Hydrogen Council

McKinsey & Company

Global Hydrogen Flows - 2023 Update

Considerations for evolving global hydrogen trade

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http://www.hydrogencouncil.com

Introduction

Hydrogen and its derivatives will play a central role in decarbonization and global trade will be critical for driving uptake. This was the key finding of *Global Hydrogen Flows*, a joint report of the Hydrogen Council and McKinsey & Company published in 2022. It highlighted the inability of major future hydrogen demand regions, including Europe, Japan, and South Korea, to meet all their demand at affordable costs. Other regions, the report showed, could potentially have excess low-cost supply.

Yet the outlook for hydrogen is far from fixed. The hydrogen industry is constantly adapting to a rapidly evolving regulatory framework, shifts in global policy, geopolitical forces, new technologies, and ongoing learning from project implementation. This 2023 summary report revisits the findings of the 2022 *Global Hydrogen Flows* report to account for these and other changes—and assesses how global hydrogen trade flows could evolve.[1]

About the analysis

The results presented in this 2023 summary report are based on a more detailed document, showing the outputs from an advanced analytics optimization model. This software balances supply and demand across all regions, multiple carriers, and end products.

The Global Hydrogen Trade Flows Model optimizes across 1.5 million trade routes and multiple demand scenarios

Inputs

- Demand forecasts
- Diversification and security of supply constraints
- Production costs
- Production limits
- Transport costs

Optimization of production and trade flows

- **98** pipeline directions
- **62** market regions
- **9** largest countries with a subcountry split
- **8** production source categories
- **5** end products
- **4** full optimization years: 2025, 2030, 2040, 2050
- **4** hydrogen carriers and a carrier for green steel

Outputs

- Capex forecasts
- Country productiton forecasts
- Destination cost curves
- Flow volumes by carrier
- Marginal cost forecast
- Scenario analysis

Source: Hydrogen Council, McKinsey Global Hydrogen Flow Model

[1] Unless otherwise stated, all data and analysis in this summary report are based on data provided by the Global Hydrogen Flows 2023 dataset of the Hydrogen Council and McKinsey & Company, drawing on data provided by McKinsey & Company.

Key messages from this update

Despite the existing positive and growing momentum on hydrogen uptake *(refer to Hydrogen Insights 2023)*, it is also becoming clear that the current growth rate is not strong enough compared to what is required for the net-zero trajectory, at least not by 2030. Acknowledging the critical role hydrogen has to play for the world to decarbonize by 2050, there is a need and urgency to step up efforts that address challenges and unlock investments.

Estimates of the levelized cost of hydrogen (LCOH) for renewable hydrogen are between 30 and 65 percent higher than those in the October 2022 report. The revised estimates reflect higher electrolyzer capital expenditure as well as renewable costs and factor in elements that may influence individual countries' investment attractiveness.

The 2023 analysis considers demand and trade in a scenario called Further Acceleration (FA), one where the energy transition is accelerated compared to today's pace but the world still fails to reach below the 1.5°C temperature target. Under this scenario, demand for clean hydrogen (both low-carbon and renewable) could reach over 40 million tons per annum (MTPA) by 2030. To feed this demand, nearly 20 MTPA could be transported long distances mostly via pipelines or shipments of clean ammonia as a fuel, hydrogen carrier, and replacing grey ammonia. By 2050, clean hydrogen demand grows to 375 MTPA and around 200 MTPA could be transported long distances. By then, pipelines could account for around 40 percent of long-distance transportation, synthetic kerosene and ammonia another 20 percent each, shipped hydrogen (either via ammonia, LOHC, or LH2) 10 percent, with methanol and green steel accounting for 5 percent each.

30 to 65%

Increase in renewable hydrogen LCOH compared to 2022 report

20 MT

Hydrogen transported over long distances by 2030 out of 40 MT in Further Acceleration scenario

200 MT

Hydrogen transported over long distances by 2050 out of 375 MT in Further Acceleration scenario

By 2030, evolving production cost profiles together with the introduction of production incentives in some markets could result in a global cost curve with a 15x cost differential between the lowest and highest cost regions. With costs reaching below $1/kg due to supply incentives such as the Inflation Reduction Act and over $5/kg at the upper end. This could lead to trade arbitrage opportunities. By 2050, the global cost curve is expected to flatten to a 2.5x cost differential as incentives expire and renewable costs reduce with the most competitive regions at around $1.5/kg and high-cost regions sitting at around $3.5/kg.

Trade reduces the cost of carbon abatement, when compared to a scenario where global trade is limited. Indeed, the need to produce higher cost hydrogen (with trade being limited) would result in total investment requirements of $12 trillion, by 2050. By contrast, in a scenario in which international hydrogen trade can develop, total hydrogen-related investments would amount to approximately $8 trillion by 2050, representing a $4 trillion cost savings. To facilitate long-distance transportation of hydrogen and derivatives, around $70 billion investments would be required per year in transport, conversion, and reconversion.

15X
Cost difference in 2030 between highest and lowest cost production regions

$8 TN
Total hydrogen related investments required by 2050

$70 BN
Annual investments required per year by 2050 in trade related investments

50%
Reduction in total hydrogen investments unlocked through trade

How the landscape has changed

The past 12 months have seen some major changes in expected demand, production conditions, and regulations.

Hydrogen demand growth projections remain robust but tempered by slower decarbonization expectations

The reference case of the 2022 *Global Hydrogen Flows* report was called “Efficient Decarbonization” and reflected the Hydrogen Council’s net-zero scenario. This set out the full potential for hydrogen to decarbonize energy systems with few longer-term constraints on trade, ensuring that the 2050 climate change requirements could be met in an economically efficient way. Demand in this scenario reached 70 MTPA of clean hydrogen by 2030 out of a total of 140 MTPA, and 660 MTPA of clean hydrogen by 2050. The report also presented three bespoke alternative scenarios, including one with a lower demand case called Delayed Transition where demand reached 100 MTPA by 2030 (40 MTPA of which was clean hydrogen) and 400 MTPA by 2050.

Since the report was released, it has become clearer still that the world is not on a net-zero trajectory, at least not by 2030. For instance, in June 2023, as part of McKinsey’s Global Energy Perspective, 152 international energy experts and executives were asked what decarbonization trajectory they believed the world is on. This was then compared to a range of 2023 McKinsey energy transition scenarios. The majority picked a trajectory that represents a scenario known as Further Acceleration (FA). This is one where the energy transition is accelerated but financial and technological constraints remain so that global net zero is not reached by 2050, resulting in a 1.9°C global temperature increase. To account for the consensus view on climate change trajectory, the Global Hydrogen Trade Flow results in this summary report have been updated using the FA scenario.

The net-zero demand scenario remains the Hydrogen Council’s reference scenario as it underscores the critical role that hydrogen has to play for the world to decarbonize by 2050. However, the dampened outlook reflects a reality that cannot be ignored—despite positive trends, both producers and would-be users of hydrogen continue to face challenges, from increasing costs to technological uncertainties to a lack of coherent and stable regulation, including a global price on carbon, that impact the pace and buildout of the hydrogen economy. This serves as a stark reminder that, for hydrogen to achieve its full potential, there is a need to step up efforts that address challenges and unlock investments.

Renewable hydrogen will play an important role, despite a higher cost outlook

The 2023 analysis includes a detailed bottom-up assessment of the development costs of large-scale renewable hydrogen projects undergoing front-end engineering design (FEED) studies.[2] This approach considers not just equipment costs but also includes a thorough review of the balance of plant (BoP), as well as engineering, procurement, and construction (EPC) costs. The assessment found that the LCOH for renewable hydrogen is between 30 and 65 percent higher in 2023 when compared to estimates from 2022. The increase in LCOH is driven by higher capex, financing, and renewables costs, as well as the broader inclusion of additional costs such as EPC. A large portion of the cost increase is from the higher BoP and other developer costs, as found by McKinsey Capital Analytics and McKinsey Hydrogen Insights when assessing electrolysis construction projects. To soften the impact of higher plant capex, the electrolyzer size can be decreased or load factor increased by swapping lower-cost solar with low-load factors, with setups that yield higher load factors such as wind and hydropower.

Despite the higher cost outlook, the analysis points to renewable hydrogen largely maintaining its market share compared to low-carbon hydrogen from gas—for reasons potentially ranging from a focus on products derived from renewables to new incentives and direct support. By 2050, out of 375 MTPA of total clean hydrogen demand, the forecast is 265 MTPA renewable and 110 MTPA low carbon reflecting a 70:30 split. (See sidebar, "Renewable hydrogen maintains its market share").

Cost and technology uncertainties persist in low-carbon hydrogen production

Natural gas prices have seen sustained volatility since the initial report was released in 2022. At the time of writing, natural gas futures in Asia and Europe remain elevated and have been used to guide the updated view to 2030 as gas producers may favor expanding exports of natural gas. Beyond 2030, the natural gas price outlook is based on the supply-demand balance expectations and is differentiated by region. Under the FA scenario, gas demand and global gas prices decline over time, making low-carbon hydrogen production more competitive. At the same time, the trajectory of the natural gas demand decline is slower than under the net-zero scenario, increasing the price of both natural gas and low-carbon hydrogen ($0.10 to 0.20 per kg) relative to the net-zero scenario projections.[3] Capex has also risen for low-carbon hydrogen, but this has a far more limited impact on the cost of production, given that costs are mostly operating expenditure (opex) driven. Higher electrolyzer capex favors low-carbon hydrogen production and—assuming CCS can be scaled up fast enough—low-carbon hydrogen could account for 45 percent of hydrogen production compared to the base case of 25 to 30 percent and reach up to 65 percent of long-distance traded volumes.

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[2] Renewable hydrogen is produced by electrolysis of water using renewable energy, while low-carbon hydrogen is hydrogen produced from natural gas in a facility that uses carbon capture and storage (CCS) to sequester greenhouse gas emissions arising from production; McKinsey Capital Analytics and McKinsey Hydrogen Insights.
[3] *Global energy perspective* 2023, McKinsey, October 2023.

Policies and production incentives could reduce costs, potentially boosting production and exports

Policies such as the Inflation Reduction Act (IRA) in the United States and the Clean Hydrogen Investment Tax Credit (ITC) in Canada have been factored into the analysis.[4] For the United States, the new estimates incorporate a production tax credit (PTC) of $3 per kg for renewable hydrogen over the first ten years of a project's duration, with additional credits available on renewable electricity generation. For low-carbon hydrogen, producers can select either a PTC of up to $3.00 per kg over the first ten years or $85 per tCO_2 for CCS in the first 12 years.[5] For Canada, the update includes an ITC of 40 percent of the renewable hydrogen plant capex and 30 percent of the renewable capex, as well as 40 percent of the low-carbon hydrogen plant capex. In combination, these measures impact positions on the cost curve of hydrogen until the 2030s.

Demand mandates for renewable hydrogen from the Renewable Energy Directive (RED III) have been incorporated into the modeling for Europe.[6] This includes the mandate for 42 percent of hydrogen products consumed by industry (excluding refining) to be renewable by 2030 with the target increasing to 60 percent by 2035.

Renewable hydrogen maintains its market share

Estimates of LCOH have been revised in our 2023 update, as compared to the 2022 report. However, the update indicates that renewable hydrogen largely maintains its market share compared to low-carbon hydrogen from gas. This can be explained by multiple factors, including:

- *The drive to increase the use of products derived from renewables.* Some regions, such as Europe, have regulations in place that require renewable hydrogen and its derivatives to meet a portion of demand.[1]

- *New incentives and direct support.* New incentives for renewable hydrogen are emerging, boosting short-term economics.[2]

- *CCS progress.* The latest pipeline of CCS projects has been used to guide the level of low-carbon hydrogen production to 2030 with scale up factors applied beyond this.

- *Higher gas prices.* In the Further Acceleration scenario that was explored in McKinsey's *Global Energy Perspective*, the energy transition is accelerated but not enough to meet global net zero in 2050. Higher gas prices could cause some reduction in the competitiveness of gas-based, low-carbon hydrogen, with existing exporters monetizing gas for longer via pipelines and liquified natural gas (LNG) exports.

[1] Global hydrogen flows, McKinsey and the Hydrogen Council, October 5, 2022; "Renewable Energy: Council adopts new rules," Council of the EU, October 9, 2023.
[2] "The Inflation Reduction Act: Here's what's in it," McKinsey, October 24, 2022; "Consultation on the clean hydrogen investment tax credit," Government of Canada, June 2, 2023.

[4] "The Inflation Reduction Act: Here's what's in it," McKinsey, October 24, 2022; "Consultation on the clean hydrogen investment tax credit," Government of Canada, June 2, 2023.
[5] "H.R.5376 – Inflation Reduction Act of 2022," Congress.gov.
[6] "Renewable Energy Directive," European Commission, March 30, 2023.

Three key factors could determine the competitiveness of hydrogen production

Hydrogen can be produced almost anywhere, but competitiveness varies across regions and markets—even before incentives are considered. Commercial supply potential, and consequently trade potential, can be influenced by three main factors.

The first factor is the LCOH. For renewable hydrogen, LCOH is primarily determined by local renewable costs, the size of the renewable potential (for example, not all of the best locations will be available) and electrolyzer utilization, while for low-carbon hydrogen it is determined by the local costs and availability of methane and CCS, as well as emissions pricing. The 2022 findings have been updated to reflect the latest data relating to these parameters, and now also consider the impact on LCOH from North American incentives that are currently in place. The higher electrolyzer costs now considered have two impacts on the cost curve. Firstly, making low-carbon hydrogen production sources relatively more competitive. Secondly, it increases the attractiveness of windier locations for renewable hydrogen projects as in turn this leads to higher electrolyzer utilization.

The second factor is the pace of CCS deployment, which determines the ability to accelerate low-carbon hydrogen production. The low-carbon hydrogen project pipeline to 2030 included in the analysis reflects the current pace of CCS deployment. CCS could be considered a more important factor in determining the commercial potential of low-carbon hydrogen than gas prices.

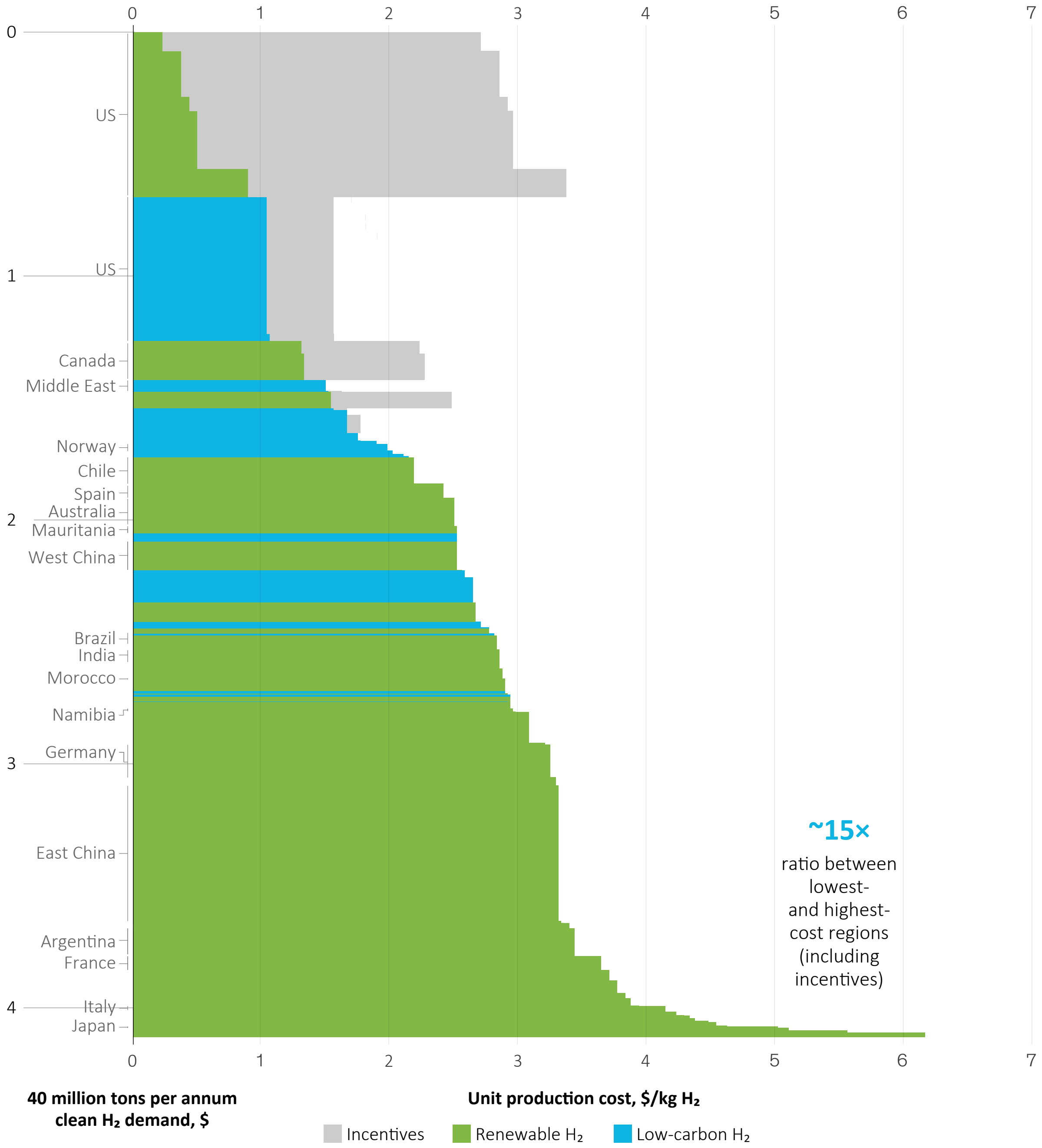
The third factor spans elements that may influence a region's investment attractiveness. These include market efficiency, industrial capability, workforce availability, and local public acceptance of building new infrastructure. To reflect these factors, the updated analysis considers regional premiums which influence the weighted average cost of capital by between 5 and 14 percent. If these premiums are not included, projections of renewable hydrogen production would be driven solely by renewable energy system (RES) quality.

The potential net impact of these and other factors on clean hydrogen production costs is demonstrated on the 2030 supply cost curve (Exhibit 1).

Exhibit 1

50 percent of global H_2 production is under \$2.5/kg H_2

Global clean H_2 production cost curve,[1] Further Acceleration scenario, 2030



[1]Countries are representative of producers rather then exhaustive.
Source: Hydrogen Council, McKinsey Global Hydrogen Flow Model

Long-distance transportation of hydrogen and derivatives would reduce overall investment requirements

The geographic location of the main demand centres for clean hydrogen does not always coincide with the locations that provide the conditions to produce clean hydrogen in favorable conditions. This opens potential trade opportunities between countries that have (potential) excess clean hydrogen production capacity at attractive cost, and countries needing to import hydrogen.

Future trade and transportation in hydrogen and its derivatives will be determined by a host of factors including production costs, the types of products being transported, and other process inputs.

Some high-demand areas—such as Japan, South Korea, and parts of Europe—will likely have limited excess power available for hydrogen production due to the requirement for broader decarbonization of the power system. Meanwhile, other regions will likely have excess production potential above local demand, such as South America and the Middle East.

By 2050, several countries could be producing hydrogen at close to \$1.50 per kg, with the lowest end of the production costs potentially being close to \$1.20 per kg. On the other end of the spectrum, countries with limited low-cost clean energy potential would see domestically produced hydrogen being significantly more expensive, typically above \$3.50 per kg.

Where supply sources are available locally, this local production would in many cases be more cost-effective than supply from distant production locations, even if these are lower cost. This is because long-distance hydrogen transport requires conversion to an intermediary at the point of production and then reconversion at the point of use, increasing costs due to hydrogen losses and requirements for other inputs such as electricity. Long-distance transport of hydrogen via intermediaries will thus likely only occur when there is no other option, for example, where demand centers simply do not have the resources to produce hydrogen themselves.

Transportation costs of derivatives such as ammonia and synthetic kerosene are, however, small relative to the overall cost of the products, due to higher volumetric densities. The relatively low transport costs could potentially make long-distance trade in derivatives from lower-cost centers competitive with local supplies in high-cost markets.

Accessibility to high volumes of clean CO_2, either from biogenic sources or via direct air capture, could significantly improve the competitiveness of synthetic fuels (synfuels) and methanol production in some locations and hence the ability to trade in these products. Brazil, Canada, China, Indonesia, and the United States represent more than 60 percent of the global clean CO_2 available. This is expected to remain the case until the 2040s when the cost of direct air capture reduces to compete with biogenic sources.[7] Access to DR-grade iron ore is another determining factor that will likely drive hydrogen production for low-carbon and green steel in areas such as Brazil and Sweden. Even in countries with no iron ore resources, a lower LCOH could also drive iron ore imports and hot briquetted iron (HBI) production for domestic and export use.

Total hydrogen-related investments under the FA scenario could amount to approximately $8 trillion by 2050. To facilitate long-distance transportation of hydrogen and derivatives under this scenario, annual investment of around $70 billion in transport, conversion, and reconversion infrastructure would potentially be required each year by 2050. This would cover the cost of building and operating conversion and reconversion infrastructure, more than 500 ships and carriers, as well as the pipelines needed to transport over 200 MTPA of hydrogen and hydrogen derivatives over long distances. These investments could save some $4 trillion in total investment costs when compared to a scenario where global trade is limited. This is thanks to the ability to produce hydrogen and derivatives in lower cost regions and transport it to high-cost production regions. Note that even greater overall savings can be achieved if investments would be consistent with the net-zero scenario. Under a net-zero scenario trade related investments would be double: $140 billion by 2050, to cover the cost of more than 1,100 ships and carriers to transport hydrogen derivatives and pipelines to move over 200 MTPA of hydrogen and this would save over $6 trillion in investment costs across the value chain.

[7] McKinsey analysis drawing on inputs provided by McKinsey's Energy Solutions team.

The continued evolution of global trade routes

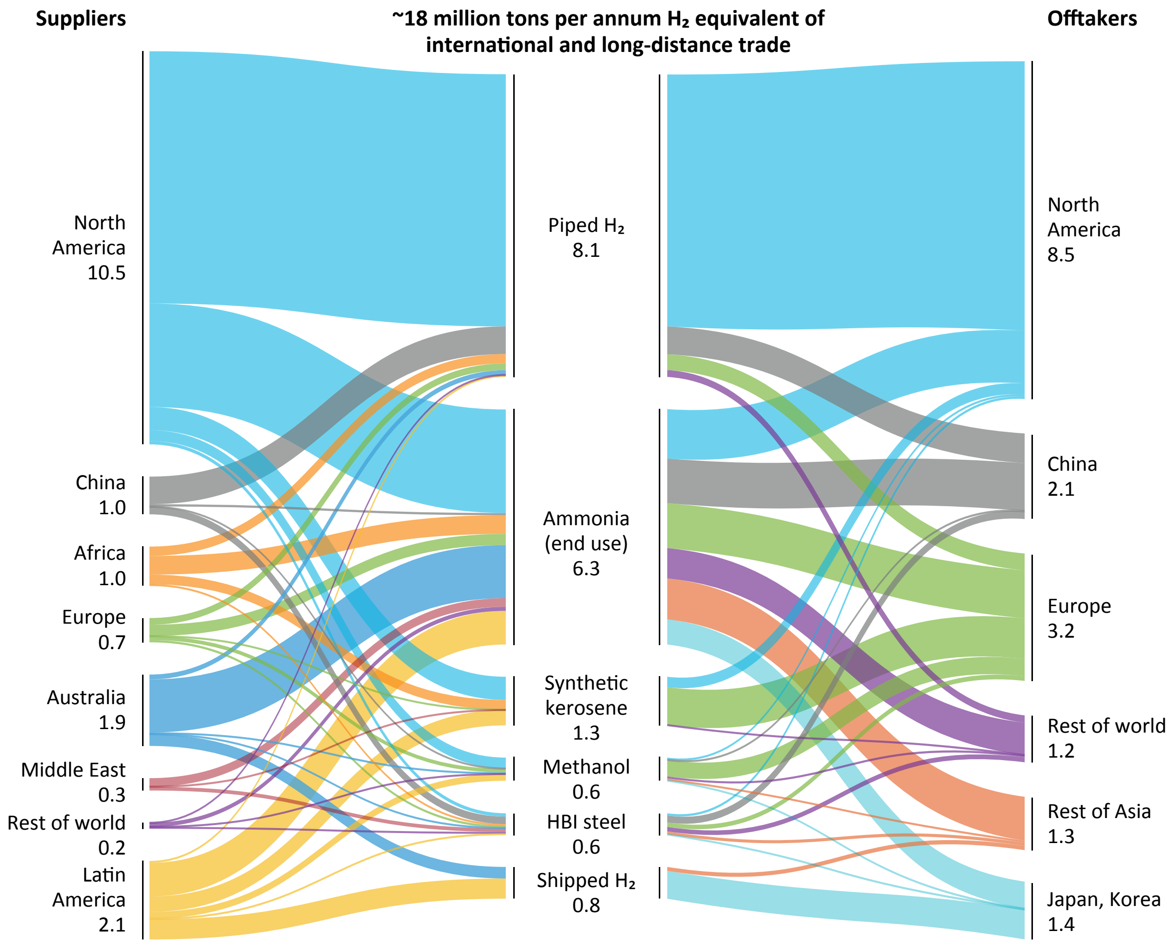
Different regions are likely to drive hydrogen and derivatives trade at different points in time. Canada and the United States are expected to initially both be net hydrogen exporters, due to a ramp up of production supported by the IRA in the United States and the ITC in Canada, resulting in production exceeding domestic demand. These instruments could encourage the early adoption and scale-up of production, with export trade a consequence of supply exceeding demand. Further, both Canada and the United States benefit from vast reserves of low-cost natural gas and attractive wind resources, enabling them to meet large domestic demand and export simultaneously. Australia could export nearly 2 MTPA of hydrogen equivalent—mostly ammonia—primarily to Asia by 2030 (Exhibit 2).

In the coming decade, the long-distance transport of hydrogen could scale to nearly 20 MTPA, mostly via long-distance pipeline transportation in China and North America, with some international pipelines in Europe. Hydrogen and ammonia could be the main clean products traded over long-distance routes by 2030, through pipelines and by ships, respectively. Both could leverage existing infrastructure. By 2030, long-distance transport could reach 18 MTPA of hydrogen equivalent with nearly 80 percent of this being transported via pipeline or as clean ammonia as an end product.

Exhibit 2

North America is expected to lead supply, demand, and international trade of clean hydrogen and derivatives by 2023

2030 global clean H_2 long-distance flows,[1] Further Acceleration scenario



[1] All international trade, including trade between split regions, most notably East and West China, including 65 percent of domestic production in Australia, Brazil, Canada, Russia, United States, and West China.
Source: Hydrogen Council, McKinsey Global Hydrogen Flow Model

The Nordics and Iberia are also expected to become exporters of piped clean hydrogen to other European regions, with further export opportunities for methanol, e-kerosene, and HBI or direct reduced iron (DRI). North Africa could also export low-carbon and renewable hydrogen to Europe. There could also be additional exports of ammonia from Southern Africa. China and India could be self-sufficient for hydrogen demand, meeting their hydrogen demand through domestic production but potentially transported over long distances via domestic pipelines. Local production could be supplemented by some seaborne imports of derivatives, such as low-carbon ammonia from the Middle East but they may also export some derivatives depending on the trajectory of future costs.

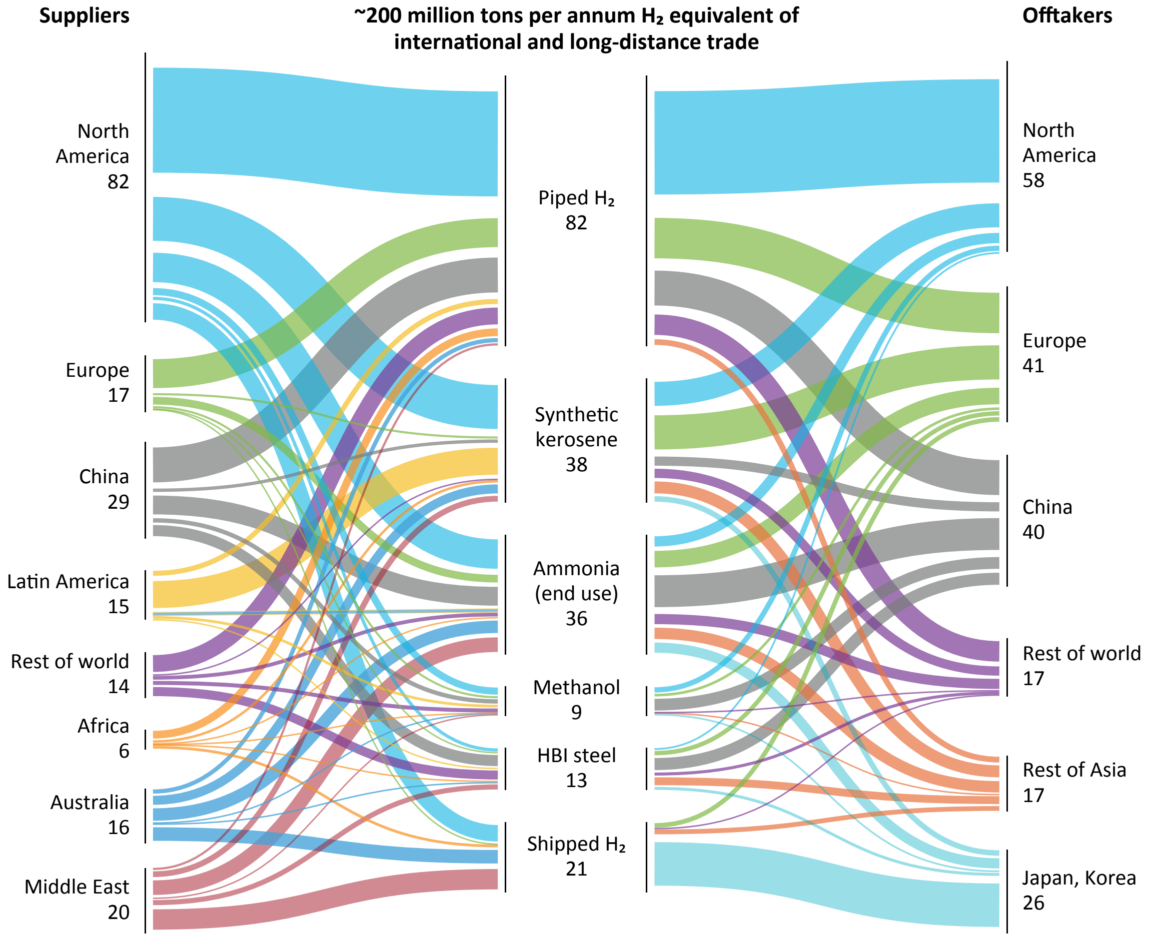
The Middle East is expected to be an exporting region of clean hydrogen. The region has a large reserve of low-cost gas, competitive renewables, and close proximity to South and Southeast Asia—allowing for convenient trade routes. Exports could scale, particularly post 2030, as additional gas production and CCS scale-up facilitate low-carbon hydrogen production, complemented by the growth in renewables. South America is expected to be a key exporter of derivatives, with privileged access to competitive renewables, biogenic CO_2, and HBI-grade iron ore. Exports in 2030 could exceed 2 MTPA of HBI and ammonia for hydrogen reconversion.

From 2030 to 2040, long-distance transportation could reach some 100 MTPA, a fivefold increase over the decade. This growth will likely be driven by increasing demand for synthetic kerosene and clean ammonia and, to a lesser extent, by higher demand for renewable methanol in Asia. Both developments would drive shipped exports from Australia, the Middle East, and North America. The 2030s could also see the growth of selected large-scale international piped exports—from the Nordics to Europe, for example. Long-distance domestic pipeline transportation in China, India, and the United States could also scale. Markets such as Japan, Singapore, and South Korea, may continue to be supply-constrained and could scale shipped hydrogen imports via carriers (such as ammonia, liquid organic hydrogen carriers, e-methane, or liquified hydrogen) to meet the growing demand (Exhibit 3).

Exhibit 3

Clean hydrogen and derivatives trade is expected to become truly mature by 2050, with multiple exports and imports hubs

2050 global clean H_2 long-distance flows,[1] Further Acceleration scenario



[1] All international trade, including trade between split regions, most notably East and West China, including 65% of domestic production of Australia, Brazil, Canada, Russia, US, and West China.
Source: Hydrogen Council, McKinsey Global Hydrogen Flow Model

Between 2040 and 2050, demand is expected to be concentrated in China, Europe, India, Japan, North America, and South Korea. Only a few regions, such as North America, could be near self-sufficient. The other regions will need to meet their demand through imports, resulting in long-distance trade potentially reaching 200 MTPA, representing over 50 percent of global hydrogen demand. By 2050, trade links could be more diverse in products, sources, and destinations. For example, exports from Latin America could grow to 15 MTPA by 2050, mostly of synthetic kerosene exports to major markets in Europe and Asia, driven by low costs and local availability of clean CO_2. Export volumes from Australia could also grow to over 15 MTPA by that time, largely driven by its low-cost renewable resources utilizing both wind and solar and geographical proximity to import-dependent markets such as East and Southeast Asia.

Key implications from the changes since the 2022 report

Hydrogen has a key role to play in a world that aims to be fully decarbonized by 2050. To achieve this, efforts and investments needed to build hydrogen ecosystems, as well as to implement the necessary enabling factors would need to be stepped up urgently. The updated analysis presented in this 2023 summary report highlights that long-distance and international transportation will be critical and instrumental to facilitate hydrogen uptake, even though the cost estimates are higher than the 2022 report indicated. The following five key changes since the 2022 report may have strategic implications for industry stakeholders across the hydrogen value chain.

Regulatory policies may impact trade flows

Policies on the supply (IRA and ITC) and demand (RED III) sides have been enacted over the past 12 months, with implications for trade flows. Both production incentives (such as those introduced in Canada, Europe, and the United States) and the available natural resources—whether excess natural gas or renewables—could help developers of clean hydrogen to improve their economics and position on the global cost curve. The regulations introduced in Europe that specify targets for renewable hydrogen uptake in Europe are an effort to stimulate demand and could present opportunities for producers and traders to secure offtake contracts in the region.

Low-carbon hydrogen remains competitive even with higher gas prices

Sensitivity analysis has shown low-carbon hydrogen to remain cost competitive even under the assumptions of higher gas prices. The steady share of low-carbon hydrogen in the future hydrogen mix across different natural gas price scenarios could be seen as an encouraging sign for producers of low-carbon hydrogen in low-cost gas locations if coupled with expanding CCS capacity such as in Norway, the United States, the Middle East, and North Africa.

The rate of CCS deployment could be a bottleneck to low-carbon hydrogen production

The rate of deployment of the cheapest current form of clean hydrogen—low-carbon—could be set by the pace of the CCS project rollout, which continues to be slow in 2023. The ability to de-bottleneck the development of CCS projects over the next decade could help to support the development of at-scale, low-carbon hydrogen projects. Measures could include value chain coordination and regulatory frameworks to reduce risk and enhance revenue streams.

Opportunities exist to reduce production costs of renewable hydrogen

Capex estimates for renewable hydrogen plants have increased by 80 to 100 percent since the 2022 estimates, as costs beyond electrolyzers (such as EPC and BoP) have been included more comprehensively in the models. Capex capabilities, such as the ability to reduce EPC costs and minimize WACC, have become more important than ever for renewable hydrogen developers. Access to steadier sources of power supply, such as hydropower or onshore wind, could help producers of renewable hydrogen to mitigate higher capex by maximizing output for a given electrolyzer capacity.

Local availability of biogenic CO_2 can be advantageous

The costs and complexity of biogenic CO_2 transportation have been revised upward from 2022 estimates, making domestic supply increasingly important. Access to local, low-cost biogenic CO_2, such as from large-scale bioethanol plants, will likely be beneficial for producers of clean methanol and synthetic kerosene.

The expected global demand increase for hydrogen and its derivatives will likely foster trade, accelerating the transition to a hydrogen economy. The updated analysis presented here could help industry stakeholders to develop strategies for global hydrogen trade.