Background paper. Rollout of international hydrogen trade for the EU

Overview

Published on 18 May 2022, the [REPowerEU Communication] from the European Commission envisages a rapid scale up of the role of hydrogen to 2030, in particular as a substitute for imported fossil fuels. The stated plan is to enter the 2030s with 250 bcm less natural gas demand in the EU compared with 2020; a 60% reduction. On 30 May 2022, the European Council agreed to ban seaborne imports of crude and oil products from Russia, with effect from the end of 2022 and early 2023, respectively. The hydrogen target to meet these goals goes far beyond the 5.6 million tonnes of hydrogen from renewable electricity that was included in the Fit for 55 package in 2021, raising it to 20 million tonnes consumed within the EU in 2030. Of the additional 14.4 million tonnes, 10 million tonnes are foreseen to be imported from third countries.

Given that global hydrogen production from low emissions electricity currently stands below 0.025 million tonnes per year, the pace of scale-up to meet the targets is very ambitious. More than previous policy documents, REPowerEU puts the focus on *projects* rather than *potential* or *net-zero requirements*. Whether or not gas and oil demand can be significantly reduced by the deployment of low-emissions hydrogen will depend on whether investment into real-world projects can be mobilised in time.

For example, it will require a coordinated sequence of major infrastructure projects, each of which might consist of a value chain including renewable electricity generation (with individual plants of 1 GW or more), new equipment for accommodating hydrogen in end-uses (thousands of tonnes per year at a time), hydrogen production, hydrogen transport and hydrogen storage. To bring that full value chain online by 2030 will likely require all the conditions to be in place for the first investment decisions by 2026 at the latest. For many projects, a pathway that minimises risk might involve stepwise expansion to 1 GW, starting with around 100 MW. If so, the first stages may need to start construction within two years from now. For that to happen, a swathe of enabling conditions – safety regulations, contracting models, certification systems, insurance products, market-based operational support, permitting and technical guarantees – will need to be finalised in a way that does not put projects at risk from future updates and improvements.

Another implication of the REPowerEU targets for hydrogen is that all member states will need to take critical decisions in the coming year or two. The targets are out of the reach of a small number of leading EU member states acting alone. Reaching 20 million tonnes per year will require almost all EU member states to make significant investments within their borders, and also create the conditions for investments in hydrogen supply from outside the EU.

The focus of this background paper, and the workshop it informs, is therefore project-based and applicable to all countries. It seeks to review some of the policy and technical considerations behind four practical questions:

- In what sectors can hydrogen displace large amounts natural gas and other fossil fuels in a hurry?
- How quickly can significant quantities of hydrogen and hydrogen-based fuels be imported, and in what configurations?
- What policies are still needed to enable investments in low-emissions hydrogen supply for export within or to the EU?
- How will the necessary EU infrastructure for importing hydrogen get built and on what terms?

The good news is that hydrogen has never been in a more advantageous position for attracting investment. The disastrous social and political backdrops of the Covid-19 pandemic and the invasion of Ukraine have changed the nature of energy policy concerns in favour of rapid investment in clean, secure energy infrastructure, espeically that which can help eliminate gas and oil imports. At the same time, medium-term oil, gas and electricity price forecasts have risen, somewhat narrowing the gap between hydrogen prices and those of competing fuels. Expectations for hydrogen supply and use in a variety of end-uses have risen dramatically, especially in Europe. Large-scale projects for producing and shipping hydrogen (and hydrogen-based fuels such as ammonia) now have the attention of serious consortiums and investors across all continents. Many of the world's largest companies and energy-exporting countries have reached the conclusion that they cannot afford to not be part of the first wave of projects, shifting their stance away from a wait-and-see perspective.

However, achieving the REPowerEU targets also faces challenges. While high fossil fuel prices can make low-emissions hydrogen more competitive by comparison, they are prompting concerns about high cost energy more generally: governments are protecting consumers from energy prices below the lowest costs of low-emissions hydrogen. Investment in hydrogen use will need an even sharper focus on the situations in which prices can be either accommodated or subsidised despite higher input costs for businesses in general.

Rising interest rates pose an additional concern because they will increase hydrogen project costs and potentially exacerbate cost gaps between advanced economies and the emerging and developing world. Higher project costs lead to higher hydrogen prices and a risk of disillusion if widely publicised cost targets are unfulfilled. Costs may also rise if global supply chains fragment and stifle trade in equipment and knowledge. Additionally, the urgency with which the EU and other countries wish to remake their energy supplies and trade patterns raises concerns about the ability of policy makers and companies to deliver everything in parallel, from new gas supplies to energy efficiency, renewables, hydrogen and electrification. Given that it may yet take years for policies to align, some project developers are expecting to take investment decisions without having all pieces of the regulatory puzzle in place, further raising risks.

A pragmatic approach to policy is therefore needed from all EU member states as they take steps up a steep learning curve, with some starting from a higher position than others.

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1. Basics and definitions

What are the main ways that hydrogen can substitute for fossil fuels?

Hydrogen is considered a versatile energy carrier because it can be used in a variety of different end-uses. This is of particular importance for enabling the substitution of fossil fuels with renewable electricity, which is currently incompatible with many uses of natural gas or oil products without conversion of the electricity to a molecular fuel such as hydrogen.

There are three broad ways that hydrogen can help meet a goal to move away from natural gas or oil use:

- Use hydrogen from non-fossil sources (i.e. renewable or nuclear electricity or biomass) in an end-use that otherwise uses natural gas or oil.
- Convert hydrogen to a hydrogen-based fuel with a lower (or ideally, no) fossil carbon content and use it in an end-use that otherwise uses natural gas or oil.
- Use hydrogen from non-fossil sources as an input to an industrial process that would otherwise use hydrogen from fossil-based sources.

Alongside near-term measures including energy efficiency and accelerated deployment of renewable electricity on the grid, these three ways can help meet the objective of reducing reliance on a specific type or provider of fossil fuels by 2030. Ultimately, however, a delicate balance of factors will be required to reduce the EU's greenhouse gas emissions footprint, fossil fuel reliance, energy price volatility and dependence on specific energy exporters.

In some cases, these averarching policy goals may also be served by importing hydrogen made using fossil fuel supplies from a secure, gas-producing country and with a high rate of CO_2 capture and storage. This could apply if the fuel source is natural gas that would otherwise not have come onto international markets. In other cases, hydrogen produced using of renewable electricity without long-term offtake agreements with specific suppliers may continue to be exposed to volatile natural gas prices though electricity markets.

Naming conventions

Key hydrogen terminology and how it is used in this paper

Term	Definition
Low-emissions hydrogen	To be low-emissions hydrogen, either the emissions associated with fossil fuel-based hydrogen production must be prevented (e.g. by carbon capture, utilisation and storage) or the electricity for hydrogen production from water must be low-emissions electricity (e.g. renewable or nuclear power). Can also include hydrogen from biomass via thermochemical routes, or high-temperature or other water-splitting using nuclear or solar energy.
Low-emissions electrolysis hydrogen	The subset of low-emissions hydrogen that is produced by electrolysis of water using renewable or nuclear electricity. Some people refer to this as green (renewable electricity) or pink (nuclear electricity) hydrogen. Nuclear-based electrolysis hydrogen for export to the EU is unlikely this decade. For displacing fossil fuel imports, low-emissions electrolysis hydrogen is the only candidate for low-emissions hydrogen production within the EU.
Low-emissions fossil hydrogen	The subset of low-emissions hydrogen that is produced from fossil fuels, such as natural gas, with high rates of CO_2 capture and low levels of upstream methane emissions (to bring down the life cycle greenhouse gas impact to a similar level to low-emissions electrolysis hydrogen). Some people refer to this as blue hydrogen but they typically also include lower CO_2 capture rates and higher methane emissions within definitions of blue hydrogen. Could also include methane pyrolysis, a technology that is unlikely to be available for exports to the EU this decade.
Low-emissions hydrogen from bioenergy	The subset of low-emissions hydrogen that is produced by using heat treatment (such as gasification) to extract the hydrogen content from biomass and water. This technology is unlikely to be available for exports to the EU this decade.
Low-emissions hydrogen-based fuels	The set of fuels that can be produced from low-emissions hydrogen for ease of transport and use, including ammonia, synthetic hydrocarbons, methanol. Among these, ammonia is the only one that does not contain carbon. Because the others would need to avoid using fossil carbon in their synthesis, and because non-fossil carbon sources are not expected to be available at satisfactory scales and costs this decade, ammonia is the most likely such fuel to be available for exports to the EU this decade.

Conversion rules of thumb

Hydrogen is usually traded in mass units (i.e. kilograms), which has led to this being the most common way that supply, demand and prices are quoted in energy discussions. However, the units for hydrogen are not intuitive and some simple conversions can help estimate the requirements for hydrogen infrastructure to substite fossil fuels.

Examples of conversions include:

- EU gas imports from Russia in 2019 ≈ 47 million tonnes of hydrogen per year (Mt H_2/yr) in energy equivalent terms
- EU demand for hydrogen in 2020 ≈ 7 Mt H_2 ≈ 21 bcm natural gas
- Total global H2 production in 2020 ≈ 90 Mt H_2 ≈ 270 bcm natural gas
- June 2022 TTF gas prices of EUR 30/MBtu ≈ EUR 3.4/kg H_2
- US Earthshot 2031 target hydrogen production cost of USD 1.5/kg H_2 ≈ USD 13/MBtu (before taxes etc.)
- EUR 2/litre gasoline (after tax) ≈ EUR 3.7/kg H_2 (before100% tax)

Converting between hydrogen and natural gas

Starting unit	Rule of thumb conversion	Relevant constants
1 Mt H_2	3 bcm natural gas	1 bcm = 11.1 TWh 1 Mt H_2 = 33.4 TWh
USD 1/kg H_2	USD 9/MBtu natural gas	1 MBtu = 293 kWh 1 kg H_2 = 33.4 kWh

Note: Energy values given in lower heating value (LHV) terms. Mt = million tonnes.

Converting between hydrogen and coal

Starting unit	Rule of thumb conversion	Relevant constants
1 Mt H_2	4.1 Mt coal	1 Mt coal = 8.1 TWh
1 Mt coal	1.5 Mt NH_3	
USD 1/kg H_2	USD 245/t coal	
USD 1/t NH_3	USD 1.55/t coal	

Note: Energy values given in lower heating value (LHV) terms. Mt = million tonnes.

Converting between hydrogen and oil

Starting unit	Rule of thumb conversion	Relevant constants
1 mb/d crude oil	17 Mt H_2/year 110 Mt NH_3/year 105 Mt MeOH/year	1 bbl crude oil = 1.6 TWh 1 Mt NH_3 = 5.3 TWh 1 Mt MeOH = 5.5 TWh
USD 1/litre gasoline	USD 3.7/kg H_2	1 litre gasoline = 9 kWh LHV
USD 1/kg H_2	USD 50/bbl crude oil	
USD 100/t NH_3	USD 30/bbl crude oil USD 230/tonne marine fuel oil	1 kg marine fuel oil = 12 kWh LHV
USD 100/t MeOH	USD 29/bbl crude oil USD 220/tonne marine fuel oill	

Note: Energy values given in lower heating value (LHV) terms. Mt = million tonnes. MeOH = methanol

Converting between hydrogen and hydrogen-based fuel units

Starting unit	Rule of thumb conversion	Relevant constants
1 Mt H_2/year	10 GW H_2 electrolysis capacity 15 GW renewables input capacity 50 TWh renewable electricity input 4.3 bcm natural gas input (with CCUS)	70% electrolyser efficiency 40-70% electrolyser load factor 50% oversizing of hybrid PV and wind installation 0.69% efficiency of hydrogen production from natural gas with CCUS
1 Mt NH_3/year	1.8 GW H_2 electrolysis capacity 2.7 GW renewables input capacity 9.9 TWh renewable electricity input 0.8 bcm natural gas input (with CCUS)	87% efficiency of conversion of H_2 to NH_3 1 Mt H_2 = 6.4 Mt NH_3 (energy equivalent)
USD 1/kg H_2	USD 160/t NH_3	

Note: Electrolysis capacity given in electrical input terms.

2. In what sectors can hydrogen displace large amounts of natural gas and other fossil fuels by 2030?

Determining potential and identifying project opportunities

Scaling up hydrogen rapidly in the 2020s depends on the identification of large projects (or aggregated groups of smaller projects) that can advance quickly to investment decisions in a few years.

This is a different consideration from many analyses of hydrogen's potential. Many publications and roadmaps take a longer term view of factors such as: the possblie extent of the resource base for low-cost low-emissions electricity in the 2030s and beyond; the expected sectoral demand for hydrogen to meet net zero targets in 2050; the need for grid flexibility in a high renewable electricity scenario; and the relative competitiveness of hydrogen produced in different locations once a trade infrastructure is already well established.

The projects that will get built this decade should be highly compatible with these long-term considerations, especially in terms of the key nodes of hydrogen distribution infrastructure, but they will also meet the following core criteria:

- Can deliver hydrogen to an end-use that can absorb large quantities of hydrogen (or a hydrogen-based fuel) from a new source without major industrial dislocations and with guarantees of multi-year offtake
- Can undertake all the required engineering work and acquire all the necessary permits within 3-4 years.
- Can meet the relevant standards for certification of the lifecycle environmental impact of the delivered hydrogen
- Can access the necessary financing, or co-financing, from private company balance sheets, project finance or special purpose vehicles.
- Minimise value chain risk by reducing the number of new technologies, business models and separate contracts required.

Among these considerations, the first is perhaps the most important. Each EU member state has a different configuration of sectors that could use low-emissions hydrogen, which in turn face different considerations in terms of the fossil fuel assets that might be devalued as a result and the competeveness of hydrogen among clean energy options. The following pages review some of these issues.

Speed of execution may also be crucially important if the latest draft of the European Commission's rules for eligibilty of hydrogen as a renewable fuel of non-biological origin (RFNBO) are adopted as the industry standard and the main driver of policy support. This section of the paper concludes with a review of the conditions set out in this document.

Sectoral considerations for substituting fossil fuels with low-emissions hydrogen

Options and issues for scaling up hydrogen use in the EU, by sector

Sector/application	Substituted fuel	Detail	Estimate of current EU demand	To reach 1 Mt H_2 demand
Refining	Natural gas or oil	Low-emissions hydrogen can be used instead of hydrogen produced in the EU from natural gas or as a refinery product. • Advantages: Substitution is relatively straightforward; demand at a single facility is large (up to 0.2 Mt H_2/yr); refinery sites often have room for electrolysers, are at ports and have experience with hydrogen handling, including pipelines; the existing hydrogen course can be retained to help balance variable electrolyser output; operators are under pressure to reduce scope 1 & 2 emissions; refineries are distributed around the EU, including Austria, Greece, Poland, Portugal, Slovakia, Spain. • Considerations: New hydrogen supplies will reduce output of existing natural gas-based plants, which have associated jobs and may still need to stay online for flexibility; not all refineries have high hydrogen demand as some simple facilities have less hydrotreating and hydrocracking.	~ 3.5 Mt H_2	5 big refineries
Fertilisers	Natural gas	Low-emissions hydrogen can be used instead of hydrogen produced from natural gas in ammonia production. • Advantages: Substitution is relatively straightforward; potential demand at a single facility is significant (around 0.02 Mt H_2/yr); the existing hydrogen course can be retained to help balance variable electrolyser output; operators are under pressure to reduce scope 1 & 2 emissions; plants are distributed around the EU; the market for ammonia will persist for a long time and is not tied to climate action. • Considerations: Often only 35% of the hydrogen or less can be replaced due to the common practice of converting ammonia to urea using carbon from the integrated fossil-fuel-to-hydrogen production process; for imports, it makes more sense to import ammonia than hydrogen for fertiliser production, which would lead to closure of EU ammonia facilities; some fertiliser plants operate seasonally and may need to be paired with other uses to make a strong investment case for new hydrogen supply; new hydrogen supplies will reduce output of existing natural gas-based plants, which have associated jobs and may still need to stay online for flexibility.	~ 2.8 Mt H_2	50 average size fertiliser plants

Sector/application	Substituted fuel	Detail	Estimate of current EU demand	To reach 1 Mt H_2 demand
Iron and steel	Natural gas or coal	Hydrogen can substitute fossil fuels in steelmaking in several ways. In the near term, it can be blended with natural gas in direct reduced iron (DRI) plants, injected into blast furnaces alongside coke, used for high temperature heat in steel finishing; added to fuel gases at integrated steel mills. There is considerable momentum towards converting EU steel production from blast furnaces to 100% hydrogen-based DRI systems, starting with plants in Sweden and Germany by the end of the 2020s. • Advantages: New H_2-DRI plants would be very large single demand sources (~1 Mt H_2/yr); using hydrogen for high-temperature heat for steel finishing is demonstrated, not highly disruptive to operations and an electrolyser could provide a hedge against gas prices as well as supplying necessary oxygen to the combustion chamber; steel finishing is quite distributed around the EU; countries are keen to protect and maintain steel production; one of the few sectors where commercial interests would pay a premium for low-emissions steel (e.g. carmakers). • Considerations: Injecting hydrogen into blast furnaces reduces coal demand, not oil or gas demand; only 2-3 H_2-DRI plants are considered feasible in the EU by 2030 and they require unprecedented electricity offtake contracts; there are few existing DRI plants in the EU for blending hydrogen to reduce gas demand, and new natural gas DRI plants look less attractive in light of the emphasis on reducing gas demand; integrated steel mills are often configured to burn a mixture of hydrogen and fossil carbon monoxide that is a by-product of other processes and cannot readily be converted to hydrogen; for imports, there is an incentive for exporters to produce hot briquetted iron (from DRI) outside the EU instead of exporting hydrogen for DRI in the EU – this would keep the final stages of steel production in the EU but lead to closure of some EU heavy industry, potentially including the steel sector's best paid jobs in hot metal production.	~ 0.1 Mt H_2 (pure hydrogen)	1 new H_2-DRI plant (or 10-50 at different blending levels)
Chemicals	Natural gas	Low-emissions hydrogen can be used instead of hydrogen produced in the EU from natural gas for production of chemicals such as methanol. • Advantages: The opportunity is especially great where chemical plants buy merchant hydrogen that is not integrated with their other onsite processes; chemical sites are often co-located with other hydrogen demand, are at ports and have experience with hydrogen handling, including pipelines; operators are under pressure to reduce scope 1 & 2 emissions. • Considerations: Chemical plants do not have very high hydrogen demand, except for methanol; methanol requires carbon inputs that normally come with hydrogen	~ 0.3 Mt H_2	>50 typical chemical plants

Sector/application	Substituted fuel	Detail	Estimate of current EU demand	To reach 1 Mt H_2 demand
		from natural gas reformation, so new sources of carbon would be needed; The EU is not a major methanol producer internationally, though this could change if it is a preferred option for ships; new hydrogen supplies will reduce output of existing natural gas-based plants, which have associated jobs and may still need to stay online for flexibility.		
Electricity	Natural gas	Low-emissions hydrogen can be co-fired up to around 50% in gas turbines. A small number of very modern turbines are already certified for using 100% hydrogen. • Advantages: Directly reduces natural gas demand without compromising flexibility; converting a single unit to 100% hydrogen could use a significant amount of hydrogen (0.05 Mt H_2/yr); does not impact the value of any other existing infrastructure except gas supply; existing policy tools of CO_2 pricing and CFDs are suited to this task; CCGTs are well spread across the EU. • Considerations: Higher blends above 20% in gas turbines are not yet proven at scale; ensuring flexible operation by 2030 requires significant investment in local hydrogen storage; there are current discussions about reforming peak electricity remuneration, and a hydrogen turbine would be likely to have the highest marginal costs on the grid.	-	20 CCGTs at 100% (or >100 at 20% blend)
Electricity	Coal (and some natural gas)	Ammonia can be co-fired with coal to reduce coal combustion and, if load factors rise as a result, could displace natural gas fired power plants. • Advantages: Can directly use ammonia imports without cracking if that is the preferred export mode; does not impact the value of any other existing infrastructure except gas supply; existing policy tools of CO_2 pricing and CFDs are suited to this task. • Considerations: Mostly displaces coal; the future of coal plants is not guaranteed so signing long-term contracts for blending may be challenging; only relatively small shares of ammonia have been proven so far, which would not displace large amounts of oil or gas; new ammonia storage would be required; coal-plants s are well spread across the EU and many are located at ports.	-	>100 for ammonia blending with coal
Electricity	Oil	Fuel cell systems can be installed and powered by low-emissions hydrogen to reduce the use of diesel gensets for backup power, e.g. at data centres or hospitals. • Advantages: Relatively easy to install; suppliers already exist; small amounts of hydrogen mean it can be delivered to an above-ground tank by truck; users are well distributed across EU. • Considerations: Impact on oil use is likely to be small due to small units and low load factors (demand of ~6 t H_2/yr per diesel genset).	-	150 000 backup diesel gensets

Sector/application	Substituted fuel	Detail	Estimate of current EU demand	To reach 1 Mt H_2 demand
Heating and other distributed uses	Natural gas	Up to 5% hydrogen by volume could be blended into natural gas pipelines and the resulting blend used in buildings or industrial processes without major investments. • Advantages: A single city distribution grid may supply a significant amount of hydrogen at a 5% blend (e.g. 0.01 Mt H_2/yr). At low blends, no upgrade of user equipment needed; infrastructure already exists; tackles a highly distributed source of gas demand that exists across the EU; helps to prepare the ground for conversions of pipelines to 100% hydrogen after 2030; if new pipelines are needed, they could follow the rights of way of existing pipelines, potentially easing permitting. • Considerations: The demand profile is highly seasonal and hydrogen supply will likely vary with renewable electricity supply, which means that avoiding exceeding 5% at a given time would mean blending much less on average over a year and may require hydrogen storage; strategic injection points would be required (at distribution level as most transmission pipelines are not suitable); upgrades to distribution infrastructure, including meters, compression and pipelines may be needed; hydrogen leaks can contribute to climate change and higher costs.	-	100 city distribution grids at 5% blend
District heat	Natural gas	Low-emissions hydrogen can be co-fired up to around 50% in gas turbines and it may be possible to blend ammonia with biomass. In some cases, fuel cell cogeneration plants could be installed by 2030. • Advantages: Facilitates heat decarbonisation without any end-user intervention; a single unit could take a significant amount of hydrogen (e.g. 0.02 Mt H_2/yr); cogeneration plants are often located at industrial sites at ports and can tackle high-temperature heat via steam; higher load factors are possible with cogeneration. • Considerations: buildings heat is a seasonal demand source, not necessarily aligned with renewable electricity output.	-	50 cogen plants converted to hydrogen
Planes	Oil	Synthetic kerosene is a hydrogen-based fuel that has the potential to reduce aviation emissions, especially if produced with non-fossil carbon. The first pilot project started production in 2021, and several full-scale plants could be achieved by 2030. • Advantages: Facilitates aviation decarbonisation without any end-user intervention; some EU airports are near ports or renewable energy sources; some airlines will be willing to pay a premium to get low-emissions fuel; not limited to major N. Sea economies. • Considerations: Few plants can be expected by 2030; for imports, it may be more cost effective for importers and exporters to trade the finished fuel, not the	-	40 commercial synthetic kerosene plants

Sector/application	Substituted fuel	Detail	Estimate of current EU demand	To reach 1 Mt H_2 demand
		hydrogen, in which case airlines may prefer to refuel in the country of hydrogen production, rather than import the fuel by ship first, resulting in value from fuel value chains moving outside the EU.		
Ships	Oil	The hydrogen-based fuels ammonia and methanol are the main non-bioenergy candidates for reducing fossil fuel use by ships. • Advantages: A small fleet of container ships can have a significant demand (e.g. 12 ships could use 0.1 Mt H_2/yr equivalent). For coastal countries without major industrial hydrogen users, this represents a significant opportunity to start using hydrogen-based fuels; ships already run on methanol and new ships designed to be powered by these fuels have already been ordered in small quantities; EU has other complementary goals for maritime transport. • Considerations: Greenhouse gas reductions from international shipping from EU ports are generally not credited to the EU country; it will take time to ramp up ship and engine production; ammonia powertrains for ships are not expected to be available until right at the end of this decade; ammonia safety concerns persist within the sector.	-	1 500 ships
Trucks	Oil	Although FCEV trucks are not yet available to buy, they are under development. • Advantages: Trucks that operate at port facilities could be prime candidates for using imported hydrogen and reducing local air pollution, although those making short journeys will compete with battery vehicles. • Considerations: FCEV trucks will use hydrogen rather than ammonia, so imports by 2030 may need to be cracked back to hydrogen, adding costs and losses.	-	1 million trucks and 3 000 refuelling stations
Cars	Oil (and natural gas or coal)	Many countries already have plans to deploy hydrogen refuelling stations and FCEV cars. • Advantages: Providers of refuelling solutions and vehicles are active and able to scale-up by 2030; hydrogen-based mobility has fairly strong political and industrial support; at scale, hydrogen cars can provide significant demand (50-200 refuelling stations and 100 000 cars could use around 0.02 Mt H_2/yr). • Considerations: Some fuel cell electric vehicles (FCEVs) already on the road displace internal combustion engine vehicles but most FCEV cars today likely displace battery electric vehicles or plug-in hybrids, potentially leading to only minor substitution of natural gas or coal in electricity grids; refuelling infrastructure must be developed in tandem with FCEV sales; demand for FCEVs among drivers is not well tested; availability of different FCEVs is limited; EU companies	~0.0002 Mt H_2	5 million cars and 10 000 refuelling stations

Sector/application	Substituted fuel	Detail	Estimate of current EU demand	To reach 1 Mt H_2 demand
		are not leaders in FCEVs; cars will use hydrogen rather than ammonia, so imports by 2030 may need to be cracked back to hydrogen, adding costs and losses		

Implications of the RED II delegated act on production of renewable transport fuels – share of renewable electricity (requirements)

On 20 May 2022 the European Commission published a draft delegated regulation on the requirements for hydrogen and hydrogen-based fuels to be considered as eligible towards member states targets under the Directive on the on the promotion of the use of energy from renewable sources (RED II). The delegated act concerns the level of proof required to demonstrate that hydrogen is produced from renewable electricity and leads to reduced emissions. Stakeholders have submitted comments on the draft, which will now be finalised before entering into EU law, possibly by the end of 2022.

While the requirements for fuels (referred to in the Directive as renewable fuels of non-biological origin, or RFNBO) apply only to their inclusion in national renewable energy targets, it is widely considered that the requirements will become a default standard for low-emissions hydrogen within the EU.

Notably, the European Commission has proposed that the same standard would apply to imports of hydrogen or hydrogen-based fuels, despite accounting systems in many potential exporter countries being less developed and harder to audit.

Requirements:

- Delivered fuels need to have lifecycle emissions of 3.4 kgCO2(eq.)/kgH_2 or below (including upstream emissions, production, distribution and delivery of the product)
- Input energy must be electricity
- The renewable power plants supplying the electrolyser must:
  - have been built no more than 36 months before the hydrogen production starts
  - have not received any subsidy
  - be in the same electricity bidding zone as the electrolyser, or in a neighbouring one (unless the price of electricity there is cheaper)
- The renewable electricity must:
  - have been generated in the same hour as the hydrogen production
- Exceptions:
  - Any electrolyser connected to a grid with ≥90% renewables (during the year before need not prove the origin of the electricity)
  - If it can be proven that the electricity would have been curtailed otherwise, the age requirement of the renewable plant is waived
  - For their lifetime, electrolysers online by 31 December 2026 can use renewable power generated in the same month, not hour, from plants more than 36 months old that received subsidy

3. How quickly can significant quantities of low-emissions hydrogen and hydrogen-based fuels be imported, and in what configurations?

What could the existing pipeline of projects deliver if it all got built with no delays?

Enough projects are under development globally to export 17.6 Mt H_2/yr million tonnes of low-emissions hydrogen by 2030, based on information from the IEA Hydrogen Projects Database and announced information from project developers.[1] Most of this proposed capacity is in Brazil, followed by Australia, Mauritania, and Argentina. Among Middle East and African countries, which are closer to the EU, the largest proposed projects are in Mauritania, Egypt, Oman, the United Arab Emirates, and Saudi Arabia.

Offtake and importing arrangements are lagging behind the scale of planned exports. Of the 17.6 Mt H_2/yr of proposed exports, projects accounting for 7.9 Mt H_2/yr have named potential or agreed offtakers. A further 3.3 Mt H_2/yr of projects cite export to a specific region. The remaining 6.4 Mt H_2/yr of projects have no published proposed delivery desitination.

There are many fewer import terminal projects announced. Even most projects with a named offtaker do not yet have an identified import terminal or port, including those projects with an agreed offtaker in the development consortium. For imports to be realised this decade, import capacity and hydrogen transport infrastructure (such as ships) will need to be brought online at the same pace as export capacity.

Of the projects with offtake details or intended destinations, 8.4 Mt H_2/yr is marked for export to Europe. This includes an agreement for Fortescue Future Industries (FFI) to export 5 Mt H_2/yr to E.ON by 2030, as well as the HyDeal Ambition project, which is expected to export 0.9 Mt H_2/yr by 2030 from certain parts of Europe to other European countries. If realised, these volumes could satisfy much of the REPowerEU import target.

While most of the proposed capacity does not yet have an announced format (molecule) for exporting hydrogen, most projects that have stated their plans in this regard propose to convert the hydrogen to ammonia and export the ammonia by ship. The capacity associated with proposed exports of liquefied hydrogen, liquid organic hydrogen carriers, or synthetic fuels is very small by comparison.

It is also worth noting that many exporting projects are being planned in the same industrial hubs (often near ports). These include the Peçem Industrial and Port Complex in Brazil and the Suez Canal

1 This includes projects for low-emissions hydrogen and hydrogen-based fuels from fossil fuels with CCUS. For projects planning to export hydrogen-based fuels, the energy content of the proposed molecular carrier has been converted to hydrogen equivalence. The total does not therefore equate directly to the sum of the hydrogen produced by each project before its conversion. A number of export-oriented hydrogen projects have not announced a target operation date, or do not expect to be completed by 2030. They were not included in this analysis. Including these projects would bring the total to 31.8 Mt H_2/yr in development.

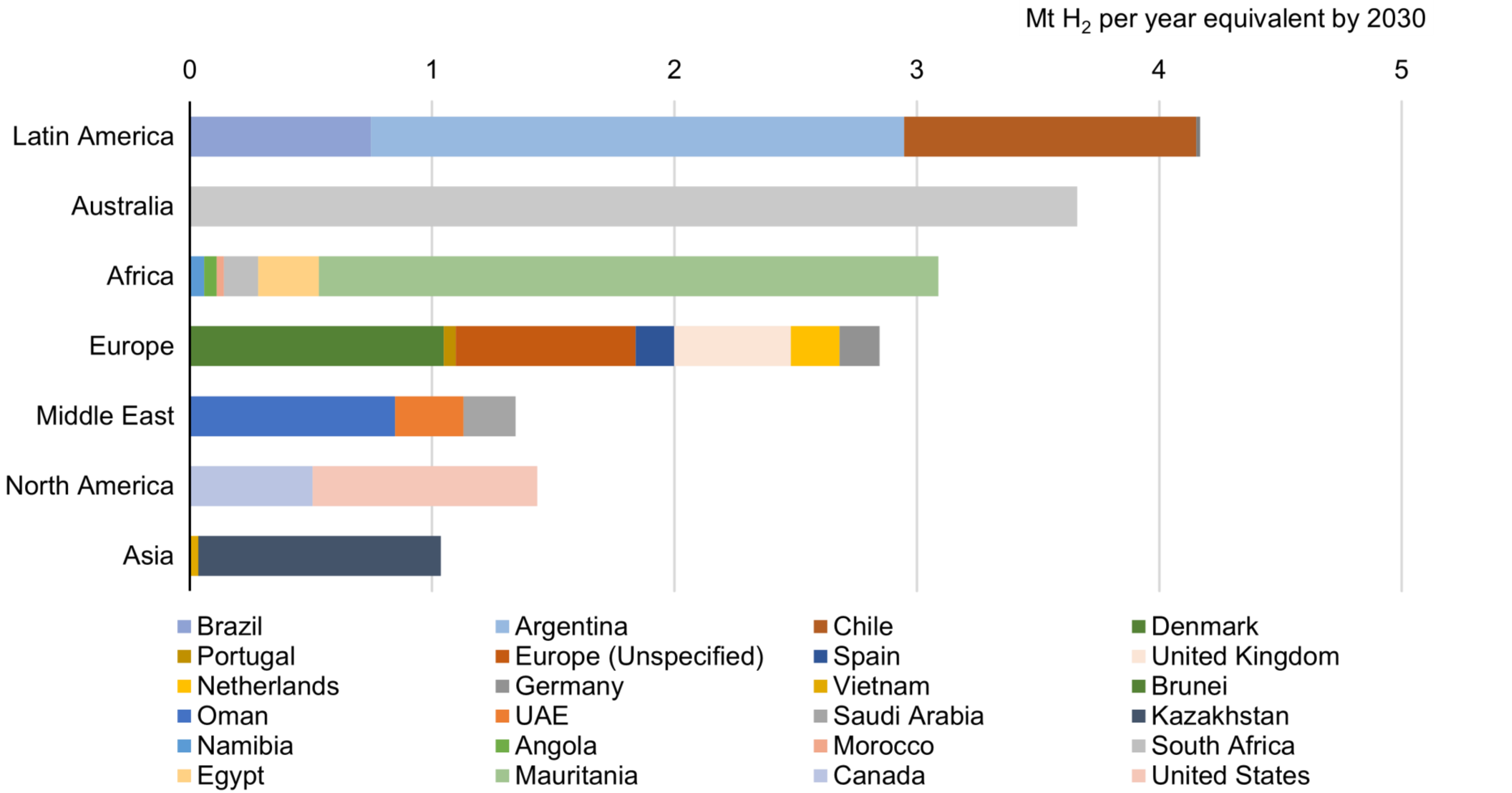
Economic Zone (SCZone) in Egypt. The co-location of renewables development, several hydrogen production projects and export facilities could help lower costs through shared infrastructure and energy integration. It could also help establish the dominance of certain technical standards and molecules for trading.

These estimates of total or Europe-oriented capacity should, however, be taken as an upper bound for several reasons:

- Most projects are at an early stage of development. Only 0.23 Mt H_2/yr of capacity has progressed beyond a final investment decision, and the others will not do so until a grant, contract or other offtake arrangement for the hydrogen is agreed in a way that makes the project risk acceptable. The larger projects will have capital costs (CAPEX) of over USD 1 billion.
- Some of the projects share the same private sector developers, who are likely to stagger their build-out in a way that delays the start-up of some projects.
- Many projects are being developed in places where there is no precedent for bringing a full industrial hydrogen value chain from concept to operation in just eight years or less.
- Many of the high-level findings are shaped by disproportionately large individual projects on the scale of several Mt H_2/yr, so any changes in these individual plans could reshape the hydrogen trade landscape.

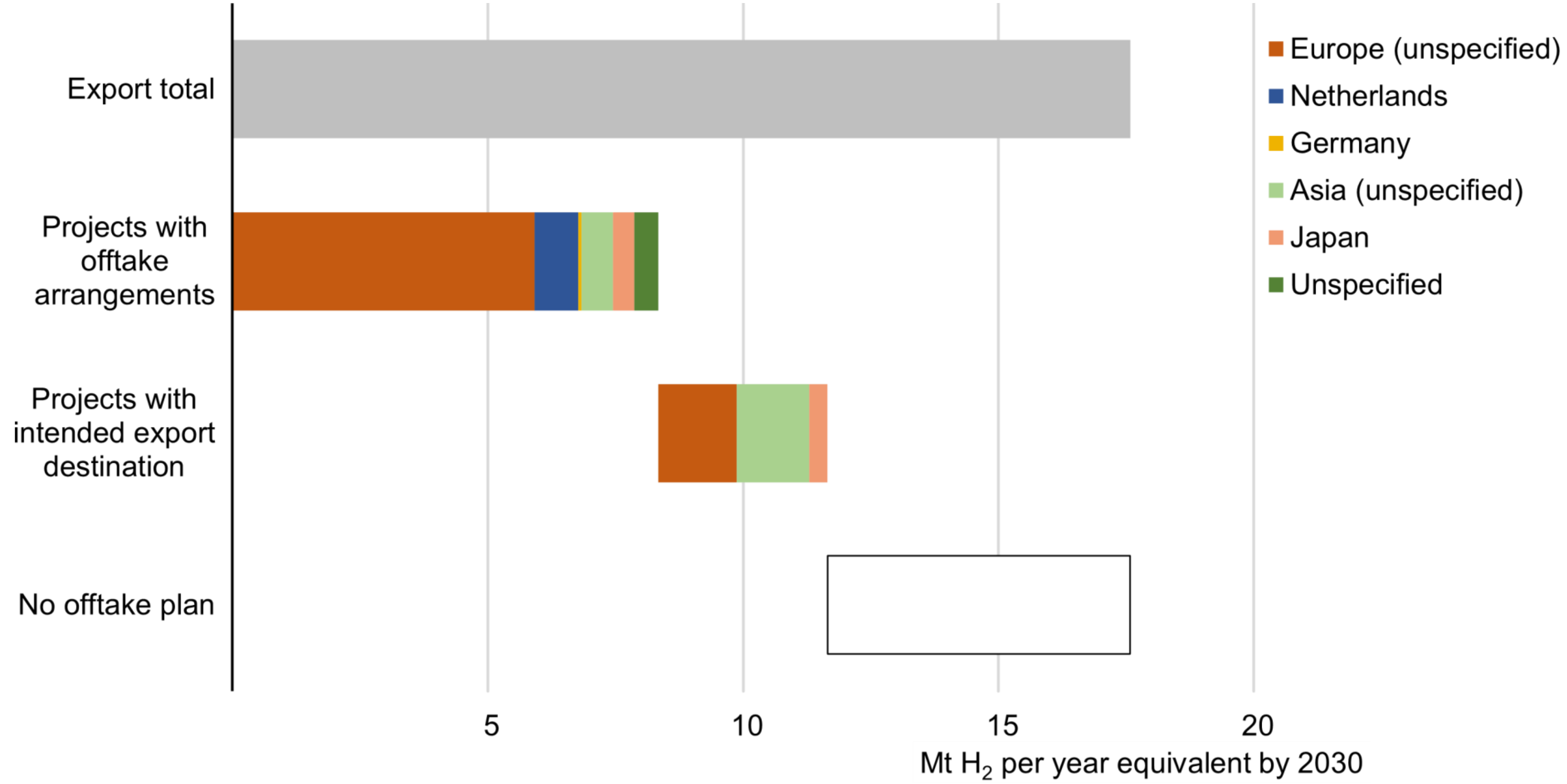
Projects under development globally represent 17.6 million tonnes per year of expected low-emissions hydrogen exports by 2030

Total hydrogen equivalent capacity of proposed international trade projects targeting operation by 2030, by potential exporter country



Most projects with offtake arrangements are bound for Europe, but much of capacity has no offtake plan

Total hydrogen equivalent capacity by 2030 of projects with offtake arrangements or an intended export destination, by importing country



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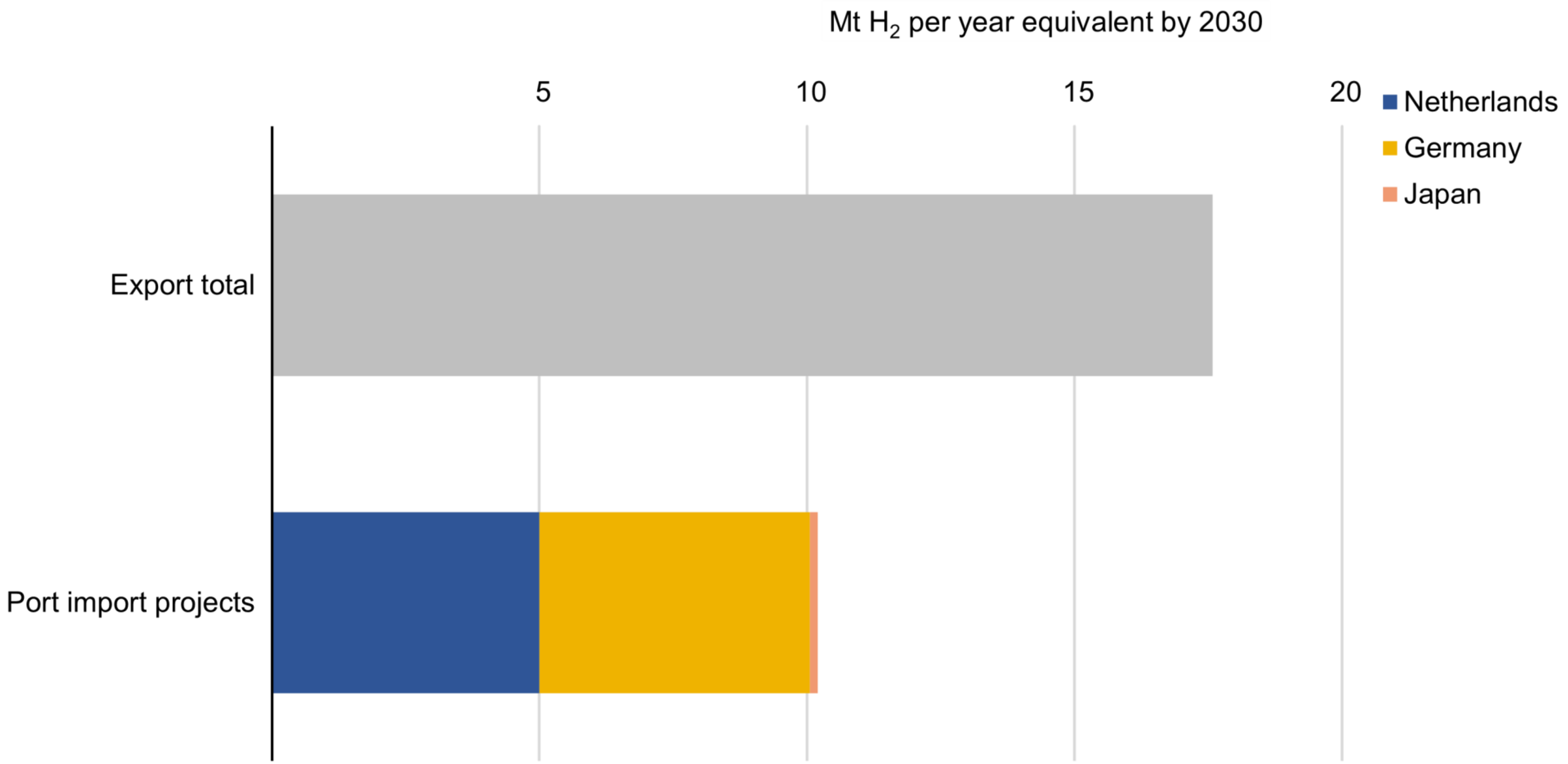
The majority of the proposed capacity does not yet have an identified import terminal, and there are many fewer import terminal projects announced

Total hydrogen equivalent imports proposed by ports for 2030 operation, by country of port



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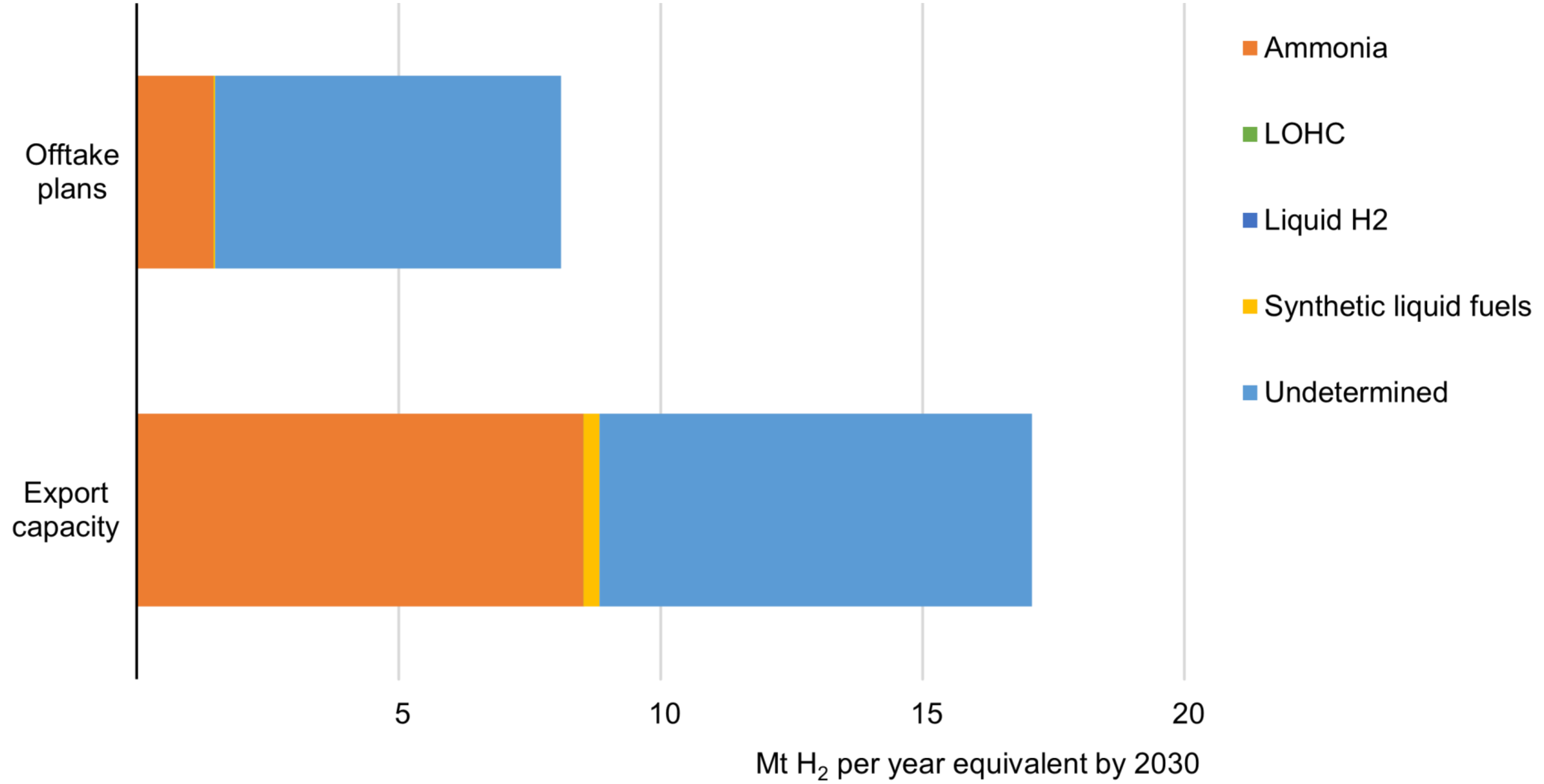
The majority of projects have not chosen a hydrogen carrier, but ammonia dominates among those that have

Hydrogen equivalent capacity of export projects and projects with offtake arrangements, by hydrogen carrier



How advanced is the value chain for international hydrogen trade?

Value chain step	Element	Technical maturity	Commercial status
Primary Energy	Dedicated renewable electricity supply	Mature	Faster deployment constrained by supply chains and permitting. Inflation may prevent continued cost reductions.
	Natural gas supply	Mature	Supply-demand mismatch following Ukraine invasion. High prices in near-to-medium term. Unclear whether some imports of hydrogen from natural gas to EU could contribute to REPowerEU targets.
Transformation to hydrogen and hydrogen-based fuels	Electrolyser manufacturing	Mature	While technology improvements continue, electrolyser factories are expanding rapidly and should be able to cover near-term demand. This expansion will be reliant on contracts for electrolysers being placed, however. There are no factories yet in regions that seek to produce hydrogen for export to the EU. EU factory plans are concentrated in Germany and France. Factory projects outside the EU are dominate by China, where several suppliers are constructing facilities to fulfil contracts for world-scale projects in the 100-300 MW range.
	Hydrogen production via electrolysis	Improving rapidly	Plants up to around 100 MW are well established. Above this level, configurations are still being designed but no bottlenecks are expected. Reaching higher scales is dependent on the development of a service sector that can design, install and maintain facilities in line with emerging safety standards and regulations.
	Hydrogen production from fossil fuels and waste	Improving	Very high levels of CO_2 capture are technically possible but not yet built at scale. The first commercial-scale plants are at the design stage. Technologies for preventing upstream methane emissions exist and must be applied. Effectiveness of CO_2 storage is proven, but requires specific geological conditions available only in certain regions. Business models, policy support and political support are not universally tested untested.
	Ammonia production	Mature	No challenges or bottlenecks foreseen, but developers will need to develop designs that integrate electrolysis and ammonia production to improve overall efficiency.
	Methanol production	Mature	No challenges or bottlenecks foreseen, but production without fossil carbon has not yet been tested. Without non-fossil carbon sources, methanol from low-emissions hydrogen remains a “fossil fuel”. Shipping companies are working hard to address this. Developers will need to develop designs that integrate electrolysis and ammonia production to improve overall efficiency.

Value chain step	Element	Technical maturity	Commercial status
Storage of hydrogen and hydrogen-based fuels	Hydrogen storage	Improving	A potential bottleneck due to the costs of storage to ensure constant supply to consumers. Large-scale, low-cost hydrogen storage today require salt caverns, of which few exist for hydrogen storage today. Salt caverns are not available in all attractive locations for hydrogen supply and use, and tank storage is costly. Although untested for widespread use, linepack in hydrogen pipelines is expected to reduce total storage needs.
	Ammonia storage	Mature	An established part of existing international ammonia trade, but placing ammonia storage closer to the general population (e.g. near distributed power plants) is socially untested.
Transport of hydrogen and hydrogen-based fuels	Hydrogen pipelines	Mature	Dedicated hydrogen pipelines today run between chemical facilities and refineries without problem. However, putting in place pipelines to connect new production with new consumers is a tough investment case and network operators are seeking to get approval for building regulated assets in advance of hydrogen flows materialising. Distribution pipelines near population centres may get held up by safety concerns. The technical and geopolitical considerations relating to investing in new dedicated hydrogen pipelines to import hydrogen across the Mediterranean make it difficult to imagine many such projects by 2030. Blending 5% hydrogen by volume into an existing international pipeline is feasible if the hydrogen production is close to injection points in, for example, Algeria. However, staying below the 5% threshold at any given moment is likely to result in annual averages much lower than 5% by volume (1.6% by energy).
	Liquefied hydrogen ships and compressed hydrogen barges	Immature	The first ships are aiming to be operational in the mid-2020s with a small number afloat by 2030. These pilots will reveal any necessary technical design changes. Barges are proposed for inland waterways but no investments have been made to date.
	Ammonia ships	Mature	An established part of existing international ammonia trade.
	Ammonia cracking	Immature	Never built nor costed at scale but proven in pilot plants.
	Methanol ships	Mature	An established part of existing international methanol trade

Which sectors might be most suited to using imported hydrogen in 2030?

High volume import option for 2030: ammonia by ship

Most attractive use cases:

- Fertiliser plants at ports
- Bunker fuel for shipping
- Power plants at ports
- (Possible) cracking to hydrogen for:
  - Refuelling stations (e.g. trucks at ports)
  - Cogeneration
  - Power plants

Lower volume import option: hydrogen by pipe

Most attractive use cases:

- Blending in the gas grid
- Power plants in Southern Europe
- Fertiliser plants in Southern Europe
- High temperature industrial heat

Lower volume import option: methanol by ship

Most attractive use cases:

- Bunker fuel for shipping
- Chemicals production at ports
- Fertiliser plants in Southern Europe

Low volume import option : synthetic kerosene

Most attractive use cases:

- Aviation bunkering

Low volume import option : synthetic methane (LNG)

Most attractive use cases:

- Power plants
- Industrial heat
- Chemical production
- Buildings heat

Low volume import option: liquefied hydrogen and LOHC

Most attractive use cases:

- Chemical production at ports
- Refuelling stations (e.g. trucks at ports)
- Steelmaking near ports
- Cogeneration at ports
- Power plants and cogeneration near ports
- Industrial heat
- Fertiliser plants

How would shipping affect the emissions intensity of imported hydrogen?

Under the proposed EU delegated act (implementating the RED II Directive), imported hydrogen or hydrogen-based fuels would need to meet the same threshold of 3.4 kg CO_2(eq)/kg H_2 (≈0.54 kg CO_2(eq)/kg NH_3 for ammonia end-uses) across the lifecycle for the delivered fuel as EU-produced fuels. For fuel imported by ship it is expected that some of the cargo (especially boil-off) will be used to power the ship. However, in the 2020s it is more likely that ships carrying hydrogen products will be powered by fossil fuels.

The emissions of using heavy fuel oil to ship ammonia as a hydrogen carrier is shown in the tables below, for various pairs of importing and exporting ports. For long distances, it could account for over 10% of the 3.4kg CO_2/kg H_2, leaving less room for the use of grid electricity in electrolysis or compression, or uses of fossil fuels throughout the chain. In the case of hydrogen produced from natural gas with CCUS, the emissions associated with hydrogen production are around 1.7 kg CO_2(eq)/kg H_2. Upstream methane emissions can vary between 1.4 and 3.9 kg CO_2(eq)/kg H_2, but can be often be avoided at low cost.

Shipping Emissions (kgCO_2/kgH_2)	Brazil (Ceará)	Australia (Queensland)	Oman
Netherlands	0.162	0.458	0.227
Japan	0.436	0.140	0.233
Portugal	0.121	0.413	0.182

Share of 3.4 kg CO2(eq)/kg H2	Brazil (Ceará)	Australia (Queensland)	Oman
Netherlands	4.8%	13.5%	6.7%
Japan	12.8%	4.1%	6.9%
Portugal	3.6%	12.1%	5.4%

4. What policies are still needed to enable investments in low-emissions hydrogen supply for export within or to the EU?

Key policy considerations and relevant EU (and other) policy resources

Project developers throughout the value chain will not take investment decisions in time to reach the necessary scale by 2030 unless some critical pieces of policy support and regulatory clarity are in place. For some of these the next six months are a crucial period for making progress. For others, a tight window could be open for finalising these items in the next two years.

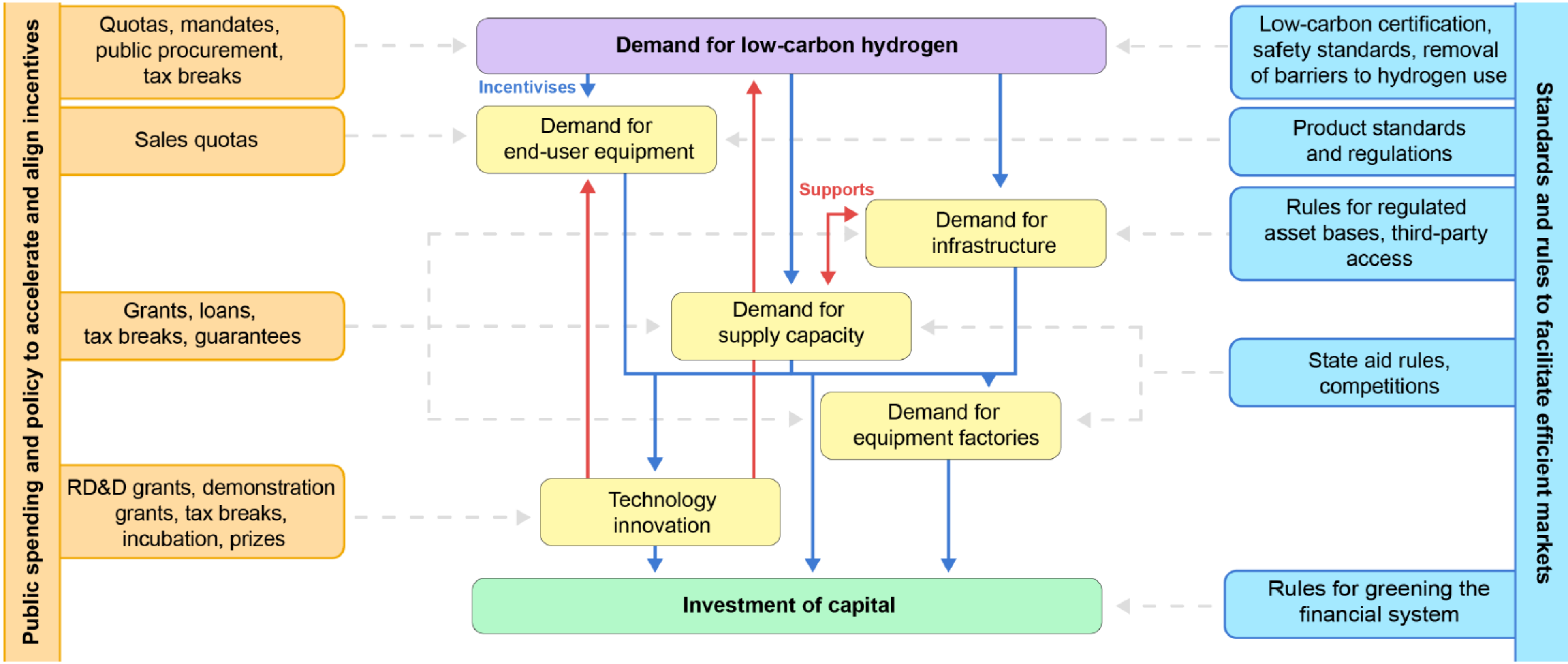
Policy area	Status and information sources
Certification	Requirements are beginning to be proposed for hydrogen to gain the labels that are essential to the development of a product eligible for policy support, regulatory exemptions or premium commercial status. However, different jurisdictions are taking different approaches and it is a matter of some urgency for common systems to evolve, ideally with standardised methods for calculating equivalency between them. • Renewable fuels of non-biological origin: the most advanced EU requirements standards are set out in the RED II delegated act on production of renewable transport fuels – share of renewable electricity (requirements) (see above) and apply to electrolysis hydrogen only. They require 70% lower lifecycle greenhouse gas emissions than an equivalent fossil fuel (or 80% after 1 January 2027 if used for electricity or heat) and places conditions on the renewable electricity input (e.g. 3.4 kg CO_2(eq.)/kg H_2 delivered to a customer). • The EU taxonomy for guiding investments into climate change mitigation takes a different approach. Other forms of electricity are eligible as long as lifecycle emissions at the point of production are 3 kg CO_2(eq.)/kg H_2 or lower. • The US DOE currently defines clean hydrogen as having emissions of 2 kg CO2(eq.)/kg H2 at the point of production (not including upstream emissions, such as fugitive methane, or those associated with transformation and delivery). • CertifHy is a voluntary certification system originally funded by the EC with a threshold of 4.4 kg CO_2(eq.)/kg H_2 (though they are developing tools to certify RFNBO hydrogen) • The Zero Carbon Certification Scheme, an initiative of the Smart Energy Council and Hydrogen Australia, backed by the Government of Victoria and partnering with the German government, will issue Guarantees of Origin based on proof that hydrogen comes from renewable sources, though it is unclear if only renewable electricity will be eligible or also biomass, e.g. via gasification. • TÜV Rheinland Standard H2.21 is an independent certification of Carbon-Neutral Hydrogen, which has a product carbon footprint of zero including upstream emissions and verified offsets. For hydrogen produced from fossil fuels, at least 50% of the CO2 must be captured and stored or any solid carbon must be permanently secured. The IPHE has produced a proposal for a methodology for calculating the emission intensity, and is developing others for end-uses. These proposals could form the basis of an ISO standard, which would take several years to conclude.

Policy area	Status and information sources
Standards	Some international standards for interoperability of hydrogen equipment along the value chain are still needed. 17 ISO standards are under development in working groups and will take several years to be finalised. The Technical Group on Hydrogen Technologies was created in 1990 and has already published 18 standards.
Regulations	• Hydrogen is a non-toxic gas, but its high flame velocity, broad ignition range and low ignition energy make it highly flammable. This is partly mitigated by its high buoyancy and diffusivity, which causes it to dissipate quickly. It has a flame that is not visible to the naked eye and it is colourless and odourless, making it harder for people to detect fires and leaks. Ammonia generally raises more health and safety considerations than hydrogen, and its use would probably need to continue to be restricted to professionally trained operators. It is highly toxic, flammable, corrosive, and escapes from leaks in gaseous form. There are already many decades of experience of using hydrogen and ammonia industrially, including in large dedicated distribution pipelines. Protocols for safe handling at these sites are already in place, and they also exist for hydrogen refuelling infrastructure in site-specific forms. • However, specific regulations remain underdeveloped in some parts of the energy system where hydrogen use is not widespread, including certain transport applications, metering, operator training and equipment performance thresholds.
CAPEX support	• The Important Projects of Common European Interest (IPCEI) lists for hydrogen will allow member states to provide some financial support to businesses beyond the normal limits of state aid rules. The IPCEI list approvals are delayed, with member states' submissions (41 projects in 15 MS) submitted in mid-June 2022. • The EU innovation fund is able to support hydrogen project CAPEX, especially for heavy industry, and the funding for the fund has been doubled by REPowerEU.. • The EIB is able to provide concessional finance to electrolyser manufacturers. • The Connecting Europe Facility can fund cross-border infrastructure within the EU. • Other possible sources: RRF, InvestEU Programme, Life Programme, Interreg, Cohesion Fund, Modernisation Fund and Just Transition Fund. • Other relevant measures: regulated investments by utilities in network infrastructure and capital support to vehicle buyers.
OPEX support and demand creation	The EU Hydrogen Accelerator, outlined as part of REPowerEU, highlights two main options: • An EU-wide systems of carbon contracts for difference. Will need to be aligned across the EU in terms of whether they incentivise the buyers of hydrogen (by covering the difference between their production costs and a benchmark market reference for their product, after carbon pricing) or incentivise demand by allowing the suppliers of hydrogen to offer low prices (by covering the difference between their production costs and a benchmark fossil fuel-based hydrogen price, after carbon pricing). For electricity, the latter approach has been typically used, to limit the number of contracting parties. • A Global European Hydrogen Facility in cooperation with the Member States to create investment security and, hence, business opportunities for European and global renewable hydrogen production, and, at the same time, reliable supply and transparency for European hydrogen usage. The facility could be potentially based on the precedent being established by Germany under H2Global. Other options include:

Policy area	Status and information sources
	• Public procurement for low-emissions goods • Direct support for hydrogen fuel for vehicles • Creating demand by mandating manufacturers to purchase a share of low-emissions hydrogen or derived products, and thereby requiring their consumers to cover the additional operational costs. • Creating demand by pooling voluntary commitments in initiatives like the First Movers Coalition or through certificates for future impacts like the Breakthrough Energy Catalyst.
Offtake and other contracting models	Standardised contracts will help projects to access finance and insurance for hydrogen trade infrastructure, and streamline negotiations. No such contracts have yet been signed for international trade, but LNG experiences point to the necessary elements of contracts that ensure offtake over 10-20 years for the first projects. For these timescales, it is possible that governments could need to take a role in the contracting as guarantors or similar.
Finance cost and risks	• Like solar and wind, electrolysis is a capital-intensive business. For utility-scale solar PV projects the weighted average cost of capital (WACC) can account for 20-50% of the levelised cost of electricity and hydrogen is similar. Helping to bring down the cost of capital by providing revenue support or guarantees to developers with lower credit worthiness can help reduce total costs without direct subsidies. • This is especially important in emerging market and developing economies where the WACC can be 2-5 times higher due to higher systemic market and currency risks. Multilateral banks could play a role in facilitating lower-costs finance where the fundamentals are otherwise strong.
Insurance	Hydrogen value chain investments and individual cargoes will need insurance to be able to access finance and leave port. The insurance industry is at an early stage of developing products for this market and has few precedents on which to base risk estimations. Unless insurance is available at an attractive price, meeting policy targets may require governments to become involved.
WTO trade rules	There are currently no specific rules on international hydrogen trade under the World Trade Organization. This could lead to uncertainty and complication to trade processes regarding issues unique to hydrogen, such as the treatment of hydrogen compared to its derivatives under trade rules. Additionally, process and production method (PPM) standards for hydrogen imports could be challenged as technical barriers to trade if not implemented with a central focus on environmental benefits in mind. Efforts to harmonize PPM requirements across countries must be inclusive to other countries to avoid trade discrimination.
Skills	REPowerEU establishes a need for investments in hydrogen infrastructure across nearly all EU member states, with many large-projects likely needing construction concurrently in the late 2020s. While some companies and countries already have the skills needed to undertake complex engineering projects, operate the assets and provide regulatory clearance (e.g. permits), rapid scale up may require governments to establish training programmes to avoid skills availability becoming a bottleneck.
Permitting	• To speed up permitting procedures for renewable electricity generation, renewable hydrogen production and for infrastructure development, on 18 May 2022 the Commission put forward a legislative proposal on permitting and a related recommendation. Furthermore, under the hydrogen and gas markets decarbonisation package a number of measures have

Policy area	Status and information sources
	been proposed to expedite authorisation procedures for the repurposing of existing natural gas infrastructure for the transport and storage of hydrogen as well as procedures for newly constructed dedicated hydrogen infrastructure. • The European Clean Hydrogen Alliance is working to deliver industry recommendations and best practices to accelerate the authorisation procedures for hydrogen projects.
Coordinated planning of infrastructure and deployment	• The revised TEN-E Regulation, entering into force in June 2022, is a unique instrument for European energy infrastructure planning. It enables a coordinated and timely development of trans-European hydrogen networks, by selecting key infrastructure projects of cross-border relevance based on a robust methodology, in line with EU policy objectives, including hydrogen pipelines, storage facilities, electrolysers and hydrogen terminals, covering as well hydrogen embedded in other chemicals. The stepped-up renewable hydrogen ambition also requires the identification of a limited number of hydrogen import pipelines in that context. • The 2014 Alternative Fuels Infrastructure Directive requires Member States that decide to include hydrogen refuelling points accessible to the public in their national policy frameworks to ensure that, by 31 December 2025, an appropriate number of such points are available, to ensure the circulation of hydrogen-powered motor vehicles, including fuel cell vehicles, within networks determined by those Member States, including, where appropriate, cross-border links. • The 2021 EU "Fit-for-55" package contains 13 initiatives that aim to align EU policy with the European Green Deal and EU climate law. For hydrogen it includes: a target for RFNBOs of 50% in industry's hydrogen consumption and 2.6% in transport fuel demand by 2030; 0.7% synthetic aviation fuels in aviation fuel demand by 2030; 6% lower GHG emissions for ships at EU ports; a zero minimum tax rate for sustainable fuels; and a proposal for a carbon border adjustment mechanism (CBAM)

Demand-side policy interventions are key to amplifying and steering incentives across hydrogen value chains



Source: Global Hydrogen Review 2021.

5. How will the necessary EU infrastructure for importing hydrogen get built and on what terms?

International hydrogen trade: an unusually complex coordination problem for major infrastructure investment

As described earlier in this document, investments in the low-emissions hydrogen value chain require a high level of coordination between players upstream and downstream, and between policies, standads and regulations that need to be finalised.

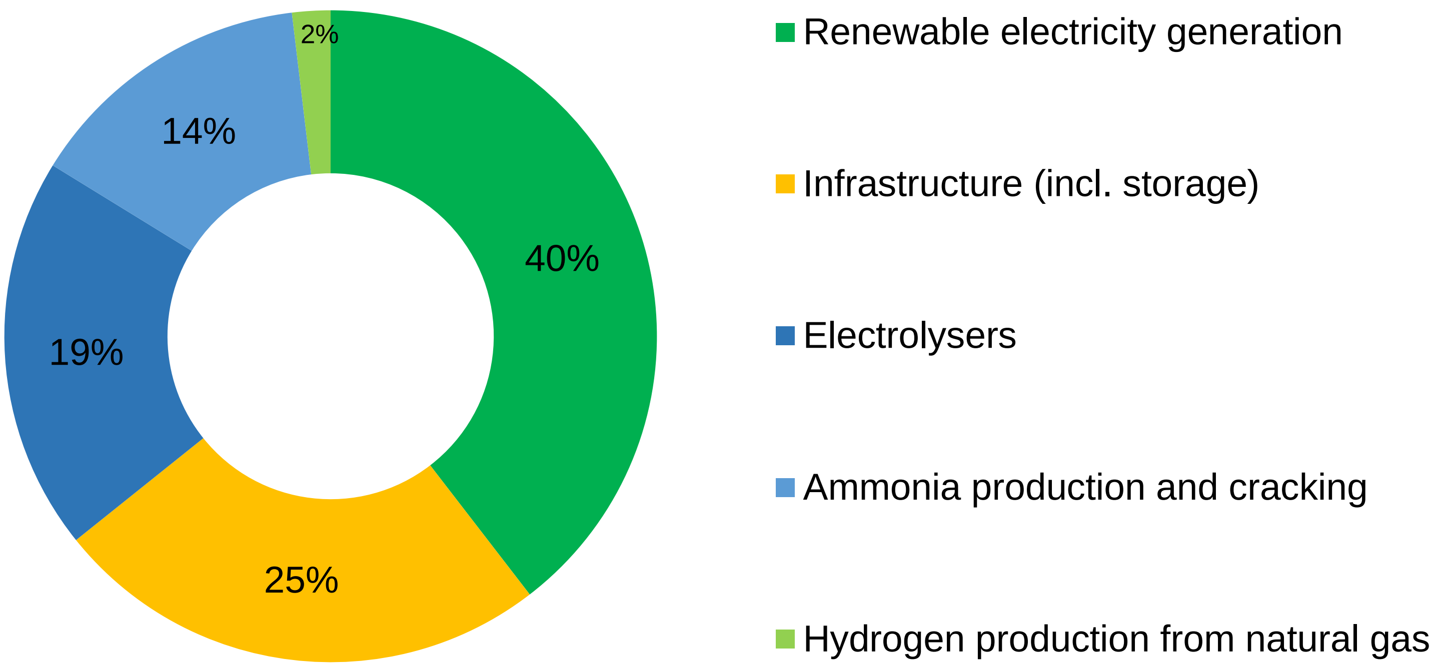
Project developers seeking to finance infrastructure for cross-border hydrogen trade face a range of risks and considerations. Because they are interdependent, they raise the possibility that risks become multiplied with the impacts of raising costs, misaligning value chains or delaying investments.

To illustrate the scale of the challenge, we estimated some of the investment needs to meet the REPowerEU targets.

As a baseline, we estimate capital investment in hydrogen electrolyser projects in 2021 to be around EUR 0.6 billion.

Cost analysis of a possible configuration to meet the target of 10 million tonnes of hydrogen produced in the EU and 10 million tonnes imported

Cost shares of a EUR 600 billion investment plan to secure 20 Mt H_2 for the EU from local and imported supplies



The scope and decisions behind the calculation assumptions for 2030

- Imported hydrogen-based fuels are counted in terms of their equivalence in hydrogen energy content converted to hydrogen mass
- The upper limit for hydrogen imported by pipeline is 0.1 million tonnes per year, equivalent to blending 5% hydrogen by energy content in the Transmed pipeline
- Ships for transporting liquefied hydrogen to the EU are unlikely to be available in this timeframe, as global industrial plans are currently equivalent to ship capacity of 0.2 million tonnes by 2030, earmarked for imports to Japan.
- Hydrogen will be produced mostly from renewable electricity. The cheapest option in exporting countries will involve construction of new solar PV and wind parks that will jointly supply electrolysers in a way that uses local hydrogen storage to optimise electrolyser and ammonia production load factors to minimise costs. To provide the greatest chance of hitting the target, 20% of the exported hydrogen could be produced from local natural gas with CCUS in 2030, projects for which are already being developed. For EU production, up to 20% of the hydrogen will be from plants that are linked to new onshore or offshore wind or solar PV only, i.e. not hybrid renewable projects.
- In line with the expected expansion of electrolyser manufacturing capacity, most projects will be built in the second half of the decade when electrolyser CAPEX has fallen to around of half today's cost. For example, this is projected to reach USD 425 kWel for an electrolyser starting operation in 2029, including all installation costs.
- Hydrogen storage needs to equal around 5% of demand by 2030 to balance supply and demand needs, with geological storage, which is cheaper, becoming gradually available from 2025.
- Pipelines equivalent to around 120 km in the EU and 60 km in exporter countries will be needed for each million tonnes of hydrogen used or produced.
- Interest rates on borrowed capital range from 3% (solar PV plants in the EU) to 8% (natural gas conversion and ammonia production outside the EU) depending on the region and infrastructure type.

Features of a possible solution

Taking the elements above into account, a potential configuration would mostly involve the production of hydrogen in the EU for use as hydrogen, where possible produced close to industrial users or blended into the gas grid where local demand cannot be generated in time. Hydrogen blended into international pipelines would be used by natural gas consumers with minimal upgrades to infrastructure.

Imports would be mostly in the form of ammonia, by ship, and used to the largest extent as ammonia by producers of chemicals (especially fertilisers), shipping fuel, in power plants or for district heat at port locations. While there are many projects for export from Latin America, exporters in the Middle East and Africa would be favoured by cost. If only half of the imported ammonia could be used as ammonia directly (equivalent to around 4.5 MT H_2/yr) then large scale cracking facilities to reconvert ammonia to hydrogen would be needed in the EU, ideally at ports.

What would it cost?

We estimate the total CAPEX of such a solution (to produce 10 Mt H_2 in the EU and deliver 10 Mt H_2 from outside the EU) to be around EUR 0.6 trillion in the period to 2030, or EUR 1.3 trillion if the cost of capital is included and entirely allocated to the pre-2030 period.

Of this CAPEX total:

- 54% would be inside the EU and 46% would be outside the EU (including ships)
- 40% would be for renewable electricity generation plants
- 34% would be for electrolysers and ammonia production plants (roughly equally split)
- 25% would be for port, pipeline, ship and hydrogen storage infrastructure

These costs do not incude investments in end-use sectors – such as transport, power generation or industry – to adapt existing equipment to be able to accept the new hydrogen supplies..