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CAN DEMAND FOR GREEN FERTILISER ACCELERATE ELECTROLYTIC HYDROGEN SUPPLY?

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Executive summary

This brief explores whether targeted supply- and demand-side policies could support the scale-up and commercialisation of electrolytic hydrogen production. Using a new model that simulates the diffusion of different hydrogen production technologies (FTT:H2), it explores the impacts of a global mandate for green ammonia for use in fertilisers and a global carbon price on hydrogen production. Our key findings are:

- Current hydrogen policies are insufficient to kickstart the large-scale deployment of electrolytic hydrogen production globally.
- Electrolytic hydrogen can compete with fossil-fuelled hydrogen when a mandate and carbon price are implemented together (though this varies heavily from region to region). We model a global carbon price levied on hydrogen production that starts at zero in 2025 and increases linearly to $200/t$CO_2$ in 2050. The cost of fossil-fuelled hydrogen reaches the same level as electrolytic hydrogen with dedicated renewables in some world regions in 2050 and when this is combined with a mandate on electrolytic hydrogen for use in ammonia production, cost parity is achieved earlier due to faster learning-by-doing effects.
- Mandates on electrolytic hydrogen for fertiliser production are effective at kick starting off-grid electrolytic hydrogen production in regions with cheap renewable resources. While these regions can produce electrolytic hydrogen that is price competitive with fossil-fuelled hydrogen, it will require large-scale deployment of dedicated renewable electricity generation.

- Access to affordable renewable energy resources is a greater driver of reducing electrolytic production costs than the effects of learning-by-doing in reducing electrolyser equipment costs. In most regions electrolytic hydrogen produced from dedicated renewables will be more cost-effective than hydrogen produced from grid-connected electricity.

- In Brazil, electrolytic hydrogen is already cost competitive with domestic fossil-fuelled hydrogen under current policies. Our modelling shows that policy support could lead to the country becoming self-sufficient in nitrogen-based fertilisers, reducing import dependency and even becoming a regional exporter of low-carbon hydrogen products. However, our modelling does not fully reflect other policy consideration or potential in-country challenges to deploying electrolytic hydrogen production, including the significant expansion of new renewables generation and investments required.

Our chosen policy scenarios are more stringent than current policies, but are not aligned with specific global emissions targets or national targets for hydrogen production capacity. Our modelling results show that additional policy support is needed to kickstart the market for electrolytic hydrogen production. A carbon price alone is unlikely to be sufficient to phase out the production of high-carbon hydrogen; strong demand-side policies will also be required, such as mandates in specific end-use sectors.

The opportunities and challenges of low-carbon hydrogen

Countries around the world have recognised the role that low-carbon hydrogen could play in the energy transition, alongside greater electrification, efficiency and power sector decarbonisation. IEA modelling shows that hydrogen could represent 4% of total global energy consumption by 2050 under a net zero scenario.[1] Low-carbon hydrogen can replace high-carbon hydrogen and derivatives including ammonia, which is currently used as a feedstock for the chemical industry, including to produce fertilisers. It can also be used to replace fossil fuels to decarbonise industry, transport and power generation.[2]

Nearly all hydrogen produced today is high-carbon (so called fossil-fuelled or 'grey hydrogen') ,without any carbon capture technology. There are a number of technology pathways—each at different stages of maturity and scale—for producing low- and zero-carbon hydrogen. This study focuses on two: producing hydrogen from natural gas combined with carbon capture, utilisation and storage technology (so-called CCUS-enabled or 'blue' hydrogen), and producing hydrogen from water, using an electrolyser powered by electricity (so-called electrolytic or 'green' hydrogen). **This brief explores different policy levers for kick-starting the market for electrolytic hydrogen, which is a key technology pathway for producing zero-carbon hydrogen.**[3]

Though many countries have signalled high ambitions for hydrogen deployment, the current policy landscape is still nascent and focuses more on supporting the supply than use.[4] However, only 4% of new electrolytic hydrogen projects planned for 2030 are under construction or have taken Final Investment Decisions.[5] Alignment between supply and demand is needed to prevent a chicken-and-egg dilemma in which hydrogen producers won't invest in new capacity without demand certainty and consumers won't switch to hydrogen without secure supply. High energy prices and first-of-a-kind challenges have driven up project costs, meaning further policy support could also target de-risking investment and accelerating the commercialisation of low-carbon hydrogen production technologies.

[1] IEA (2024) World Energy Outlook. Table A.2c World Final Energy Consumption.

[2] Hydrogen can be stored at scale for long periods. From a technical standpoint this makes it well suited as a dispatchable fuel for power generation to meet peaks in electricity demand.

[3] CCUS-enabled hydrogen is not a zero-carbon technology pathway. It's not technically possible to capture all emissions using CCUS technology and there are also upstream leakages in the natural gas supply chain. Supply chain emissions are outside the scope of this analysis.

[4] Globally, current governments' targets for hydrogen production are four times global demand targets (2024 IEA Hydrogen review), Market analysts, Bloomberg New Energy Finance, make a similar assessment of the mismatch between demand and supply in their 2024 market report.

[5] IEA (2024) Hydrogen review.


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Helium
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Ammonia as an early route to market for electrolytic hydrogen

Green ammonia production, which uses electrolytic rather than fossil-fuelled hydrogen, is viewed by many market analysts and governments as an early route to market for electrolytic hydrogen at scale.[6]

This could in turn reduce production costs and unlock the use of electrolytic hydrogen in other sectors (see Figure 1, which outlines current and potential uses of hydrogen).

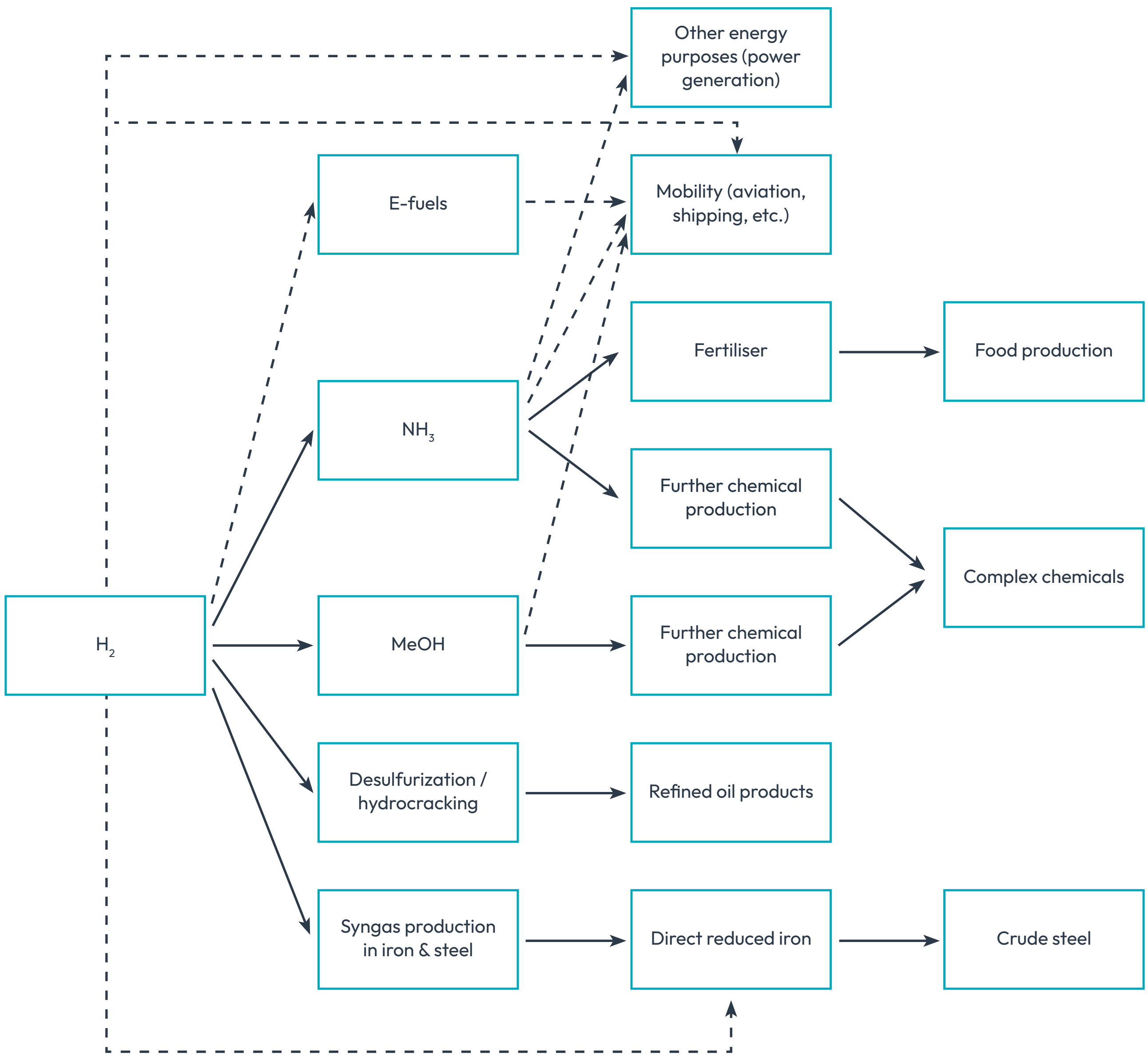


Figure 1: Hydrogen value chain overview. The solid lines represent current uses and the dashed lines future uses at scale.

[6] BNEF (2024) Scaling up hydrogen: the case for low-carbon ammonia.

Ammonia production currently accounts for around 2% of all global emissions.[6] Around 90% of these arise during the production of grey hydrogen (H_2), which is used as an input into the Haber-Bosch process to produce ammonia (NH_3). As electrolytic technologies are commercialised, this carbon-intensive hydrogen can be switched for low-carbon hydrogen and ammonia production can become far less emissions-intensive.[7]

Globally, around three quarters of all ammonia produced is used in nitrogen fertiliser production. The remainder is used to produce plastics, explosives and other industrial products. Several features of the ammonia value chain make it well suited to using large volumes of electrolytic hydrogen in the near term, including:

- **Demand and supply of electrolytic hydrogen and green ammonia grow in tandem.** There is no chicken and egg dilemma. Production and use of hydrogen for ammonia often happens in an integrated facility and most ammonia companies also make and/or trade fertiliser.
- **Ammonia is already traded at a moderate scale.** Existing infrastructure can be used to trade green ammonia at scale.[8]
- **Firms are already blending electrolytic hydrogen with grey hydrogen for ammonia production.** This indicates a high technology readiness that could be scaled.[9]
- **Building domestic capabilities in green ammonia production can improve both energy and food security.** However, further investment and potentially policy support may be needed to onshore the rest of the downstream fertiliser supply chain.
- **Longer term, green ammonia could be used at scale by a range of different end-use sectors.** Green ammonia is expected to play a large role as a decarbonised fuel in the global shipping industry.[10] Some countries also see a role for green ammonia in power generation and long duration energy storage.

Potential policies to stimulate green ammonia demand

There is a global project pipeline of 180 million metric tons of new low-carbon ammonia plants that could be built by 2035,[11] representing a 73% increase in current capacity. However, it's unclear how realistic this pipeline is, as securing offtake contracts and financing remains a challenge. Government support will play an important role in de-risking these early projects and creating the conditions for market growth. **In this policy brief, we model additional demand—and supply-side policies—to help close the gap in production costs between electrolytic hydrogen and fossil-fuelled hydrogen, which is key to unlocking demand for electrolytic hydrogen for use in ammonia and other sectors.**

7 The Royal Society, Ammonia: zero-carbon fertiliser, fuel and energy store

8 Around 10% of all global ammonia production is destined for the export market according to the IFA.

9 Ammonia Energy Association (2023) Technology status: ammonia production from electrolysis-based hydrogen

10 IEA (2023) Net Zero Roadmap: A Global Pathway to Keep the 1.5 °C Goal in Reach

11 Based on data from the IFA, the IEA, Argus, and FAOSTAT

Our modelling approach for this study

The Future Technology Transformations Hydrogen (FTT:H2) model that we use in this study simulates how different hydrogen production technologies would be deployed in response to different demand signals, from either specific sectors or geographies. The strength of the FTT models is their detailed, and realistic, representation of features of technology development and diffusion. This includes:

- The process of learning-by-doing, where technology costs fall in response to increasing deployment of a particular hydrogen technology
- Path-dependency – i.e. the ability of more widely used technologies to spread more rapidly
- The difference choices and preferences made by investors who are selecting between alternative hydrogen production technologies.

FTT:H2 covers 11 primary hydrogen production technologies. These include established methods like steam methane reforming (SMR) and coal gasification (with and without carbon capture and storage), as well as novel alternatives such as pyrolysis, alkaline electrolysis (ALK), proton exchange membrane electrolysis (PEM) and solid oxide electrolysis cell (SOEC). Each electrolytic technology requires electricity, which can either be purchased from the grid or generated on site using renewable energy, requiring additional upfront investments. Off-grid electrolysis capacity is aligned to the maximum generation load that the renewable power technologies can deliver. We assume no onsite electricity storage. All technologies are grouped in accordance to broad characterizations and shown as such in the results. SMR and coal gasification are combined and referred to as fossil-fuelled hydrogen (FF). The CCS variants together with pyrolysis are abated forms of hydrogen production (FF+CCS). All electrolytic technologies are grouped together under the ELEC classifier, while we sometimes make a distinction between electrolytic processes that purchase electricity from the grid (ELEC-Grid) and electrolytic processes with dedicated onsite renewable electricity generation (ELEC-VRE). A detailed overview of the technologies in FTT:H2—and the technology groupings—can be found in the Appendix (Table 5).

The FTT:H2 model considers hydrogen demand for feedstock purposes only, including for fertilisers, chemicals and refining. We establish a historical profile of demand for hydrogen and derivatives[12] and future demand for these is linked to projected growth rates in end-use sectors. For example, ammonia demand is dependent on the growth rate in the agriculture and chemicals sector. The demand profile used in this policy brief is shown in Figure 2; it is the same across all our policy scenarios. Other end uses, including in the energy system, are more speculative, particularly if there are alternative technologies that are also under consideration (e.g. direct electrification).

The FTT:H2 model can be used to analyse policy and market scenarios in different countries, end-use markets and hydrogen production technologies, and is calibrated on the best available data. See Appendix for more details.

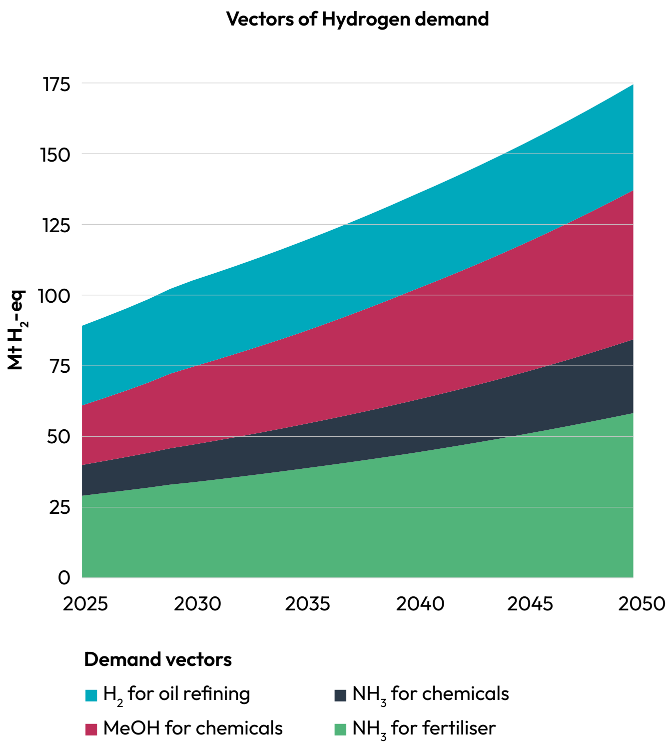


Figure 2: Global projections of hydrogen demand vectors

[12] While the model is detailed on the hydrogen production side, it lacks a granular resolution on trade. We apply a cost-supply curve approach that is adjusted for transportation costs from all potential origins of hydrogen supply to a weighted average demand region.

Scenario design

We model the following four policy scenarios:

1. **Reference scenario: current hydrogen policies (REF).** This scenario reflects the current state of technology deployment and readiness across all hydrogen technologies. The expected deployment of new hydrogen production facilities is based on the known pipeline of all projects globally that are at a good stage of maturity.[13] This scenario also reflects all current decarbonisation policies already implemented around the world but nothing further.
2. **Current hydrogen policies + carbon pricing (CP).** This scenario includes all the policies in the REF scenario as well as an additional global carbon tax that is applied to all hydrogen production technologies, starting at zero in 2025 and increasing linearly to \$200/tonne CO_2 by 2050.[14] Carbon taxes and emissions trading schemes raise the relative cost of hydrogen production technologies that release carbon vis-à-vis those that are zero carbon.
3. **Current hydrogen policies + mandates for green ammonia use in fertilisers (MD).** This scenario includes all the policies in the REF scenario as well as an additional global mandate for green ammonia. We assume the mandate starts at zero in 2025 and increases to 100% of all fertiliser production by 2050. Such a mandate would effectively create a new market in which only electrolytic hydrogen suppliers can operate by 2050. This could generate sufficient demand for electrolytic hydrogen to allow for cost reductions in production via economies of scale and learning-by-doing effects.[15] We only explore mandates for electrolytic hydrogen's use as ammonia in fertiliser because this is an established market that is also expected to grow, but cost reductions could unlock new use cases for electrolytic hydrogen in other sectors.
4. **Current hydrogen policies + carbon pricing on hydrogen production + mandates for green ammonia use in fertilisers (CP+MD).** This is the most stringent policy scenario, including all current policies as well as the global carbon tax and mandate on green ammonia use in fertilisers. Whereas the mandates seek to stimulate demand for electrolytic hydrogen, the carbon price seeks to level the playing field between high carbon and low-carbon hydrogen production technologies.

These stylised policy scenarios are intended to show the impact of additional strong policies on the global electrolytic hydrogen market. No assumptions are made on whether these policies align with a global emissions target by 2050 or specific national hydrogen production ambitions. Model runs that include these assumptions could be the focus of further research using FTT:H2, alongside other policy levers under consideration in different world regions, such as Carbon Border Adjustment Mechanisms (CBAM) or direct subsidies for hydrogen production and use.

We present our modelling results at the global level with a deep dive into Brazil, an important player in the global ammonia market. Our results are presented annually to 2050.

[13] We include all projects that have taken a Final Investment Decisions or are close to a Final Investment Decision listed in the IEA (2024) Hydrogen Production and Infrastructure Projects Database

[14] This carbon tax scenario is additional to all existing and announced ETS markets, which is represented in the FTT:H2 model through the prices of fossil fuels and electricity. The carbon tax rate is based on IEA's Net Zero Emissions scenario.

[15] Global mandates for green ammonia are not currently being considered as near-term demand-side policy option, though it has been advocated by Breakthrough Energy to stimulate the development of electrolytic hydrogen markets while limiting competitiveness impacts.

Results and insights

Global hydrogen insights

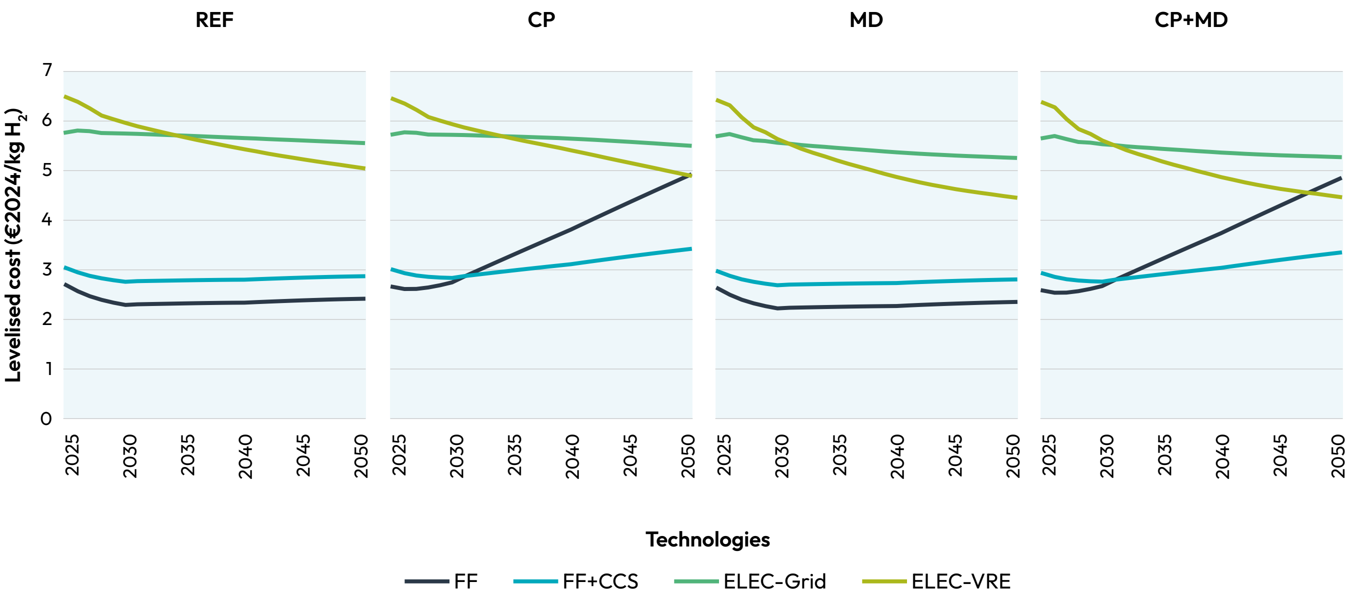


Figure 3: Global average levelised cost of hydrogen production by each technology group in each policy scenario. Global averages are unweighted and regional estimates vary a lot.

Figure 3 shows how the levelised costs of hydrogen[16] change over time for fossil-fuelled (FF), CCS-enabled (FF-CCS) and electrolytic hydrogen production across the four policy scenarios. We split the latter into grid-connected (ELEC-Grid) and dedicated renewables (ELEC-VRE) as they have different cost structures.

- **REF policy scenario:** With current policies, the global average levelised costs of electrolytic hydrogen production fall, but remain persistently higher than CCUS-enabled and fossil-fuelled hydrogen production. While production costs for ELEC-VRE decline considerably (by 1.4 €/kg between 2025 and 2050), this is not observed for ELEC-Grid (0.2 €/kg decline over the same period). This finding is driven by a different cost structure. ELEC-VRE has high CAPEX costs and benefits from learning-by-doing in both the electrolysis equipment and VRE technologies (see Table 1 in the Appendix). ELEC-Grid experiences the same cost decline for electrolysis equipment as ELEC-VRE, but electricity costs are determined by the structure of the local electricity market rather than any improvements in learning-by-doing effects.
- **CP policy scenario:** A global carbon levy increases the global average levelised cost of fossil-fuelled hydrogen by ~2.2 €/kg by 2050 and CCUS-enabled hydrogen to a lesser extent (~0.4 €/kg by 2050), because CCUS technology reduces the emissions intensity of hydrogen production. On average, this brings global average production costs of fossil-fuelled hydrogen close to the global average of ELEC-VRE by 2050. While this suggests cost parity, regional variation is considerable due to variation in gas prices (for FF and FF+CCS), electricity prices (for ELEC-Grid) and renewable energy potentials (for ELEC-VRE).
- **MD policy scenario:** A global mandate on green ammonia production helps to scale electrolytic hydrogen technologies and reduce the global average levelised cost of electrolytic hydrogen. It brings down costs of ELEC-VRE by an additional ~0.5 €/kg by 2050 on top of the cost decline found under the REF policy scenario (by ~1.4 €/kg between 2025 and 2050). However, no global cost parity is achieved in this scenario because there is no carbon price levied on fossil-fuelled hydrogen.

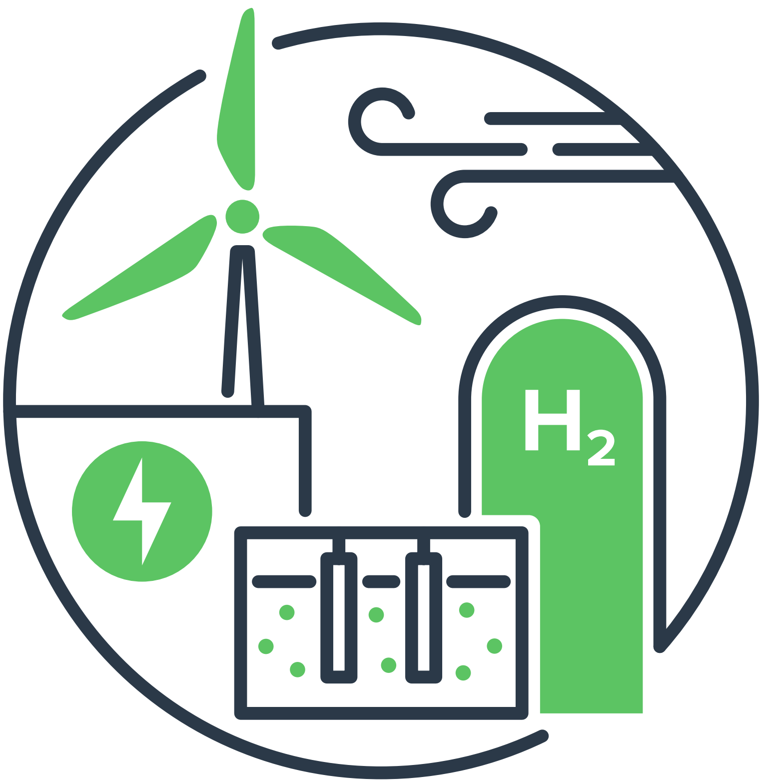
[16] Levelised costs represent the average costs over a project's lifetime, and it can be thought of as the break-even price at which hydrogen needs to be sold.

- **CP + MD policy scenario:** If a carbon tax is levied in addition to the mandate, the global average levelised costs of electrolytic hydrogen achieves cost parity around 2047.

The reductions in global average levelised costs shown in Figure 3 are driven, in part, by substantial learning-by-doing effects, which reduces the CAPEX and OPEX factors of hydrogen production equipment. Even though the levelised costs are, on average, higher for electrolytic hydrogen technologies across all policy scenarios, electrolytic hydrogen technologies also show the largest reduction in CAPEX costs (Table 1). Electrolytic technologies are less mature and so have a high learning rate as they commercialise, even under the REF scenario with current hydrogen policies.

		Policy scenario			
Category	Technology	REF	CP	MD	CP+MD
Fossil-fuelled (FF) hydrogen technologies	SMR	-4%	-6%	-3%	-4%
	Gasification	-5%	-2%	-4%	-3%
CCUS hydrogen technologies	SMR+CCS	-3%	-5%	-2%	-3%
	Gasification+CCS	-4%	-2%	-3%	-2%
Electrolytic hydrogen technologies	PEM	-12%	-18%	-45%	-45%
	ALK	-15%	-24%	-52%	-53%
	SOEC	-28%	-34%	-67%	-67%
Pyrolysis		-1%	-1%	-1%	-1%

Table 1: Overall learning-by-doing cost reduction on the upfront costs of equipment by technology between 2025 and 2050



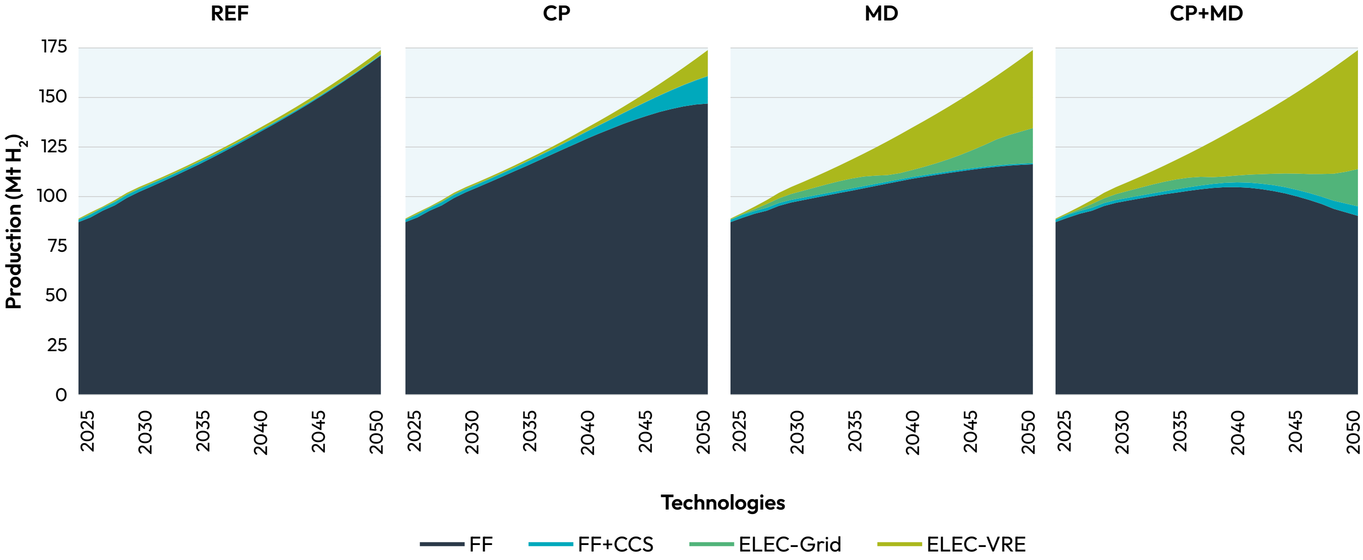


Figure 4: Global production volumes, by each technology group in each policy scenario

In Figure 4 we observe that global production of fossil-fuelled (FF) hydrogen remains higher than both CCUS-enabled (FF+CCUS) and electrolytic production pathways (ELEC-Grid and ELEC-VRE) across all scenarios. The mandates only target electrolytic hydrogen sales to produce green ammonia for use in fertilisers, which amounts to 53 Mt of hydrogen demand by 2050 – around 30% of the total. Our modelling shows that carbon pricing alone (CP), at the level we have tested, does not create sufficient demand for electrolytic hydrogen. The mandates alone (MD) achieve a sizeable deployment of electrolytic hydrogen but, due to the lack of competitiveness with fossil-fuelled hydrogen, will not lead to a spill-over of electrolytic supply to other hydrogen demand segments, aside from fertilizers, unless supported by other policies in those sectors.

A combination of carbon prices and mandates (CP+MD) does lead to some spill-over of demand for electrolytic hydrogen, even without additional policies in those sectors. By 2050, 45% of all hydrogen demand is supplied by electrolytic processes and an additional 3% through CCS-enabled processes. In the carbon price scenario, CCS-enabled hydrogen technologies are cost competitive with fossil-fuelled hydrogen options in many regions. However, the expansion of CCS-enabled hydrogen production capacity is not sufficient to divert away from fossil-fuelled hydrogen production, in part because there is relatively limited deployment of CCUS-enabled hydrogen, which makes it challenging for the technology to scale. Fossil-fuelled hydrogen, by comparison, is well established with technology lock-in. Mandates can break this lock-in effect by scaling demand for electrolytic hydrogen. When combined, mandates and carbon pricing (CP+MD) do lead to more displacement of fossil-fuelled hydrogen for electrolytic hydrogen.

While Figure 3 and Figure 4 show the global average impacts of these policies, there is significant variation in the levelised costs of hydrogen across different countries and production technologies, particularly for electrolytic hydrogen. Figure 5 displays the production costs of specific electrolytic hydrogen production technologies for the CP+MD policy scenario.

The regional variation in grid-connected electrolytic hydrogen costs is due to differences in regional electricity prices. Production costs range between 1.8 and 11.2 €/kg across the three grid-connected electrolytic technology options in 2025. By 2050, the range is between 1.5 and 17.1 €/kg. On average, production costs remain at around 6 €/kg and 5.8 €/kg for PEM-grid and ALK-grid respectively, while SOEC-grid remains around 5 €/kg between 2025 and 2050.

Electrolytic production with dedicated onsite renewable electricity generation shows a greater decline in production costs than grid-based electrolytic production. Although both electrolytic routes experience cost reductions from learning-by-doing effects for electrolyser technologies, only dedicated renewables will also experience reductions in the cost of electricity. This is because the price of grid-based electricity is set in a regional market by the mix of generation technologies. Our modelling shows large regional variation in the cost of electrolytic production pathways with dedicated renewables, with initial cost ranges between 2.7 and 15 €/kg for PEM-VRE and ALK-VRE. This range declines to 1.7 to 11 €/kg by 2050. The range for SOEC-VRE is considerably smaller, with estimates between 3 and 6.9 €/kg initially, declining to a range of 1.9 to 5.3 €/kg by 2050.[17]

[17] These production cost ranges align well with estimates provided by the IEA in their latest Global Hydrogen Review report. They found 2023 production cost ranges between 4 and 12 €/kg for electrolytic hydrogen production with dedicated renewable electricity.

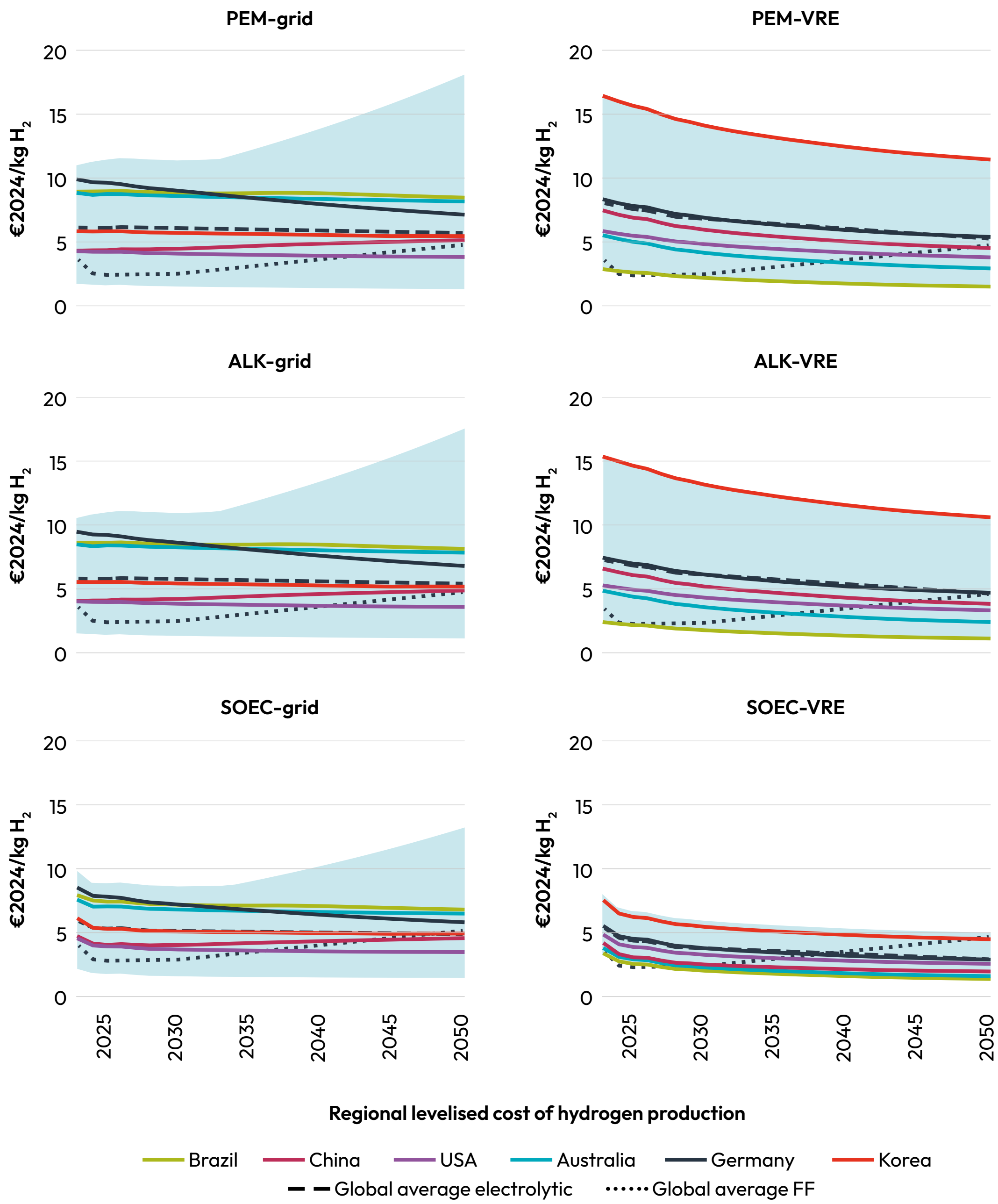


Figure 5: Levelised cost of electrolytic hydrogen production under the CP+MD scenario by selected model region[18]

Figure 5 shows that, in the CP+MD scenario, electrolytic hydrogen can be cost competitive with fossil fuel-based hydrogen in certain countries. Electrolytic hydrogen production with dedicated onsite renewable electricity generation in Brazil reaches cost parity with the global average fossil-fuelled hydrogen production between 2027 and 2030. Renewable electricity generation costs in the United States and Australia are such that electrolytic hydrogen production costs are lower than the global average, while China and Germany are similar to the global average. Meanwhile, off-grid electrolytic hydrogen production in South Korea will likely not be able to compete with electrolytic hydrogen production elsewhere, as VRE deployment in South Korea tends to be relatively more expensive.

Grid-connected electrolytic hydrogen production can sometimes outcompete electrolytic hydrogen production with dedicated renewables within a country. However, this depends heavily on the relative costs of electricity prices in a regional market versus potential renewable energy capacity, which drives the cost of dedicated renewables for electrolytic hydrogen production. Investment in dedicated renewable energy is most profitable in regions where VRE sources can operate at higher capacity factors. For example, Brazil is renowned for reliable wind resources, which is reflected in lower production costs of electrolytic hydrogen with dedicated VRE electricity generation.

[18] The left column shows grid-connected electrolysis, while the right column shows electrolysis with dedicated onsite variable renewable energy (VRE) capacity. PEM: Proton electron membrane; ALK: Alkaline electrolysis; SOEC: Solid oxide electrolysis cell.

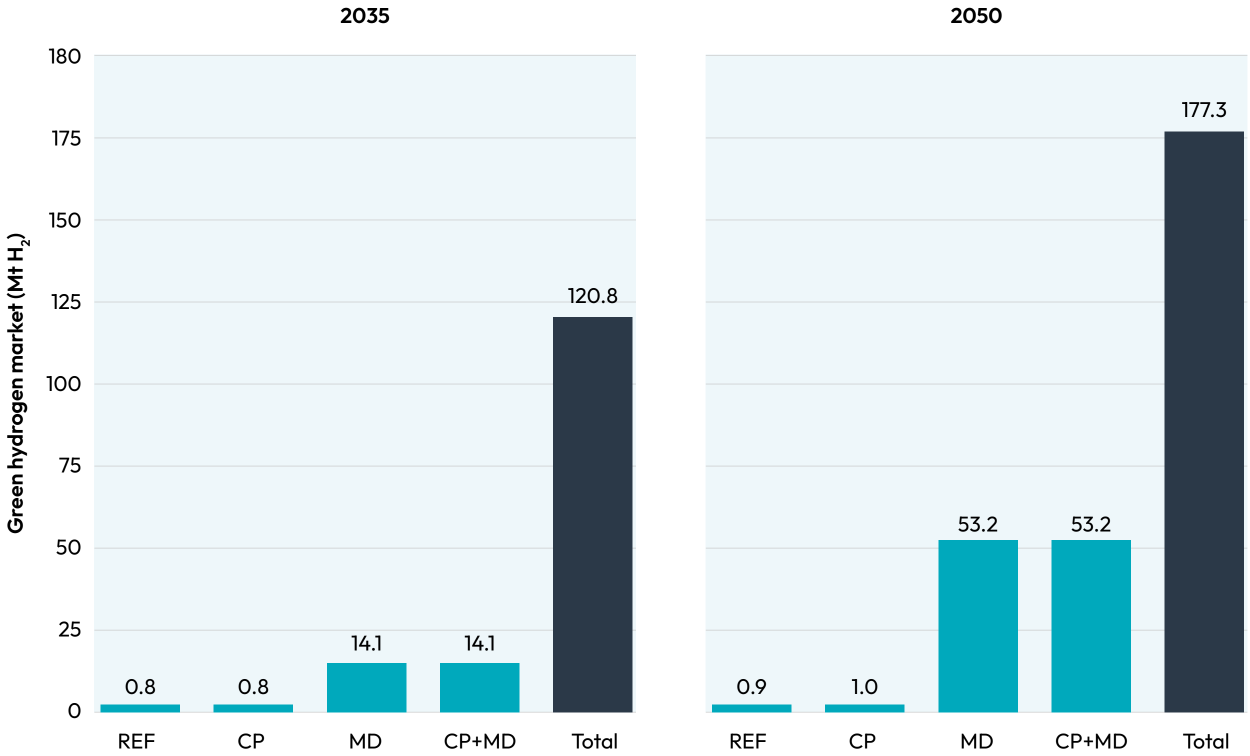


Figure 6: Global electrolytic hydrogen demand (shown in blue) in the various scenarios relative to total hydrogen demand (shown in black)

Figure 6 shows it is unlikely that carbon pricing alone will be sufficient to stimulate large-scale demand for electrolytic hydrogen for use in ammonia and nitrogen-based fertilisers – a further demand mandate is required. There is little overlap in countries with high nitrogen-based fertiliser consumption and competitive electrolytic hydrogen production costs—Brazil (6% of global fertilizer consumption in 2022) being one of the few exceptions. Fertiliser demand is high in China (22% of global consumption in 2022), India (19%) and the US,[19] but our modelling shows they are comparatively higher-cost locations for electrolytic hydrogen production.

By 2050, we find that around 2% of the hydrogen demand for fertiliser production is electrolytic in the CP scenario. Enacting a green fertiliser mandate forces fertiliser producers to purchase around 53 Mt of electrolytic hydrogen by 2050, representing around 30% of total hydrogen production globally. Electrolytic hydrogen production is greatest in the CP+MD scenario, where it reaches 74 Mt (Figure 4). In countries where electrolytic hydrogen production is competitive, it will be able to compete with fossil-fuelled hydrogen in demand segments beyond ammonia-based fertilizers.

As shown in Table 2, producing 74 Mt of electrolytic hydrogen will require significant investments in new renewable electricity capacity, amounting to €1.9 trillion between 2025 and 2050. Around 76% of the total investment required in the CP+MD scenario is to scale up renewable electricity generation to power electrolysers.

As lower-carbon hydrogen technologies are rolled out, the overall emissions intensity of hydrogen production is lowered. Our modelling shows that global emissions due to hydrogen production are nearly halved by 2050 in the CP+MD scenario.

[19] FAOSTAT, Fertilisers by Nutrient dataset.

		REF	CP	MD	CP+MD
Cumulative investment between 2025 and 2050 (billion € 2024)	Unabated fossil-fuelled (FF) hydrogen capacity	225	248	153	167
	Abated fossil-fuelled (FF+CCS) hydrogen capacity	5	42	5	16
	Grid-connected electrolytic (ELEC-Grid) capacity	3	3	41	36
	Off-grid electrolytic (ELEC-VRE) capacity	14	30	221	235
	Dedicated VRE capacity for off-grid electrolytic production	45	105	1188	1,287
	Total	292	428	1,608	1741
Annual energy consumption in 2050 (Mtoe/y)	Unabated fossil-fuelled (FF) technologies	913	740	627	462
	Abated fossil-fuelled (FF+CCS) technologies	2	71	3	25
	Grid-connected electrolytic (ELEC-Grid) technologies	1	1	83	89
	Off-grid electrolytic (ELEC-VRE) technologies	<1	2	15	15
Dedicated VRE electricity generation in 2050 (Mtoe/y)		10	60	171	270
Annual emissions in 2050 (Gt CO_2)		2.1	1.5	1.5	1.0
Cumulative emissions between 2025 and 2050 (Gt CO_2)		38	34	33	29

Table 2: Overview of global investments, energy consumption and emissions in the four policy scenarios

Focus on Brazil

Policy context

Brazil, the largest fertiliser market in Latin America, produces about 1.5 million tonnes of ammonia (0.27 million tonnes of hydrogen-equivalents) per year across four manufacturing locations, accounting for about 1% of global production. However, demand outstrips supply and the country imports 87% of its nitrogen-based fertilisers, whose costs are heavily influenced by natural gas prices, the main energy input into ammonia production.

With fertiliser demand expected to increase in the coming decades, the Brazilian government wants to reduce imports to 45% of overall fertilizer demand by 2050.[20] Looking to capitalise on reliable wind and solar resources to create a competitive advantage for electrolytic hydrogen production, it has introduced tax credits for low-carbon hydrogen production facilities as well as a National Fertiliser Plan, which could be an important complementary policy to increase demand for domestic low-carbon ammonia for use in fertilisers.

With its grid already 90% powered by renewables, Brazil has been identified as a potential exporter of both hydrogen and electricity. Supply-side policies to reduce the cost of developing electrolytic hydrogen production include the Low-Carbon Hydrogen Development Program, established in 2024 to provide tax credits for eligible projects alongside the Regime for Low-Carbon Hydrogen Production, which provides tax and tariff exemption for production equipment and materials. The Brazilian Development Bank, BNDES, is also operating several climate financing initiatives providing low-interest rates to electrolytic hydrogen projects. With these incentives in place, several large-scale green ammonia projects are being developed near ports.

Modelling results for Brazil

Our modelling shows that Brazil is one of the lowest-cost regions for electrolytic hydrogen production across all four policy scenarios.[21] Across all electrolytic hydrogen production technologies with dedicated onsite VRE capacity, the price in Brazil ranges from 2-2.3 €/kg in the REF scenario to 1.7-1.9 €/kg in the CP+MD scenario by 2050, which combines a global green ammonia mandate and a global carbon price. Fossil-fuelled hydrogen production reaches 2.3 €/kg by 2050 in the REF scenario and 4.7 €/kg in the CP+MD scenario.

Consequently, electrolytic hydrogen with dedicated onsite renewable electricity generation makes up a significant portion of Brazil's overall hydrogen production mix in the REF scenario without needing any further policy support (79%) – far more than what is observed at the global level (1.3%) by 2050 (Figure 7). In the CP+MD scenario, deployment of electrolytic hydrogen with dedicated onsite renewables increases significantly in both in relative and absolute levels (see Table 3).

[20] Plano Nacional de Fertilizantes with MAPA, Embrapa e INPI data

[21] This aligns with modelling studies by BNEF - 2023 Hydrogen Levelized Cost Update: Green Beats Gray

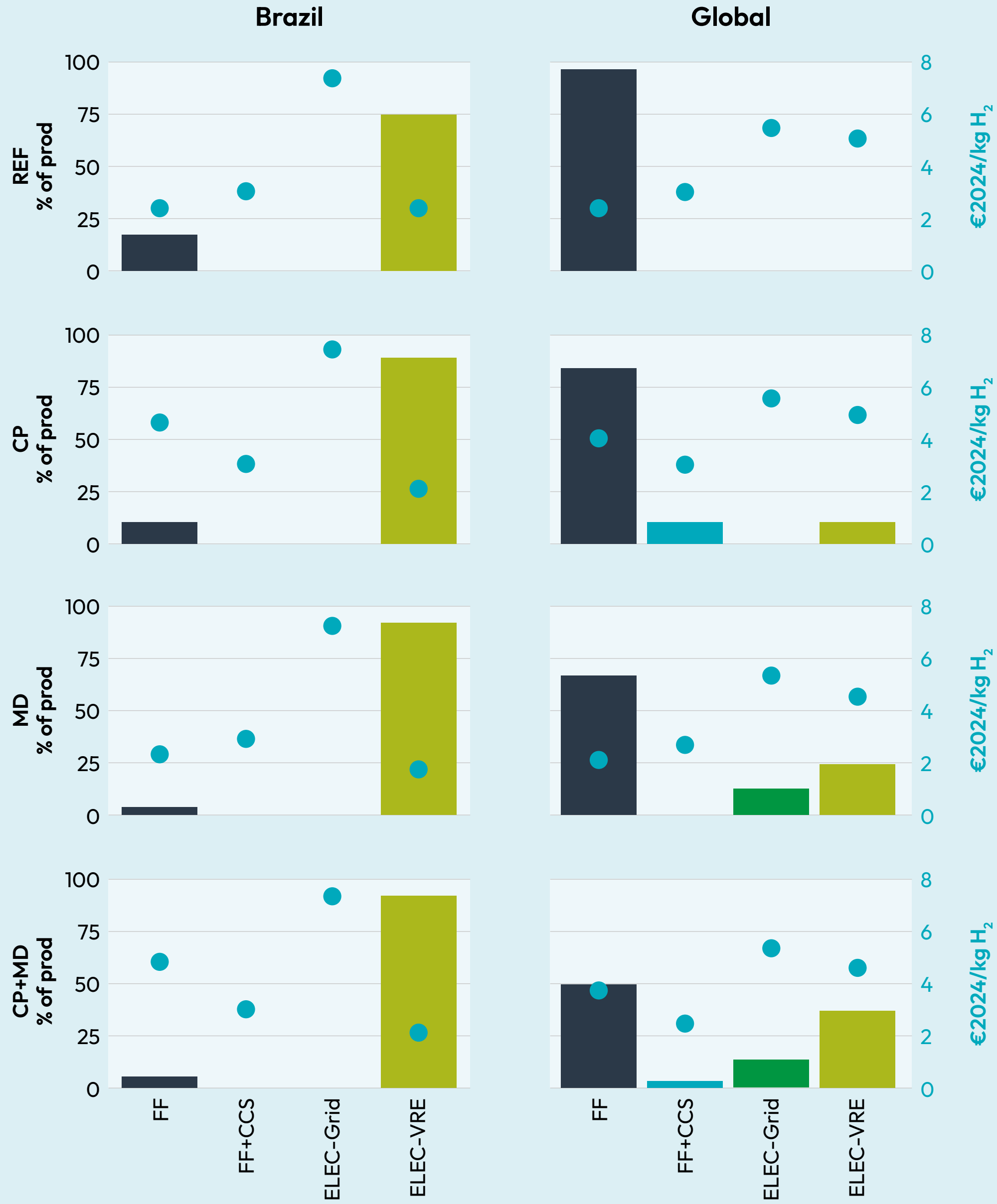


Figure 7: Comparison of hydrogen production in Brazil versus the world in each scenario for 2050.
The blue dots indicate the average levelised cost of the technologies.

Brazil's current import dependency on (high-carbon) ammonia for use in fertilisers is in part because it is relatively costly to produce fossil-fuelled hydrogen domestically relative to other regions with large production facilities. This situation will likely persist if no further policies are implemented.

Domestically, electrolytic hydrogen is competitive with fossil-fuelled hydrogen and a global carbon price on hydrogen production would strengthen this. However, a mandate would be required to increase demand for electrolytic hydrogen globally, otherwise the offtake of Brazilian hydrogen-based products remains low (see Table 3).

When a global mandate is introduced to use electrolytic hydrogen in fertiliser production, Brazil's hydrogen sector expands significantly. Total production volumes by 2050, which is predominantly electrolytic hydrogen, increases about eight-fold compared to the REF scenario. This completely overturns the current trade balance in hydrogen-derived products (see Table 3). While a global mandate may sound implausible, the market for nitrogen-based fertilisers is highly concentrated, which reduces the coordination required to shift market demand – the 10 largest country producers account for three quarters of global production, while the 10 largest importers account for around 65% of global trade.[22]

[22] FAOSTAT, Fertilisers by Nutrient dataset,

Mt H_2	Production	Demand	Apparent net exports
REF	1.7	4.2	-2.6
CP	2.8	4.2	-1.4
MD	14.4	4.2	10.2
CP+MD	14	4.2	9.8

Table 3: Hydrogen production, demand and apparent net exports (production minus demand) in Brazil by 2050

While our modelling shows where electrolytic hydrogen production capacity could increase, it does not fully account for potential bottlenecks associated with large scale project development and deployment. These bottlenecks can be financial (e.g. cost of capital) or related to the energy system (e.g. grid connections, scale-up of VRE deployment). In the mandate scenarios (MD, and CP+MD) we find that Brazil would have to invest between €246 and €272 billion over the next 25 years to produce between 13.2 and 13.7 Mt of off-grid electrolytic hydrogen by 2050 (see Table 4). Around 81% of all investments would be for expanding onshore wind capacity, which in turn would enable greater deployment of green hydrogen production capacity and output. This is excluding any investments in additional power generation capacity connected to the grid to supply grid-connected electrolytic hydrogen capacity. To put the green hydrogen production in the mandate scenarios into perspective, the amount of electricity the dedicated onsite wind turbines will need to produce by 2050 is about the same as Brazil's total electricity demand in 2023,[23] which makes this level of scale-up extremely ambitious. Over the 2025-2050 period, cumulative emissions from hydrogen production decline across all scenarios relative to the REF scenario.

		REF	CP	MD	CP+MD
Cumulative investment between 2025 and 2050 (billion € 2024)	Unabated fossil-fuelled (FF) hydrogen capacity	1.1	1.1	1.0	1.2
	Abated fossil-fuelled (FF+CCS) hydrogen capacity	0.1	0.1	0.1	0.1
	Grid-connected electrolytic (ELEC-Grid) capacity	0.1	0.1	0.2	0.2
	Off-grid electrolytic (ELEC-VRE) capacity	4.8	6.5	50.2	45.4
	Dedicated VRE capacity for off-grid electrolytic production	13.0	18.4	220.8	198.7
	Total	19.0	26.2	272.2	245.6
Annual energy consumption in 2050 (Mtoe/y)	Unabated fossil-fuelled (FF) technologies	1.7	1.2	3.2	3.9
	Abated fossil-fuelled (FF+CCS) technologies	<0.01	<0.01	<0.01	0.1
	Grid-connected electrolytic (ELEC-Grid) technologies	<0.01	<0.01	<0.01	<0.01
	Off-grid electrolytic (ELEC-VRE) technologies	<0.01	<0.01	0.4	0.1
Dedicated VRE electricity generation in 2050 (Mtoe/y)		6.1	12.1	63.6	61.5
Cumulative emissions between 2025 and 2050 (Gt CO_2)		199	188	191	186

Table 4: Overview of investments, energy consumption and emissions in the various scenarios in Brazil

[23] IEA, Brazil – electricity generation sources

Conclusions

- Current hydrogen policies are insufficient to kickstart the large-scale deployment of green hydrogen production.
- Our modelling shows that a carbon price can bring the production costs of fossil-fuelled hydrogen up to that of electrolytic hydrogen, although there are large differences across regions. In some, a lower carbon price would suffice to achieve cost parity, while others require a much higher carbon price to achieve this outcome. Combining a mandate with carbon prices brings forward the timing of when the two reach cost parity. Our scenarios do not make any assumptions about future global emissions levels or about the use of electrolytic hydrogen as an energy vector.
- Only regions with high renewable potential are cost competitive on electrolytic hydrogen. In the case of Brazil, green hydrogen can get close to cost parity to fossil-fuelled hydrogen in the REF scenario.
- Our policy scenarios show that it is technically possible for Brazil to become self-sufficient in nitrogen-based fertilisers, reducing import dependency and even becoming a regional exporter of electrolytic hydrogen. Mandates on using green ammonia for fertilisers will be a critical policy driver and could be reinforced by carbon pricing on hydrogen production. However, our modelling does not fully reflect other policy consideration or potential in-country challenges to deploying electrolytic hydrogen production, including the significant expansion of new renewables generation.
- There is high potential for cost reductions of electrolytic hydrogen equipment, lowering the production costs of electrolytic hydrogen. Furthermore, renewable electricity generation technologies will also likely experience a reduction in costs over time, which further helps lowering the costs of electrolytic hydrogen production with dedicated onsite renewable electricity generation. By comparison, grid-based electrolysis experiences cost reductions for electrolyser technologies but less so for electricity, which is determined by the local market structure. Electricity costs will be determined by the structure of regional electricity prices, which is not limited to CAPEX cost of renewables. However, in this study we have not broadened the scope to the wider energy system.

Recommendations

Policymakers can consider a range of different policy levers to kickstart the commercialisation of electrolytic hydrogen production. In this brief, we applied a global carbon price on hydrogen production technologies and a mandate to promote demand for electrolytic hydrogen as this is an often-overlooked aspect in hydrogen strategies.[24] Our modelling shows that a combination of two such policies can lead to significant uptake of low-carbon electrolytic hydrogen. Further model runs could focus on alternative policy scenarios, exploring, for example, the impact of introducing a higher carbon price sooner than 2050 and of different types of demand- and supply-side subsidies. Comparing these alternative policy scenarios would provide policymakers with a deeper understanding of the relative strengths and limitations of each policy option. We can also expect the insights and modelling to change if the policy objectives are expanded beyond kickstarting electrolytic hydrogen production and use. For example, in an earlier EEIST policy brief which used a different modelling approach, grid-based electrolysis in India provided better energy system security, resilience and affordability than dedicated renewables.

Our analysis also shows that electrolytic hydrogen with dedicated onsite renewable electricity generation is mostly limited to regions with vast and reliable renewable resources. Policy should target regions with cheap renewable energy resources. Brazil is a prime example given its wind potential and there may be opportunities to exploit. However, green hydrogen deployment also carries a risk: if demand does not materialise in line with expectations when investment decisions are made, this capacity may become stranded. Greater focus could be given to demand-side policies, including the potential role for mandates in specific end-use sectors.

[24] Odenweller, A., Ueckerdt, F. (2025) **The green hydrogen ambition and implementation gap**.

Technical Appendix: FTT Hydrogen model

Technology diffusion

Figure 8 displays the flow of information in FTT:H2. Building on techno-economic cost components (see Table 6) we estimate levelised cost of hydrogen production for each technology and region. Technologies are compared on a pair-wise basis to determine preferences. Preferences, together with substitution frequencies, feed into the decision-making core of the model to determine technology substitution. The preferences are based on the levelised cost of hydrogen and account for variability around cost components.

Based on the tranche of new capacities, we can feed back the learning-by-doing effects to the techno-economic cost data, which influences the next round of decisions. Domestic content of hydrogen capacity together with hydrogen (or derivative products) for the export market, determine utilisation of capacity. Overall utilisation across all technologies determines capacity growth; if the system is operating close to full utilisation, then capacity is expanded. The overall capacity factor is reflective of the competitiveness of hydrogen production in each region.

Based on the utilization of technologies, the model estimates how much energy is consumed, CO_2 emissions released, the level of investments required, and hydrogen prices. Hydrogen prices have a large impact on the production costs of ammonia, accounting for between 40% and 60% of the current input costs. In turn, ammonia is the largest cost component of nitrogen-based fertilisers and it is likely that fertiliser demand will continue to grow in the future.

Technology classification

Table 5 provides an overview of the technology options included in FTT:H2. It includes incumbent technologies, such as steam methane reforming, gasification and alkaline electrolysis. Novel technologies are also included, such as CCS applications, pyrolysis, proton-exchange membrane electrolysis and solid oxide electrolysis cells. The hydrogen production technologies are often matched with a colour. When electrolytic hydrogen is produced using electricity from the grid it is often referred to as 'yellow' hydrogen, whereas it is 'green' if the electricity is solely sourced from renewables, often implying onsite generation. Biomass gasification (with and without CCS) and naturally found hydrogen (sometimes referred to as 'white' hydrogen) are not included in this analysis. Renewable biomass potentials are limited and cost factors are poorly understood.[25] The potential of white hydrogen is equally uncertain.

[25] Hanssen, S.V., Daioglou, V., Steinmann, Z.J.N. et al. (2020) The climate change mitigation potential of bioenergy with carbon capture and storage.

Full name	Abbreviation	"Colour"	Grouping 1	Grouping 2	Description
Steam methane reforming	SMR	Grey	FF		SMR is currently the most widespread hydrogen production technology. It requires natural gas as a feedstock input.
Coal gasification	Coal	Grey/ black			Coal gasification is a mature technology that has been around since the early 1900s. Currently, China is the only region with widespread use.
Steam methane reforming with carbon capture and storage	SMR+CCS	Blue	FF+CCS[26]		The CCS variants of SMR and coal gasification are novel. There are various plants in the pipeline that will include CCS, which will increase costs and reduce greenhouse gas emissions during hydrogen production.
Coal gasification with carbon capture and storage	Coal+CCS	Blue			
Pyrolysis	PYR	Turquoise			Pyrolysis is a process that requires fossil fuel as a feedstock input (typically natural gas). The feedstock is broken down into solid carbon and hydrogen in the absence of oxygen. Therefore, there are virtually no CO_2 emissions.
Proton-exchange membrane connected to the power grid	PEM-Grid	Yellow	ELEC-Grid	ELEC	PEM, ALK and SOEC are various forms of electrolytic hydrogen production. They differ in set-up, efficiency and equipment cost, but the main principle is that water is split into oxygen and hydrogen via an electrochemical process. SOEC typically also requires energy for process heating. The grid-connected variant purchases its electricity from the grid.
Alkaline electrolysis connected to the power grid	ALK-Grid	Yellow			
Solid oxide electrolysis cell connected to the power grid	SOEC-Grid	Yellow			
Proton-exchange membrane connected to dedicated onsite renewable electricity generation	PEM-VRE	Green	ELEC-VRE		PEM, ALK and SOEC are various forms of electrolytic hydrogen production. They differ in set-up, efficiency and equipment cost, but the main principle is that water is split into oxygen and hydrogen via an electrochemical process. SOEC typically also requires energy for process heating. With dedicated onsite renewable electricity generation, purchase of electricity is avoided, but this is replaced by much higher upfront investment costs and typically lower capacity factors.
Alkaline electrolysis connected to dedicated onsite renewable electricity generation	ALK-VRE	Green			
Solid oxide electrolysis cell connected to dedicated onsite renewable electricity generation	SOEC-VRE	Green			

Table 5: Technology scope included in FTT:H2

[26] While the pyrolysis process does not require carbon capture equipment, it does require fossil fuel inputs (typically natural gas), but it does not produce onsite emissions as the end produce is solid carbon and hydrogen. This excludes emissions occurring upstream. Due to these characteristics, the pyrolysis process has been grouped together with FF+CCS.

Technology cost components

Table 6 displays the techno-economic cost components as used in FTT:H2. This table is constructed by combining information from several sources.[27] Regional diversification of cost components is limited to three geographies – Europe, the US and China – and only to CAPEX factors. All other regions are proxied to one of the three. The largest source of regional diversification is due to energy costs, comprising of electricity, natural gas and coal depending on the hydrogen production route. We use energy price projections from E3ME, which are based on the World Bank Commodity Markets Outlook for the short term and ENERDATA for the long term, and apply those to the feedstock and energy input needs.

The electrolytic processes with onsite VRE generation do not include an electricity demand factor. Instead, additional CAPEX and OPEX factors related to VRE generation are added as a cost component. The model also limits the maximum capacity factor at which such processes can operate.

Indicator	CAPEX	Fixed OPEX	Variable OPEX	Feedstock input	Process heat demand	Electricity demand, mean	Emission factor	Learning rate	Discount rate	Lifetime	Build time
Unit	€/kg H_2 cap	€/kg H_2 cap	€/kg H_2 prod	€/kg H_2 prod	€/kg H_2 prod	€/kg H_2 prod	kg CO_2 / kg H_2				
1 SMR	1.6	0.1	0.00	44.5	8.9	3.7	9.50	-0.11	0.10	30	2
2 SMR+CCS	2.3	0.1	0.01	44.5	13.3	4.1	2.85	-0.12	0.10	30	2
3 Gasification	3.1	0.1	0.29	58.0	8.9	3.7	19.00	-0.11	0.10	30	2
4 Gasification+CCS	7.1	0.2	0.44	58.0	13.3	4.1	5.70	-0.12	0.10	30	2
5 Pyrolysis	2.5	0.1	0.30	44.5	1.0	3.7	1.20	-0.11	0.10	30	2
6 PEM-grid	3.7	0.1	0.19	0.0	0.0	55.5	0.00	-0.18	0.10	25	2
7 ALK-grid	2.5	0.1	0.18	0.0	0.0	54.3	0.00	-0.21	0.10	25	2
8 SOEC-grid	5.2	0.1	0.50	0.0	14.0	39.0	1.00	-0.25	0.10	20	2
9 PEM-VRE	3.7	0.1	0.19	0.0	0.0	0.0	0.00	-0.18	0.10	25	2
10 ALK-VRE	2.5	0.1	0.18	0.0	0.0	0.0	0.00	-0.21	0.10	25	2
11 SOEC-VRE	5.2	0.1	0.50	0.0	14.0	0.0	1.00	-0.25	0.10	20	2

Table 6: Techno-economic cost components used in FTT:H2. All monetary units have been deflated to 2010 base year.

[27] Based on data from PRIMES, IEA, BNEF, and IRENA.

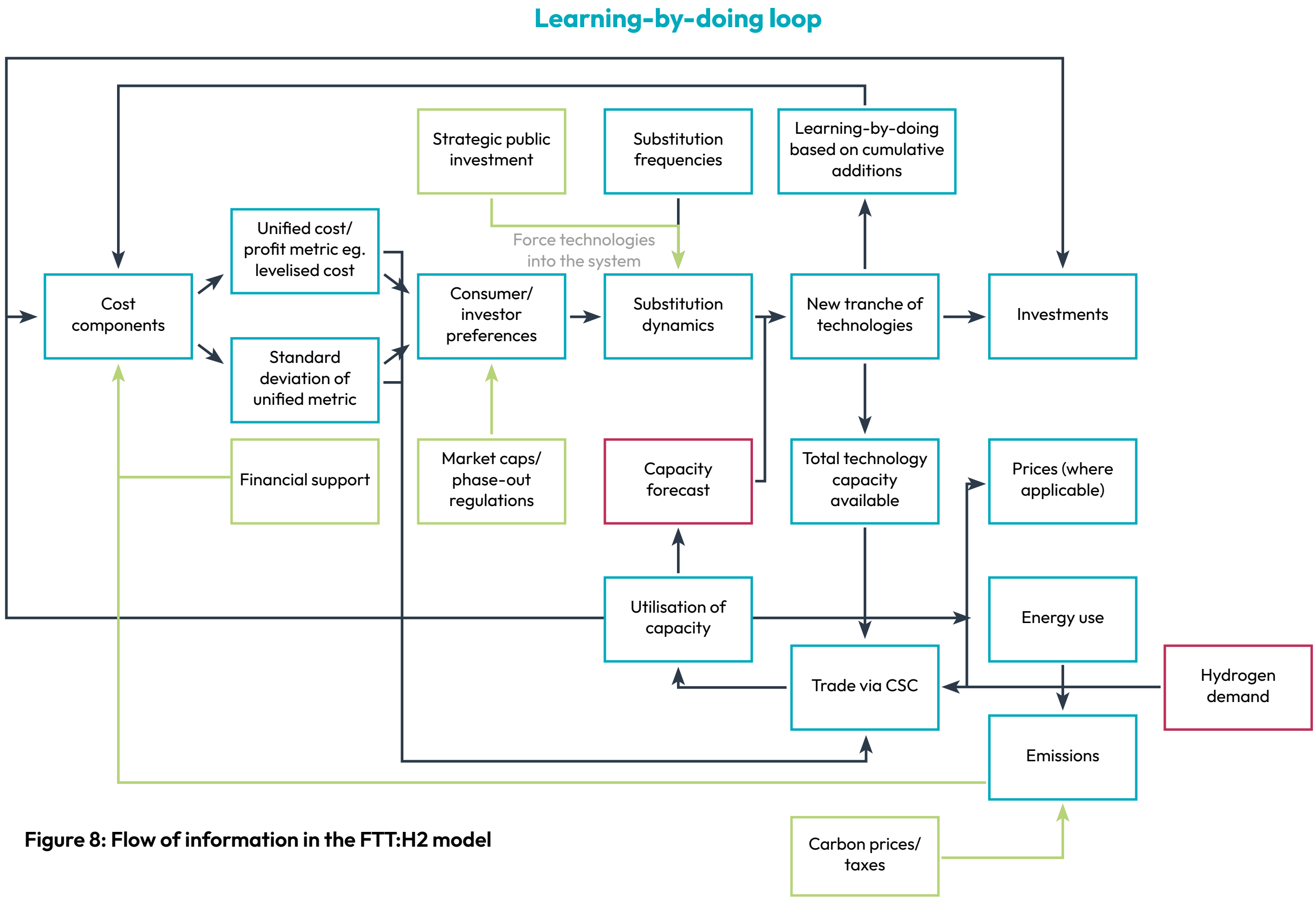


Figure 8: Flow of information in the FTT:H2 model

Fertiliser module

In addition to FTT:H2, we use a fertiliser module to estimate the endogenous demand for green fertiliser. The main driver is production cost differentials between grey and green fertiliser. The bulk of costs (40-60%) are from the hydrogen inputs to produce ammonia. We apply a Bass diffusion model to estimate the composition of green versus grey fertiliser demand.[28]

Demand for green fertiliser must be linked to its production, which, in turn, depends on the production of electrolytic hydrogen. This is why we include market splits in this model. In the electrolytic market, only electrolytic capacity can bid, while in the default market, all capacity can bid. The size of the green market can be dictated by policy mandates or the fertiliser module for the relevant demand vector.

Data limitations

Despite using best available data, many of the model's inputs are subject to uncertainties, and its outputs are best interpreted in comparative terms ('policy A is likely to outperform policy B on criterion X') rather than treated as precise predictions. All models have their limitations. In the case of FTT hydrogen there is a very stylised representation of trade in hydrogen, or derivatives.

Representation of hydrogen trade

Hydrogen and its derivatives can be traded in various forms (such as liquid organic hydrogen carriers, ammonia, pipelines or cryogenic hydrogen), each with different transportation costs depending on the distance between trade partners. We simplify these costs by assuming that the main mode of transport will be via ammonia. Ammonia trade already occurs at scale and 85% of the announced hydrogen projects involve trade in the form of ammonia.

We make further assumptions on the domestic content of hydrogen production based on domestic demand. In regions with a historical import dependency (for example, the EU), we assume a 60% domestic content, while in other regions we assume an 85% domestic content. This means that we force e.g. 60% of the domestic demand to be sourced domestically, unless there is insufficient capacity available. The remaining unmet demand is combined in a global demand pool. Using the remainder of unused capacity in the global system and their levelised cost estimates, we construct a cost-supply curve, which is adjusted for transportation costs. We estimate the weighted average transportation cost for each exporting region based on the average distance from the exporter to all importers. Hydrogen demand volumes serve as weights.

A major limitation of this approach is that we lose information on bilateral trade flows. Instead, we can only evaluate net trade by comparing demand and production levels. Equally, this approach does not allow us to evaluate policy impacts due to a carbon-border adjustment mechanism, for example. It is also likely that countries will close bilateral trade agreements which would have to be honoured regardless of economic performance.

[28] Bass diffusion models determine the number of adopters of a new product or service and includes the innovator and imitator effects.

Assumptions used in the scenario design

Dedicated onsite renewable electricity generation

For the electrolytic pathways that include onsite electricity generation, we included assumptions on what the composition of the renewable electricity capacity is in each region. This is based on the available renewable resources and cost performance. The renewable electricity technologies considered are onshore wind power, offshore wind power and solar PV. Table 7 shows the composition of renewable electricity capacity assumed in each region.

CAPEX, OPEX and capacity factors for each renewable technology are taken from FTT:Power in a baseline scenario.[29] This baseline scenario is in line with the reference scenario used in this policy brief. These factors include learning-by-doing effects and changes to capacity factors based on curtailment and renewable resource depletion.

Table 7: Composition of renewable electricity generation by technology used for the ELEC-VRE technology group

Region	Onshore wind power	Offshore wind power	Solar PV
BE	80%	20%	0%
DK	50%	50%	0%
DE	80%	20%	0%
EL	80%	10%	10%
ES	70%	10%	20%
FR	70%	10%	20%
IE	50%	50%	0%
IT	70%	10%	20%
LX	100%	0%	0%
NL	20%	80%	0%
AT	100%	0%	0%
PT	50%	20%	30%
FI	100%	0%	0%
SW	100%	0%	0%
UK	20%	80%	0%
CZ	100%	0%	0%
EN	90%	10%	0%
CY	50%	10%	40%
LV	100%	0%	0%
LT	100%	0%	0%
HU	100%	0%	0%
MT	20%	20%	60%
PL	90%	10%	0%
SI	100%	0%	0%
SK	100%	0%	0%
BG	70%	10%	20%
RO	70%	10%	20%
NO	100%	0%	0%
CH	100%	0%	0%

[29] Nijsse, F.J.M.M., Mercure, JF., Ameli, N. et al (2023) The momentum of the solar energy transition

Region	Onshore wind power	Offshore wind power	Solar PV
IS	50%	50%	0%
HR	70%	10%	20%
TR	70%	10%	20%
MK	100%	0%	0%
US	50%	30%	20%
JA	50%	30%	20%
CA	100%	0%	0%
AU	20%	10%	70%
NZ	80%	20%	0%
RS	80%	20%	0%
RA	100%	0%	0%
CN	50%	25%	25%
IN	50%	25%	25%
MX	70%	10%	20%
BR	100%	0%	0%
AR	100%	0%	0%
CO	100%	0%	0%
LA	100%	0%	0%
KR	60%	30%	10%
TW	30%	30%	40%
ID	30%	20%	50%
AS	30%	30%	40%
OP	50%	30%	20%
RW	100%	0%	0%
UE	50%	50%	0%
SD	30%	30%	40%
NG	50%	50%	0%
SA	50%	50%	0%
ON	30%	30%	40%
OC	30%	30%	40%
MY	30%	30%	40%
KZ	50%	0%	50%
AN	30%	30%	40%
AC	50%	0%	50%
AW	30%	30%	40%
AE	30%	30%	40%
ZA	50%	50%	0%
EG	30%	30%	40%
DC	50%	0%	50%
KE	30%	30%	40%
UA	30%	10%	60%
PK	30%	10%	60%

Cost factors of renewable electricity generation

The tables below display the starting CAPEX, OPEX costs and load factors for onshore wind (Table 8), offshore wind (Table 9) and solar PV (Table 10). These estimates are based on a baseline run (akin to current policies scenario) of FTT:Power. The estimates include endogenous learning-by-doing effects, storage costs and resource constraint effects. For more information we refer to Nijsse, et al.[29] The initial estimates stem from the GNESTE database.[30]

Table 8: Cost factors for onshore wind power

Region	CAPEX in 2025 ($/kW)	CAPEX in 2050 ($/kW)	OPEX in 2025 ($/MWh)	OPEX in 2050 ($/MWh)	Load factor in 2025 (%)	Load factor in 2050 (%)
BE	1203	819	14.2	14.2	26%	23%
DK	1611	1097	7.3	7.3	37%	35%
DE	1276	869	15.7	15.7	26%	24%
EL	1140	776	14.2	14.2	37%	33%
ES	844	575	14.2	14.2	20%	17%
FR	1273	867	14.2	14.2	31%	28%
IE	1309	891	4.7	4.7	23%	23%
IT	998	680	14.2	14.2	31%	25%
LX	1103	751	14.2	14.2	27%	23%
NL	1240	844	14.2	14.2	31%	27%
AT	1220	830	14.2	14.2	23%	20%
PT	1490	1014	14.2	14.2	19%	18%
FI	1033	703	14.2	14.2	33%	32%
SW	1119	762	6.4	6.4	31%	33%
UK	928	632	14.2	14.2	38%	39%
CZ	1103	751	14.2	14.2	32%	26%
EN	1103	751	14.2	14.2	34%	33%
CY	1636	1114	14.2	14.2	31%	26%
LV	1103	751	14.2	14.2	39%	37%
LT	1103	751	14.2	14.2	36%	33%
HU	1103	751	14.2	14.2	26%	23%
MT	1103	751	14.2	14.2	42%	32%
PL	1224	833	14.2	14.2	26%	22%
SI	1103	751	14.2	14.2	30%	25%
SK	1103	751	14.2	14.2	32%	29%
BG	1187	808	9.3	9.3	27%	25%
RO	1187	808	9.3	9.3	25%	25%
NO	1246	848	10.4	10.4	38%	35%
CH	1103	751	14.2	14.2	31%	28%
IS	1103	751	14.2	14.2	46%	45%
HR	1110	756	14.2	14.2	28%	29%

[30] Hatton, L., et al. (2024). The global and national energy systems techno-economic (GNESTE) database: cost and performance data for electricity generation and storage technologies.

Region	CAPEX in 2025 ($/kW)	CAPEX in 2050 ($/kW)	OPEX in 2025 ($/MWh)	OPEX in 2050 ($/MWh)	Load factor in 2025 (%)	Load factor in 2050 (%)
TR	1046	712	5.9	5.9	29%	28%
MK	1103	751	14.2	14.2	41%	43%
US	1094	745	8.8	8.8	43%	40%
JA	1738	1183	34.5	34.5	21%	21%
CA	1035	705	4.8	4.8	41%	42%
AU	1146	780	8.1	8.1	40%	37%
NZ	1224	833	9.3	9.3	40%	43%
RS	1251	852	9.3	9.3	27%	26%
RA	1187	808	9.3	9.3	27%	27%
CN	719	489	7.8	7.8	19%	14%
IN	881	600	9.8	9.8	23%	18%
MX	1150	783	5.4	5.4	42%	36%
BR	787	536	3.1	3.1	46%	43%
AR	1352	920	3.7	3.7	56%	57%
CO	1062	723	4.6	4.6	36%	36%
LA	1118	761	3.6	3.6	43%	39%
KR	1495	1018	16.5	16.5	17%	13%
TW	1187	808	9.3	9.3	18%	18%
ID	1801	1226	8.0	8.0	24%	22%
AS	1206	821	11.9	11.9	21%	18%
OP	936	637	9.3	9.3	37%	33%
RW	1187	808	9.3	9.3	42%	39%
UE	1169	796	14.2	14.2	27%	27%
SD	936	637	9.3	9.3	35%	31%
NG	1187	808	9.3	9.3	30%	30%
SA	1263	860	8.3	8.3	37%	32%
ON	936	637	9.3	9.3	40%	37%
OC	1187	808	9.3	9.3	30%	30%
MY	855	582	9.3	9.3	30%	30%
KZ	1187	808	9.3	9.3	43%	41%
AN	1167	794	9.3	9.3	43%	43%
AC	1187	808	9.3	9.3	40%	37%
AW	1187	808	9.3	9.3	42%	40%
AE	1619	1102	9.3	9.3	41%	40%
ZA	1187	808	9.3	9.3	42%	40%
EG	1022	696	9.3	9.3	42%	37%
DC	1187	808	9.3	9.3	30%	30%
KE	1187	808	9.3	9.3	39%	37%
UA	936	637	9.3	9.3	24%	37%
PK	941	641	9.3	9.3	35%	31%

Table 9: Cost factors for offshore wind power

Region	CAPEX in 2025 ($/kW)	CAPEX in 2050 ($/kW)	OPEX in 2025 ($/MWh)	OPEX in 2050 ($/MWh)	Load factor in 2025 (%)	Load factor in 2050 (%)
BE	2893	2345	15.9	15.9	35%	35%
DK	2146	1740	11.6	11.6	49%	45%
DE	2129	1726	14.4	14.4	46%	43%
EL	2308	1871	16.1	16.1	35%	35%
ES	2308	1871	16.1	16.1	40%	40%
FR	2308	1871	16.1	16.1	48%	48%
IE	2308	1871	16.1	16.1	57%	59%
IT	2308	1871	16.1	16.1	35%	35%
LX	2308	1871	16.1	16.1	30%	30%
NL	1886	1529	13.5	13.5	44%	41%
AT	2308	1871	16.1	16.1	30%	30%
PT	2308	1871	16.1	16.1	39%	39%
FI	2308	1871	16.1	16.1	51%	51%
SW	2308	1871	16.1	16.1	51%	51%
UK	2524	2046	12.0	12.0	52%	50%
CZ	2308	1871	16.1	16.1	30%	30%
EN	2308	1871	16.1	16.1	50%	49%
CY	2308	1871	16.1	16.1	27%	26%
LV	2308	1871	16.1	16.1	51%	51%
LT	2308	1871	16.1	16.1	51%	48%
HU	2308	1871	16.1	16.1	30%	30%
MT	2308	1871	16.1	16.1	18%	7%
PL	2308	1871	16.1	16.1	51%	51%
SI	2308	1871	16.1	16.1	30%	30%
SK	2308	1871	16.1	16.1	30%	30%
BG	3074	2492	16.1	16.1	31%	31%
RO	3074	2492	16.1	16.1	5%	5%
NO	2308	1871	16.1	16.1	49%	48%
CH	2308	1871	16.1	16.1	30%	30%
IS	2308	1871	16.1	16.1	57%	57%
HR	2308	1871	16.1	16.1	35%	35%
TR	4465	3620	16.1	16.1	38%	40%
MK	2308	1871	16.1	16.1	30%	30%
US	2713	2199	15.0	15.0	48%	48%
JA	4066	3296	36.3	36.3	30%	30%
CA	4746	3848	16.1	16.1	48%	48%

Region	CAPEX in 2025 ($/kW)	CAPEX in 2050 ($/kW)	OPEX in 2025 ($/MWh)	OPEX in 2050 ($/MWh)	Load factor in 2025 (%)	Load factor in 2050 (%)
AU	2649	2148	16.1	16.1	51%	49%
NZ	4036	3272	16.1	16.1	48%	51%
RS	4471	3624	13.5	13.5	40%	40%
RA	3074	2492	13.5	13.5	30%	30%
CN	1743	1413	11.1	11.1	32%	28%
IN	4237	3435	13.5	13.5	35%	35%
MX	4746	3848	13.5	13.5	48%	48%
BR	4410	3575	13.5	13.5	53%	53%
AR	4410	3575	13.5	13.5	60%	60%
CO	4410	3575	13.5	13.5	39%	39%
LA	4410	3575	13.5	13.5	48%	48%
KR	5122	4152	16.1	16.1	29%	29%
TW	4410	3575	26.2	26.2	28%	29%
ID	4432	3593	13.5	13.5	29%	29%
AS	4432	3593	13.5	13.5	29%	29%
OP	4465	3620	13.5	13.5	40%	40%
RW	2970	2407	13.5	13.5	37%	37%
UE	2308	1871	13.5	13.5	40%	40%
SD	4465	3620	13.5	13.5	40%	40%
NG	3074	2492	13.5	13.5	30%	30%
SA	3074	2492	13.5	13.5	30%	30%
ON	4465	3620	13.5	13.5	30%	28%
OC	3074	2492	13.5	13.5	30%	30%
MY	4432	3593	13.5	13.5	30%	30%
KZ	3074	2492	13.5	13.5	30%	30%
AN	3074	2492	13.5	13.5	30%	30%
AC	3074	2492	13.5	13.5	30%	30%
AW	3074	2492	13.5	13.5	30%	30%
AE	3074	2492	13.5	13.5	30%	30%
ZA	3074	2492	13.5	13.5	30%	17%
EG	4465	3620	13.5	13.5	30%	30%
DC	3074	2492	13.5	13.5	30%	30%
KE	3074	2492	13.5	13.5	30%	30%
UA	4465	3620	13.5	13.5	30%	29%
PK	3074	2492	13.5	13.5	30%	30%

Table 10: Cost factors for solar PV

Region	CAPEX in 2025 ($/kW)	CAPEX in 2050 ($/kW)	OPEX in 2025 ($/MWh)	OPEX in 2050 ($/MWh)	Load factor in 2025 (%)	Load factor in 2050 (%)
BE	812	377	7.3	7.3	11%	8%
DK	815	378	7.3	7.3	9%	8%
DE	499	231	8.9	8.9	9%	8%
EL	427	198	7.3	7.3	15%	14%
ES	458	212	5.2	5.2	16%	16%
FR	652	302	7.5	7.5	13%	12%
IE	969	449	7.3	7.3	10%	9%
IT	561	260	6.1	6.1	14%	13%
LX	812	377	7.3	7.3	12%	10%
NL	514	238	7.3	7.3	8%	6%
AT	499	231	7.3	7.3	12%	11%
PT	494	229	7.3	7.3	16%	16%
FI	812	377	7.3	7.3	9%	7%
SW	812	377	7.3	7.3	9%	8%
UK	637	295	9.3	9.3	10%	9%
CZ	812	377	7.3	7.3	12%	11%
EN	639	296	7.3	7.3	9%	9%
CY	583	270	7.3	7.3	14%	12%
LV	812	377	7.3	7.3	10%	9%
LT	812	377	7.3	7.3	10%	9%
HU	906	420	7.3	7.3	14%	12%
MT	812	377	7.3	7.3	11%	8%
PL	478	222	7.3	7.3	9%	9%
SI	685	318	7.3	7.3	15%	13%
SK	812	377	7.3	7.3	14%	13%
BG	570	264	7.3	7.3	15%	14%
RO	614	285	7.3	7.3	14%	13%
NO	812	377	7.3	7.3	9%	8%
CH	812	377	7.3	7.3	13%	11%
IS	812	377	7.3	7.3	7%	6%
HR	870	403	7.3	7.3	16%	14%
TR	488	226	3.2	3.2	16%	16%
MK	812	377	7.3	7.3	16%	15%
US	757	351	6.2	6.2	20%	21%
JA	1280	593	16.0	16.0	14%	12%
CA	913	423	8.0	8.0	17%	16%
AU	675	313	5.4	5.4	24%	24%
NZ	646	299	7.3	7.3	12%	13%
RS	1214	563	7.3	7.3	13%	12%

Region	CAPEX in 2025 ($/kW)	CAPEX in 2050 ($/kW)	OPEX in 2025 ($/MWh)	OPEX in 2050 ($/MWh)	Load factor in 2025 (%)	Load factor in 2050 (%)
RA	646	299	7.3	7.3	13%	11%
CN	458	212	3.1	3.1	13%	14%
IN	486	225	2.4	2.4	16%	16%
MX	717	332	5.3	5.3	20%	20%
BR	496	230	4.0	4.0	22%	21%
AR	673	312	5.7	5.7	23%	21%
CO	599	277	5.8	5.8	16%	15%
LA	651	302	5.2	5.2	22%	22%
KR	823	381	19.4	19.4	13%	11%
TW	646	299	7.3	7.3	13%	11%
ID	683	316	7.6	7.6	15%	13%
AS	569	264	8.3	8.3	14%	14%
OP	646	299	7.3	7.3	18%	17%
RW	464	215	5.4	5.4	16%	19%
UE	812	377	7.3	7.3	15%	14%
SD	542	251	7.3	7.3	16%	17%
NG	646	299	7.3	7.3	17%	17%
SA	857	397	5.1	5.1	19%	19%
ON	646	299	7.3	7.3	17%	17%
OC	646	299	7.3	7.3	19%	18%
MY	522	242	7.2	7.2	14%	14%
KZ	646	299	7.3	7.3	15%	13%
AN	646	299	7.3	7.3	18%	18%
AC	646	299	7.3	7.3	18%	18%
AW	657	304	5.9	5.9	19%	18%
AE	1037	481	12.2	12.2	18%	16%
ZA	500	232	1.4	1.4	20%	17%
EG	646	299	7.3	7.3	18%	17%
DC	646	299	7.3	7.3	14%	17%
KE	899	417	9.5	9.5	17%	17%
UA	410	190	5.7	5.7	16%	16%
PK	646	299	7.3	7.3	24%	25%

Fixed domestic utilisation of capacity

In the model we assume a certain percentage of demand that must be sourced domestically, provided that sufficient capacity exists. This bypasses the cost-supply curve approach. Any remaining unmet demand and unutilised capacity is passed to the cost-supply curve.

Table 11: Assumed domestic utilisation rate

Region	Domestic utilisation rate
EU, North America, and ANZ	60%
RoW	85%

EEIST

Economics of Energy Innovation and System Transition

The Economics of Energy Innovation and System Transition (EEIST) project develops cutting-edge energy innovation analysis to support government decision making around low-carbon innovation and technological change. By engaging with policymakers and stakeholders in Brazil, China, India, the UK and the EU, the project aims to contribute to the economic development of emerging nations and support sustainable development globally.

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