be considered.

Part of the regulation is also targeted towards cost recovery and the options discussed in the actions of Section 4.5. One option to consider as default is that the costs of the network should be borne by its users. This means that for repurposed natural gas assets, the asset base should be transferred from natural gas operators to hydrogen operators. Even when the operators are the same, the accounting should be separate for cost allocation purposes and to avoid cross-subsidies. However, allowing cross-subsidies could also facilitate investment during early stages of hydrogen infrastructure development (EC *et al.*, 2021c). One example of regulation of returns comes from Germany, where in November 2021, the Government passed a regulation to set the returns of new hydrogen pipelines to 9% (versus 4.6% for natural gas pipelines) (BNEF, 2022). This was done to promote the development of the new grid. The regulated return applies to both transmission and distribution pipelines. It also applies to repurposed gas pipelines, but with a lower return of 7.73%. The rate of return applies to the equity share of the investment and to all the costs that are not covered by other subsidies (*e.g.* IPCEI funding).

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