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Are pipelines and ships an 'either or' decision for Europe's hydrogen economy? Planning import lines for hydrogen and derivatives

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Abstract

If estimates and targets are to be believed, roughly 6 to 10 million tonnes of hydrogen will be imported into the EU every year by the end of the decade, requiring very significant infrastructural investment decisions. At times, the policy debate appears to frame shipped deliveries of liquid hydrogen or hydrogen carriers and pipeline deliveries as two sides of the same coin, particularly in the wake of a strong shift away from pipeline gas and towards LNG since the Russian invasion of Ukraine. In this paper we explore the cost, scalability, technological maturity, and project evolution of these two delivery methods. We find that although shipping of hydrogen in carriers could in some scenarios deliver the single cheapest tonne of hydrogen, shipping does not appear to have the scalability to meet any meaningful portion of the EU's needs within the next decade or so. We make the case that Europe should have a two-step approach to infrastructure planning. First leveraging its competitive advantage in pipelines, allowing island and remote nations to innovate and scale shipped delivery options, with experimentation for derivative imports in the EU being used to directly decarbonise those sectors. In a second phase the EU can take advantage of advances in shipping to diversify import options if hydrogen begins to constitute a meaningful share of the energy mix.

Keywords

Hydrogen, energy imports, ammonia, infrastructure, pipelines, shipping

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List of acronyms

- bcm – Billion cubic metre
- CAPEX – Capital expenditure
- CCfD – Carbon contracts for difference
- CH_4 – Methane
- d – Day
- ENTSOG – European network of transmission system operators for gas
- EU – European Union
- EU ETS – European Union emissions trading system
- Gt - Gigatonnes
- H_2 – Hydrogen
- IEA – International Energy Agency
- IPCEI – International projects of common European interest
- IRENA – International Renewable Energy Agency
- JRC – European Union Joint Research Centre
- kg – Kilogram
- km – Kilometre
- LCoE – Levelised cost of electricity
- LCoH – Levelised cost of hydrogen
- LH2 – Liquid hydrogen
- LNG – Liquid natural gas
- LOHC – Liquid organic hydrogen carrier
- MeOH – Methanol
- Mt – Million tonne
- MWh – MegaWatt hour
- NH3 – Ammonia
- OPEX – Operational expenditure
- R&D – Research and development
- SAF – Sustainable Aviation Fuel
- t – Tonne
- TCTF – Temporary crisis and transition framework
- TEN – E – Trans European network for energy
- TRL – Technology readiness level
- TWh – TeraWatt hour
- TYNDP – Ten-year network development plan
- y – Year

Introduction

Since its Hydrogen Strategy of July 2020[1] the EU has been progressively ratcheting up the stakes and ambition of its hydrogen aims. Most notably through the Fit for 55 package[2] of summer 2021 and the REPowerEU Communication[3] of May 2022. At the time of writing, the European Commission is targeting 10 million tonnes (mt) of hydrogen production per year in the bloc by 2030, pairing this with an equivalent level of imports[4]. Broadly speaking, independent estimates[5] envisage a smaller expansion of the sector, closer to 12mt by 2030. Nevertheless, for context, the EU currently consumes ~8mt of hydrogen per year[6], virtually none of which is renewable nor imported – requiring entirely new value chains on both counts.

There are many components required to buildout these value chains, essentially from nothing. In previous analyses, we have looked at production[7,8], international partnerships[9], regulation and support mechanisms[10], amongst other aspects. In this paper we will explore the issue of import infrastructure, focusing on deliveries via ship and via pipeline to try and ascertain whether or not they are an ‘either or’ infrastructure choice. Namely, we attempt to take a closer look at the nuances of different ways hydrogen could be imported into the EU, benchmarking them against a timeline of the sectors evolution. In so doing, we offer some rational as to how high-level infrastructure planning could be key to minimising redundancy and complexity in supply chains, ultimately keeping ambitious targets within reach. We offer reflections on the opportunities and limitations of different options and attempt to look beyond only hydrogen and into the standalone markets[11] for its derivatives to explore the scope for differentiation and growth, leveraging competitive advantages, particularly in the context of global competition.

Transport in the conventional gas sector[12] is characterised by both pipelines and shipped cargoes, with a relatively even split in terms of globally traded volumes, although in Europe the share of pipeline imports has historically been higher[13]. As a gaseous energy vector, it is natural that the dialogue on hydrogen has followed a similar structure, but our analysis finds that it does not necessarily mean that the economics, technical properties, and feasibility match up in the same way. Our analysis includes global references and data as we are exploring an international hydrogen market. Moreover, given it is a new sector, this issue is also one of technological innovation. As a result, the ambitions, competitive advantages, and limitations in other regions will impact important technological aspects such as the learning curves of different technologies.

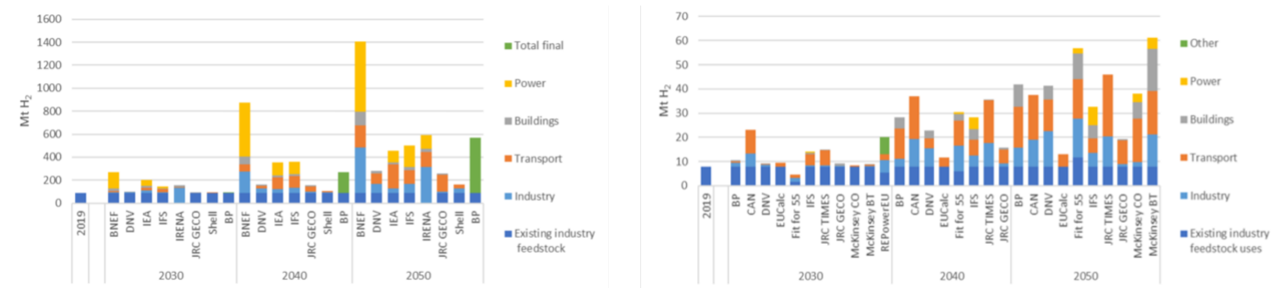
1 European Commission, (2020a). A hydrogen strategy for a climate-neutral Europe, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52020DC0301
2 Kneebone, (2021a). Fit for 55: EU rolls out largest ever legislative package in pursuit of climate goals, https://fsr.eui.eu/fit-for-55-eu-rolls-out-largest-ever-legislative-package-in-pursuit-of-climate-goals/
3 Kneebone, Conti, (2021). A first look at REPowerEU: The European Commission’s plan for energy independence from Russia, https://fsr.eui.eu/first-look-at-repowereu-eu-commission-plan-for-energy-independence-from-russia/
4 This is to include hydrogen demand and its derivatives (i.e. ammonia and E-fuels).
5 Tarvydas, (2022). The role of hydrogen in energy decarbonisation scenarios, https://publications.jrc.ec.europa.eu/repository/handle/JRC131299
6 Burgess, (2021). Feature: Hydrogen targets in EU 2030 climate package will need huge renewable power, https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/electric-power/082321-feature-hydrogen-targets-in-eu-2030-climate-package-will-need-huge-renewable-power
7 Kneebone, Piebalgs, Conti, Jones, (2021). Diversifying risk and maximising synergies in hydrogen technologies: The case of methane pyrolysis, https://fsr.eui.eu/publications/?handle=1814/72003
8 Kneebone, Piebalgs, Jones, (2022). Florence School of Regulation: Cost-effective decarbonisation study 2022, https://cadmus.eui.eu/handle/1814/73658
9 Kneebone, Piebalgs, (2022). Redrawing the EU’s energy relations: getting it right with African renewable hydrogen, https://cadmus.eui.eu/handle/1814/74890
10 Kneebone, (2021b). A first look at the EU Hydrogen and Decarbonised Gas Markets Package, https://fsr.eui.eu/a-first-look-at-the-eu-hydrogen-and-decarbonised-gas-markets-package/
11 I.e. the individual markets for ammonia, methanol, and other hydrogen derivatives in of themselves, rather than just as a hydrogen carrier.
12 Methane gas, commonly referred to as ‘natural gas’.
13 Molnar, (2022). Economics of Gas Transportation by Pipeline and LNG, The Palgrave Handbook of International Energy Economics, https://link.springer.com/chapter/10.1007/978-3-030-86884-0_2

To reach some final conclusions and recommendations on the overall research question, we look to answer the following qualifying questions: (i) what scale of infrastructure is required, and according to what timeline? (ii) How should we conceptualise not only hydrogen transport but also the transportation and standalone markets for its derivatives? (iii) What are the capacities, strengths and weaknesses of pipelines and shipped deliveries? (iv) What are the projects happening at this stage and what can we learn from them? (v) How can Europe's assets best be leveraged in a way that offers a competitive advantage in a global market?

Scale and timelines

An assessment of infrastructural need should first be predicated on the load it must bear, as well as the potential variation and duration in the scale of that service. Below we present the anticipated global hydrogen demand (left) and the EU hydrogen demand (right) along a short (2030), mid-term (2040), and mid to long-term (2050) basis, broken down per several sectors and according to 6 – 11 sources.

Figure 1. Projected global (left) and EU (right) hydrogen demand (JRC, 2022)



These are just scenario analyses, which are subject to different assumptions and choices, particularly in the longer term. There is also plenty of scope for debate on the societal and environmental utility of consuming such large quantities of hydrogen. However, assessing the likelihood of predictions or making value judgements on energy mix are not the subject of this paper. Moreover, the numbers herein are largely taken from a 2022 meta-analysis conducted by the EU's Joint Research Centre (JRC)[14], and as such should represent a balanced and non-ideological view. Nevertheless, the data range across studies considered within the paper indicate the high degree of uncertainty.

It is also noteworthy that the spread between projected demand estimates gets wider withtime. In the EU, the spread is ~20mt in 2030, in 2040 it is ~25mt, and in 2050 it is ~45mt, with a corresponding growth in inconsistency of figures across the different sources making it increasingly difficult to establish a clear trend line. In the context of infrastructure planning this creates difficulties for future proofing assets or building infrastructural capacity out to a timeline.

Broadly speaking, the share of hydrogen in final global energy demand is anticipated to reach 1% by 2030, 5% by 2040, and 10% by 2050. In the table below we provide some indicative figures, based on an average of the JRC aggregated data, as well as some other sources[15], including a breakdown for hydrogen's key derivatives: ammonia, LOHC (methanol (MeOH), in this example), and e-fuels[16], both in the global (left) and EU (right) contexts, where data is available.

14 Tarvydas, (2022). The role of hydrogen in energy decarbonisation scenarios, https://publications.jrc.ec.europa.eu/repository/handle/JRC131299

15 IEA (2021), and Concawe (2021).

16 E-fuels in this context refers to all synthetic fuels produced through a combination of hydrogen and CO_2.

Figure 2. Breakdown of hydrogen, ammonia, LOHC (methanol), and e-fuel demand – current, 2030, 2040, and 2050 for Global & EU in millions of tonnes

	Current*		2030		2040		2050	
Hydrogen	87	8	150	12	330	26	530	40
Ammonia	184**	19	210	~19	220	~19	230	~19
LOHC[17,18] Methanol (MeOH)	85	10	136	18	300[19]	-	500	-
E-fuels	0***	0	7.5	2	40	9.5	100	16.5

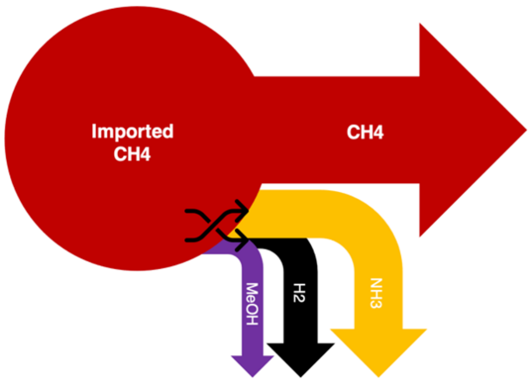
"Current" data is from 2019 to 2022.
***Figures for ammonia demand are from the IEA[20]*
****Figures for e-fuels are based on hydrogen derived synthetic fuels. Historical data and projections based on JRC, 2022 and Concawe, 2021[21]*

Market outlooks

Reflecting on Figure 2 above, it is important to note that these total demand numbers only tell part of the story as regards import infrastructure needs. This is because of the way the value chains are configured differently per each vector depending on whether they are of fossil or renewable origin, as well as the evolution in end uses. However, what all these molecules have in common, whether in fossil or renewable form, is that they are all hydrogen based, often requiring addition of carbon, nitrogen, or other elements to give their final form. As such they each draw on similar energy sources and have a high level of inter-relation across their respective value chains.

For hydrogen, ammonia, and methanol – as well as some of the fuels that e-fuels are looking to replace, the feedstock and often the heat source for production is natural gas, as illustrated below. This is because natural gas is made primarily of carbon and hydrogen (CH4) and as such has many of the components needed to produce these derivative products.

Figure 3. Illustration of energy flows for the majority of existing hydrogen, ammonia, and methanol value chains in Europe (Authors own, 2023)



Note: The flows are only for illustrative purposes and do not reflect proportions of energy, for example.

In order to reduce or eliminate the emissions associated with these fuels, their value chains and the corresponding infrastructure will need to be almost totally rebuilt. In the following analysis we will unpack some principles of how these new lines are beginning to emerge and what can be done to maximise efficiency across vectors, given their interrelationships.

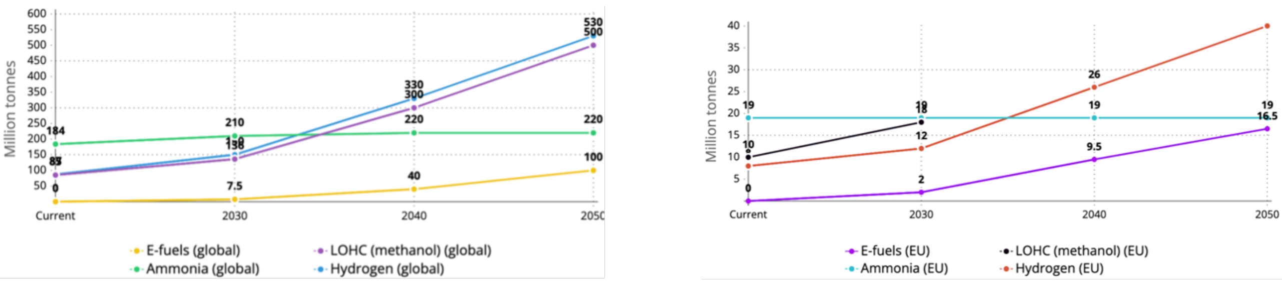
17 Liquid organic hydrogen carriers (LOHC) and in this case we use the example of methanol as one of the most promising LOHCs and as a market with relatively good data, relative to other LOHCs such as toluene.
18 ChemAnalyst (2022) ; IRENA & Methanol Institute (2021) ; Statista 2023 ; MarketResarch.com
19 2040 estimate based on a mid-point calculation re the 2030 and 2050 estimations from Chemanalyst and IRENA respectively.
20 IEA, (2021). Ammonia Technology Roadmap, https://www.iea.org/reports/ammonia-technology-roadmap
21 Concawe, (2021). Transition towards Low Carbon Fuels by 2050: Scenario analysis for the European refining sector, https://www.concawe.eu/wp-content/uploads/Rpt_21-7.pdf

Hydrogen

For example, an increase in overall demand for hydrogen in Europe of 50% from 8mt today to ~12mt in 2030 does not imply a corresponding increase in import capacity. Rather, it requires an increase from 0mt to say 5-10mt as all 8mt of current hydrogen production is located adjacent to demand and not imported. In the existing (fossil) hydrogen value chain, hydrogen is liberated from a hydrocarbon (typically natural gas) and then directly consumed where needed, with producers and consumers favouring to import the hydrocarbon than hydrogen, which is much more challenging to transport. However, in a renewable hydrogen value chain, the energy input is renewable electricity which does not travel long distances so well, requiring the hydrogen to be produced where the cheap and abundant renewable electricity is, rather than where hydrogen demand is[22].

A cursory look at Europe's distribution of existing hydrogen demand against a map of renewable energy resources quickly illustrates that cross-border imports will be required in almost every case, with imports from third countries also likely playing a meaningful role[23]. From this we can see that millions of tonnes of midstream capacity will have to be built within the next 5 or so years. The Figure below visualise the anticipated growth of demand for hydrogen and its derivatives over the coming decades. Note the aggressive and sustained growth after 2030, keeping in mind that the 'current' volumes are all fossil, but by 2030 they must be all renewable – in the EU at least. In this way you can imagine a 'renewable hydrogen line' beginning from virtually 0.

Figure 4. Global (left) and EU (right) hydrogen, ammonia, and e-fuel demand: current, 2030, 2040, 2050 (Authors own, based on JRC, 2022, IEA 2021, Concawe, 2021)



Ammonia

Ammonia (NH3) is a hydrogen derivative and can be produced using renewable hydrogen with the addition of nitrogen. However, currently ammonia in Europe is largely produced with the hydrogen found in methane (CH4) – predominantly using imported (fossil) natural gas as a feedstock and heat source. Unlike hydrogen, there is not an explicit target in the EU for renewable ammonia production by a given date, rather the transition from fossil to renewable origin will be impacted mostly by the cost-effectiveness, availability, and value chains of different feedstocks (namely renewable hydrogen), as well as the cost of energy inputs, and the prevailing EU ETS[24] price.

The EU produces domestically 17mt of its 19mt annual ammonia demand, importing 4mt and exporting 2mt. But again, like hydrogen this is based on imported natural gas as feedstock. As such, if EU consumers or policy makers wish to decarbonise this sector through switching to renewable hydrogen as a feedstock, it will add to the hydrogen demand. Ammonia is anticipated to be a carrier for renewable hydrogen moving forward, suitable for cost-effective long-distance shipping. As such, there are plans for importing large volumes of ammonia with a view to directly cracking it back into hydrogen. Conventional ammonia production causes enormous amounts of emissions, roughly 0.3 gigatonnes (Gt) of CO_2 globally.

22 This rule of thumb for the configuration of value chains is notwithstanding the use of long-distance high voltage direct current (HVDC) cables to move renewable electrons rather than molecules, but this is rather inefficient and uncommon at the moment. There is also a relatively high likelihood that some industrial consumers (e.g. steel or fertilisers) relocate to areas with cheaper energy, including where renewable hydrogen can be produced cheaply. This also undermines the rule of thumb, but nevertheless, will still leave considerable demand in EU – that is the focus of this paper.

23 Up to 50% of final demand by 2030, according to REPowerEU targets.

24 European Union Emissions Trading System (EU ETS).

LOHC (methanol)

Similarly to ammonia, methanol (MeOH) can also be a hydrogen derivative, produced by combining hydrogen with carbon and oxygen. However, at the moment it is also largely produced through steam methane reforming of natural gas. The current market in the EU is roughly 10mt and 85mt globally, potentially growing to 500mt by mid-century. Like ammonia, there is no specific EU target for renewable methanol production or consumption, and as such its uptake will be guided by many of the same drivers as ammonia.

The primary relevance of methanol and other similar LOHCs in a hydrogen context is as a cost-effective carrier for shipping. However, as we see with ammonia, there are significant standalone markets for the fossil incumbent versions of these products in the EU, as well as a potential for renewable hydrogen produced or imported into the EU to be used to produce these products. A similar level of interest in these standalone markets as exhibited in the EU policy space as we have seen for hydrogen could have cross sectoral benefits.

We will explore later in the paper how important it is to understand these derivative products in their respective sectors, and not only as hydrogen carriers. We chose to use methanol as the example LOHC due to the availability of data and the size of the market relative to others, but there are several other promising LOHCs with their own standalone markets, such as Toluene. Conventional methanol production is responsible for roughly 0.165Gt of CO_2 emissions globally.

E-fuels

Finally, e-fuels are likely to remain quite marginal in terms of volumes for the foreseeable future relative to hydrogen, ammonia, and methanol. Predictions on the growth of these vectors (e-kerosene, e-methane, e-diesel, etc) are often guided to a large extent (more so than other vectors) by individual ideology on the future of road transport. As such, there is also a high level of uncertainty in the anticipated total demand volumes. If e-fuels win the race against battery electric vehicles and fuel cell electric vehicles, then there is a potentially enormous market. However, it is unlikely that this is the case in Europe at least, following the decision to phase out the sale of petrol and diesel cars in the bloc[25].

That being said, in Europe there is a level of 'known' demand for these synthetic fuels as sustainable aviation fuel (SAF) targets are being introduced from 2025[26], a share of which will be synthetic[27]. Similarly, in the shipping sector there is a mandate for 2% of fuel to be synthetic by 2030[28]

25 European Parliament, (2022). EU ban on the sale of new petrol and diesel cars from 2035 explained, https://www.europarl.europa.eu/news/en/headlines/economy/20221019STO44572/eu-ban-on-sale-of-new-petrol-and-diesel-cars-from-2035-explained

26 The minimum share of SAF supplied at each EU airport should be 2 % in 2025 and 5 % in 2030, increasing to 20% in 2035, 32 % in 2040, 38 % in 2045, and 63 % in 2050.

27 European Commission, (2021). Proposal for a Regulation of the European Parliament and of the Council on ensuring a level playing field for sustainable air transport, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52021PC0561

28 European Parliament, (2021). Amendments adopted by the European Parliament on 19 October 2022 on the proposal for a regulation of the European Parliament and of the Council on the use of renewable and low-carbon fuels in maritime transport, https://www.europarl.europa.eu/doceo/document/TA-9-2022-0367_EN.html

Transport: Pipelines versus shipping

In the following section we will evaluate how best to meet Europe's hydrogen import needs, considering both pipelines and shipped molecules. Underpinning the conversation on transport are a few basic principles.

I. *Renewable electricity in the EU is scarce and will likely continue to be so until at least 2040*[29]*, this creates opportunity costs in its allocation.*

Conversion of renewable electricity into hydrogen incurs losses in energy[30], with those losses increasing with every subsequent conversion (into ammonia, e-fuels, etc) and reconversion back into electricity or hydrogen. Transport planning should therefore take account of these externalities when considering options, not only cost, scalability, etc[31].

II. *Local production of hydrogen without conversion to a carrier or transmission via long distance pipeline is the cheapest option where the delta in LCOE*[32] *between supply location and demand location is less than ~20€/MWh*[33,34].

In short, a roughly 20€/MWh delta in LCOE is what is typically required to cover the import costs in many scenarios. The principle here is to illustrate that the price and availability of renewable electricity is still the determining factor in a renewable hydrogen economy, more so than the cost of different transmission options even. If there are cheap and abundant renewables close to demand, then this is the more attractive option and efforts should be made to keep these supply chains short and local where it is in complement to the wider integration of renewables. Post 2040 where the EU is potentially no longer in a renewable scarce scenario, there may no longer be a 20€/MWh delta in LCOE with other regions, and as such the need for imports might diminish.

III. *The size of the internationally traded hydrogen market is likely to be much smaller than other international energy markets, and expectations for infrastructural need should reflect that.*

For context, roughly 75% of the oil market is traded internationally and 25% consumed domestically. In the hydrogen sector these figures will likely be roughly inversed, as well as the distance of trades likely shortening and becoming more regionalised[35]. Project planners should not expect that revenues made from trade and transport of hydrogen and its derivatives will be sufficient to fill the shortfall created by the phase out of hydrocarbons.

29 Belmans, Dos Reis, Vingerhoets, (2021). Electrification and sustainable fuels: Competing for wind and sun, https://fsr.eui.eu/publications/?handle=1814/71402

30 As well as emissions embedded in the infrastructure required to carry out these conversions.

31 I.e. minimising the externalities from the production and use of these fuels by avoiding multiple conversions across carriers where it is not warranted. This is also true as concerns the EU's responsibility for the impact its own demand has in third countries.

32 Levelised cost of energy (LCOE).

33 Euros per megawatt hour of electricity.

34 Tarvydas, (2022). The role of hydrogen in energy decarbonisation scenarios, https://publications.jrc.ec.europa.eu/repository/handle/JRC131299

35 IRENA, (2022a). Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Trade Outlook for 2050 and Way Forward, https://www.irena.org/publications/2022/Jul/Global-Hydrogen-Trade-Outlook

Pipelines

Financial cost

The cost dynamics for pipelines are high CAPEX with a near linear relationship between length and cost but relatively low OPEX, increasing only marginally with higher volumes. Pipelines are currently the dominant transport means of choice for the existing hydrogen sector, utilising mostly relatively local networks, supplemented by some road transport with trucks. The US have the longest existing hydrogen network at over 2,600kms, the majority of which is concentrated in the Gulf of Mexico[36]. Industrial north-western European nations Belgium, Germany, France, and the Netherlands operate a combined ~1550kms of pipelines, often in regional industrial clusters, for example around and between the ports of Rotterdam, Antwerp, and Zeebrugge[37].

Estimates for hydrogen delivered via new pipelines place the pipeline CAPEX at roughly 60% of the total transportation cost, followed by the compressor OPEX (23%), compressor CAPEX (12%), and pipe OPEX (6%). According to one study[38] the overall cost is ~4.5 – 10€/MWh H2/1000km, depending on the diameter of the pipe. Other studies put the price closer to 13€/MWh H2/1000km[39]. The key to bringing down the cost of hydrogen pipelines is to cut the pipe CAPEX component as much as possible, this can be done by repurposing existing pipelines that are currently used for natural gas. In this scenario, OPEX becomes the dominant price component, with compressor operation representing 44% of the overall cost and pipeline CAPEX dropping to only 22%, at a total cost that could be as low as ~0.075 – 0.011€/MWh H2/1000km[40], roughly 1/75th the price of a new build. For example, this study[41] estimated the cheapest imported hydrogen that Germany can access is via pipeline from Denmark, Ukraine, or North Africa[42].

Advantages

One key advantage of a pipeline is that it can transport massive volumes very consistently. This is important for many end-uses, particularly those foreseen to be the early off-takers such as plastic recycling facilities or steel plants, both of which need a constant flow of consistent quality/purity hydrogen.

Crucially, pipelines are also how fossil hydrogen is currently delivered in the majority of cases. These conditions could also be achieved by using storage facilities to buffer against deliveries in shipments, however this requires additional infrastructure and an additional step in the value chain. Moreover, given the level of uncertainty of demand for renewable hydrogen from 2030 to 2050 and the importance of ongoing competition with other energy vectors, minimising the complexity of value chains and therefore the risk of stranding assets, repurposed pipelines are extremely attractive.

As it is a fixed piece of infrastructure, pipelines also create a strong incentive to maintain trade between two parties – at least following a commercial 'realpolitik'. This configuration can have drawbacks which we will discuss in the next section, but advantages include a higher likelihood for establishing and securing long-term and consistent trade flows relative to shipping where delivery can always change. Potential exporting countries in the EU's neighbourhood include Norway, Morocco, Tunisia, Ukraine, all of which have existing pipeline connections to the EU and with whom therefore

36 NREL, (2018). Regional Supply of Hydrogen, https://www.nrel.gov/docs/fy19osti/71566.pdf

37 Statista, (2016). Length of hydrogen pipelines worldwide by country, https://www.statista.com/statistics/1147797/hydrogen-pipeline-length-by-country/

38 Gas for Climate, (2022). Facilitating hydrogen imports from non-EU countries, https://gasforclimate2050.eu/wp-content/uploads/2022/10/2022_Facilitating_hydrogen_imports_from_non-EU_countries.pdf

39 Tarvydas, (2022). The role of hydrogen in energy decarbonisation scenarios, https://publications.jrc.ec.europa.eu/repository/handle/JRC131299

40 Gas for Climate, (2022). Facilitating hydrogen imports from non-EU countries, https://gasforclimate2050.eu/wp-content/uploads/2022/10/2022_Facilitating_hydrogen_imports_from_non-EU_countries.pdf

41 Hampp, Düren, Brown, (2023). Import options for chemical energy carriers from renewable sources to Germany, https://arxiv.org/pdf/2107.01092.pdf

42 Transmission cost of €1.0 - €1.3 in 2050.

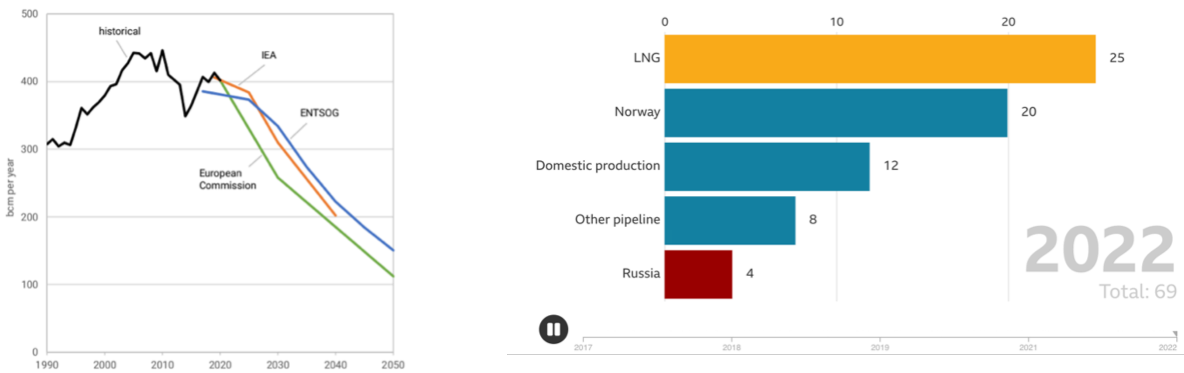
the EU could be a more attractive destination for exports relative to other regions where new delivery means would need to be established.

Furthermore, as the EU looks to reduce its consumption of natural gas in the coming years, hydrogen potentially presents certain gas exporting and transit countries with a new commercial opportunity, as well as the chance to extend the useful life of transmission assets. In particular this could be interesting for Tunisia, Morocco, and Ukraine who have existing pipeline connections to the EU and could either generate revenue as transit regions for hydrogen from further afield and/or as exporters themselves. The EU has long been collaborating with its neighbourhood regions on these aims[43].

Ultimately however, the main benefit of a pipeline is that it can deliver massive amounts of energy with little marginal cost for increasing volumes, providing the capacity to ramp up over time. The lower volumetric energy density of hydrogen relative to natural gas (~67% lower) is mitigated by a molecular weight that is roughly nine times less, meaning that a repurposed natural gas pipeline can deliver 80-98% of the energy in hydrogen that it previously supplied in natural gas. The EU would potentially need only 5 or so large diameter pipelines to cover its hydrogen import needs[44] and with a network of around 200,000km there is plenty of capacity to expand into as the need evolves.

The implication of repurposing natural gas pipelines is that those lines are no longer needed for natural gas transmission. According to the EU's own modelling, natural gas consumption in the bloc needs to decline by 36% by 2030 to meet climate targets[45]. Correspondingly, many Member States are investing heavily in LNG import capacity as an alternative to pipeline deliveries, largely due to heavily reduced supplies of Russian pipeline gas, or subsequent fears about single supplier dependencies. In fact, by the end of 2022, LNG deliveries had become the predominant single source of gas in Europe[46].

Figure 5. Scenarios for EU-27 fossil gas consumption (GEM, 2021) (left) and Monthly gas supply to EU-27 plus UK (mcm) by origin (OIES via BBC, 2023)



It could be reasoned therefore that it is increasingly likely that certain natural gas transmission lines will become stranded more quickly than forecast, potentially increasing the attractiveness of switching those to hydrogen. Even for pipelines that have sustained natural gas demand, a growth in LNG import capacity potentially creates flexibility to switch use of the pipelines[47].

43 European Commission, (2020). A hydrogen strategy for a climate-neutral Europe, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52020DC0301

44 IRENA, (2022b). Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Technology Review of Hydrogen Carriers, https://www.irena.org/publications/2022/Apr/Global-hydrogen-trade-Part-II

45 European Commission, (2020b). Stepping up Europe's 2030 climate ambition Investing in a climate-neutral future for the benefit of our people, https://eur-lex.europa.eu/legal-content/en/ALL/?uri=CELEX:52020DC0562

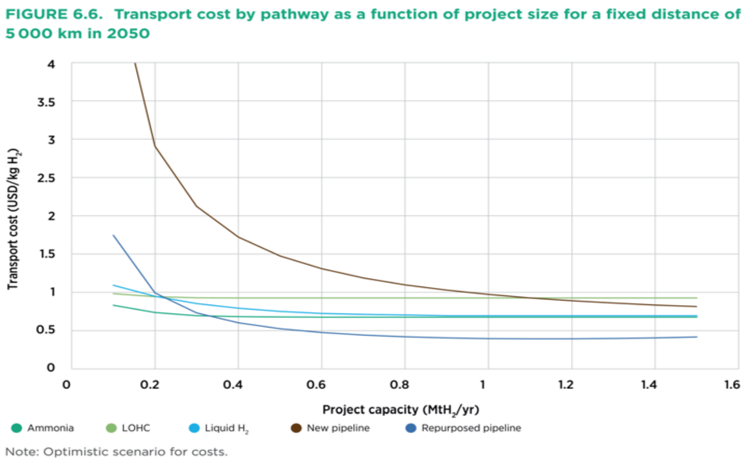
46 https://www.bbc.com/news/58888451

47 This characterisation of the relationship between declining natural gas volumes in certain transmission lines and increasing hydrogen transmission demand overall is purely conceptually, and certainly warrants a detailed analysis looking at specific transport routes. This analysis is also needed regards the capacity of ports to receive growing volumes of LNG and alongside new volumes of clean molecules.

Disadvantages

Arguably the biggest issue with pipelines is the impact of the cost dynamics on infrastructural forward planning. Ultimately, the high upfront costs commit investors to sourcing and distributing enormous volumes of a product that as of yet, does not really have an assured market.

Figure 6. Transport cost by pathway as a function of project size for a fixed distance of 5,000km in 2050, (IRENA, 2022b)



For the scenario illustrated in the Figure above, only at a project size of 1.4 million tonnes of hydrogen per year (MtH2/y) is a new build pipeline cost competitive with LOHCs. Even at this volume it remains uncompetitive with ammonia, liquid hydrogen, and repurposed pipelines. Moreover, with a total market size of ~12mt anticipated for 2030, these volumes may need to be concentrated along just five or so trunklines to make the transmission cost-effective. There is a risk that this requires decisions to be taken on trading partners already at a very early stage, potentially limiting options before the global production market has really had chance to compete on delivered cost. On the offtake side, highly centralising the transmission infrastructure might have a big impact on what end uses become practical and cost-effective, for example limiting the attractiveness of distributed and off-grid demand (road transport, utility vehicles, rural residential applications, etc). Depending on perspective this could arguably also be considered an advantage to avoid the application of renewable hydrogen in applications with weak decarbonisation credentials, but it certainly implies value judgements.

That being said, the 5,000km distance cited in the Figure is a relatively long distance for transmission considering that hydrogen is much more likely to be regionally traded than globally traded, at least in the short to mid-term[48]. A more regional trade structure could potentially imply more fragmented delivery lines. Furthermore, projections for the cost reduction of liquid hydrogen and LOHC's between now and 2050 are highly speculative. Other studies anticipate hydrogen pipelines of all kinds to be the most competitive delivery option for distances under ~3,000km[49], comfortably long enough to connect demand centres in Western Europe with cheap production in North Africa, Southern Europe, the North Sea, or Ukraine.[50] See below for an illustration.

48 IRENA, (2022a). Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Trade Outlook for 2050 and Way Forward, https://www.irena.org/publications/2022/Jul/Global-Hydrogen-Trade-Outlook

49 Or even up to 18,000km (essentially any two locations connected by land), if repurposed.

50 Rabat, Morocco to Dortmund, Germany is roughly 2,250KM for example, creating considerable margin for deviations in the route of the pipeline.

Figure 7. Illustration of hydrogen delivery costs for a simple (point to point) transport route for 1mt H2 and a low electricity cost scenario. (JRC, 2022)

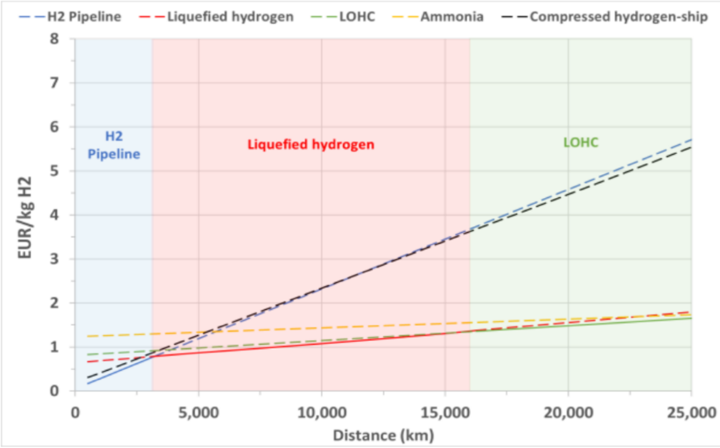


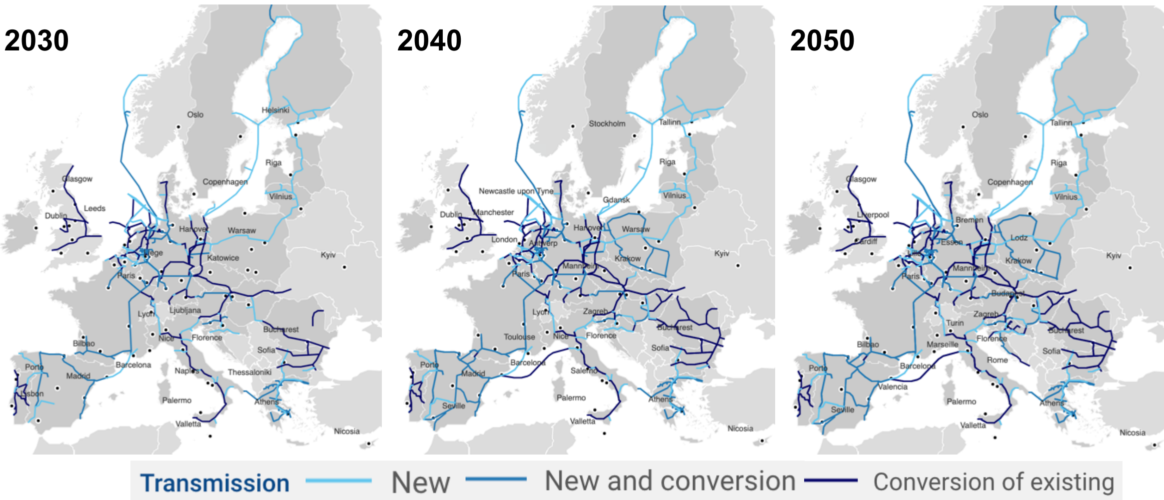
Figure 2 Hydrogen delivery costs for a simple (point to point) transport route, for 1 Mt H_2 and low electricity cost scenario.

Another issue with pipelines is the management and maintenance aspect. Firstly, the corrosive properties of hydrogen are expected to fatigue the pipes and components very quickly, relative to methane gas. There also is not yet a clear consensus on how best to execute practical aspects for long distance transmission like injection[51], or to avoid leakage and the associated safety and climate risks[52]. This adds to the gamble associated with committing to such a centralised infrastructure.

State of play

The Figure below illustrates the hydrogen transmission projects already announced at the time of writing, as collected by ENTSOG under their quarterly updated 'H2 Infrastructure Map'[53,54].

Figure 8. Maps of planned hydrogen transmission infrastructure in Europe and neighbourhood region based on projects submitted to the 'H2 Infrastructure Map' platform as of 11.04.2023 covering three time frames (2030, 2040, 2050) (ENTSOG, 2023)



51 Liu, et al., (2021). Analysis of Hydrogen Gas Injection at Various Compositions in an Existing Natural Gas Pipeline, https://www.frontiersin.org/articles/10.3389/fenrg.2021.685079/full

52 Ocko, Hamburg, (2022). Climate consequences of hydrogen emissions, https://acp.copernicus.org/articles/22/9349/2022/

53 ENTSOG, GIE, Eurogas, CEDEC, GD4S, GEODE, (2023). Hydrogen Infrastructure Map, https://www.h2inframap.eu/#keys

54 There will be some projects planned that are not submitted to the infrastructure map, but this is currently the most comprehensive database for consolidated project data in the EU.

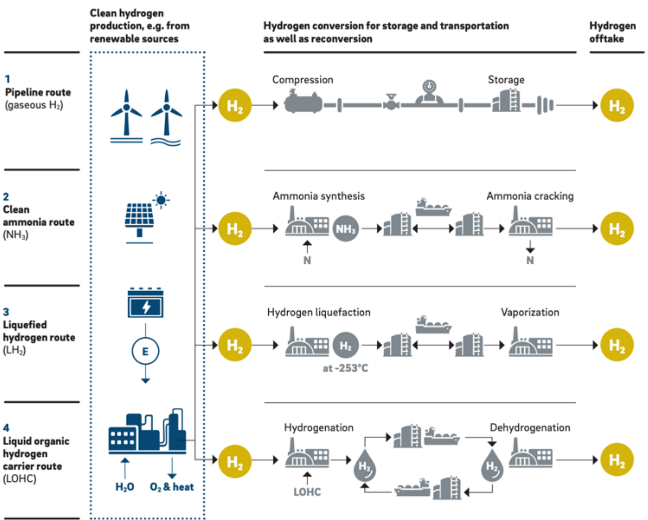
Although there is evolution in the infrastructure from 2030 through 2040 and 2050, particularly in eastern and south-eastern Europe, the majority of the main 'corridors'[55] are established by 2030. Calculating[56] the anticipated capacities of the corridors that specify transmission data (which is not all), gives a transmission capacity of roughly 30mt/H2/y by 2030, more than enough to cover the projected ~12mt forecasted by that date. It is likely however that some of these projects will not be commissioned in the end, or not within the time frame envisaged. Conversely, the maps for 2040 and 2050 will become more developed as we get closer to those dates, keeping in mind that this is a consolidation of planned projects, not a forecast.

Shipping hydrogen and its derivatives

Shipping is fundamentally a more technically complex process than pipeline deliveries. Here is a quick outline of the value chain to give context to the components that contribute to the final cost and the advantages and disadvantages.

1. Pipeline from the hydrogen production site to the export terminal
2. Conversion of gaseous hydrogen into the shipping medium
3. Storage at the export terminal
4. Shipping
5. Storage at the import terminal
6. Reconversion to gaseous hydrogen
7. Pipeline to the demand location

Figure 9. Leading carriers for large-scale hydrogen transportation, (Roland Berger, 2021)



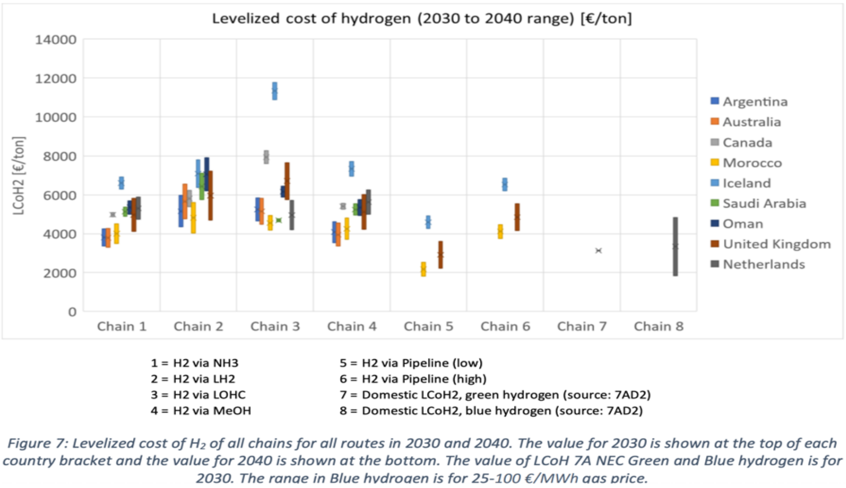
55 European Commission, (2022). REPowerEU Plan, https://eur-lex.europa.eu/resource.html?uri=cellar:fc930f14-d7ae-11ec-a95f-01aa75ed71a1.0001.02/DOC_1&format=PDF

56 1 GWh = ~30t H2. Eastern corridor = 144GWh/d; Nordic/Baltic Corridor = 740GWh/d; North Sea corridor = 1274GWh/d; South Central corridor = 448GWh/d; Iberian corridor = 200GWh/d; South-Eastern corridor = 76.8GWh/d. Total = 2,882GWh/d * 30 = 86,484t H2/d * 365 = 31.6Mt/y.

Financial cost

Broadly speaking, it is not clear at this point what form of hydrogen carrier is the most cost competitive. Recent studies such as this one from 'HyDelta'[57] found that there are a myriad of factors impacting the delivered cost which vary considerably from case to case. Figure 10 below illustrates the extent of the spread for deliveries to the Netherlands originating in different prospective suppliers utilising various means, including pipelines.

Figure 10. Levelised cost of hydrogen of all chains for all routes in 2030 and 2040. (van der Meulen, et al., 2022)[58]



The cost range for carriers is roughly as follows;

- Ammonia (NH3): 4.1 – 6.5€/kg (2030), 3.5 – 6.2€/kg (2040)
- Liquid hydrogen (LH2): 5.6 – 8.0€/kg (2030), 4.0 – 6.1€/kg (2040)
- Liquid organic hydrogen carrier (LOHC): 4.8 – 11.7€/kg (2030), 4.1 – 10.8€/kg (2040)
- Methanol (MeOH): 4.4 – 7.7€/kg (2030), 3.5 – 7.0€/kg (2040)

Regardless of origin and carrier, LCOE remains the dominant cost driver, accounting for the major share of the delivered cost in each case. Beyond LCOE, there are differences in cost structure across the carriers, for example LH2 requires more energy than the rest for liquefaction which adds energy cost, but it does not require the conversion and reconversion infrastructure of the other carriers. As regards the physical transmission step, NH3 and MeOH are better transportation fuels, and as such gain a slight favour in the longer shipping distances in this area. From 2030 to 2040 the gaps between the carriers tighten, with LH2 becoming competitive with the more established practices of shipping MeOH and NH3. This is largely due to anticipated advances in the cost efficiency of hydrogen liquefaction and cargo ships, as well as cheaper and more abundant renewable energy mitigating the higher energy requirements for LH2. The scope for development in LH2 is best exemplified by the larger range bars (i.e. 2030 – 2040) for virtually every supplier.

As regards the comparison to pipelines, the study gives figures for pipelines where possible, i.e. from Morocco, the UK, and Iceland, although the likelihood of connecting the Netherlands to Iceland via pipeline is extremely low. Even in the more pessimistic 'Chain 6' scenario, pipelines are typically the most competitive choice (4.2 – 7.0€/kg (2030), 3.8 – 6.1€/kg (2040)), discounting Iceland makes an even clearer case. Estimations from some of the other studies mentioned in the previous section cite more generic estimates of <1€/kg[59] for distances under ~2,000km with a volume of >1mt/y and indicate a general consensus towards pipelines, especially if they are repurposed from natural gas.

57 van der Meulen, et al., (2022). Cost analysis and comparison of different hydrogen carrier import chains and expected cost development, https://zenodo.org/record/6514173#.Y9qOW-zMLIx

58 Note: The value for 2030 is shown at the top of each country bracket and the value for 2040 is shown is shown at the bottom. The value of LCoH 7A NEC Green and Blue hydrogen is for 2030. The range in Blue hydrogen 25-100€/MWh gas price.

59 Transmission cost, not delivered price.

Similar to pipelines, there are hopes that LNG terminals could be repurposed for deliveries of hydrogen carriers, helping to reduce the final cost. However, unlike pipelines where the conversion process is quite clear and relatively well understood, there are no current examples of LNG terminals that have been repurposed to LH2, NH3, or LOHC. In the most optimistic scenario, early research suggests that it could be possible to repurpose terminals if their original design factors in this subsequent conversion, i.e. in the choice of metals used in storage tanks, the proximity and connection to industrial clusters, and so on. In favourable circumstances, roughly 50% of the initial investment cost for the LNG terminal could be recovered in conversion to LH2, assuming that a cross compatible tank material was used[60,61]. The remainder of the infrastructural CAPEX would not be cross compatible, and as such would need to be entirely replaced.

For ammonia there is a slightly higher level of cross compatibility, due largely to closer thermal and pressure tolerances to LNG. In the case of NH3 it may also be possible to modify the storage tank post-hoc, which gives additional planning flexibility versus LH2. On the other hand, additional infrastructure to crack the NH3 is required for these imports, necessitating additional site space relative to LNG and LH2, not to mention access to vast amounts of additional heat[62].

Considerable uncertainty remains in the scope of repurposing these facilities, it is too early to say with certainty exactly how the economics and technical aspects would stack up in practice and at scale. BioLNG is a much more feasible application for transitioning these facilities, but the EU does not plan to import such large volumes of liquid biomethane[63]. LOHCs are also generally much more compatible with existing infrastructure than LH2, this is broadly for the same reasons as NH3, i.e. the thermal and pressure requirements, as well as existing technical experience for handling these products. However, they also require additional investment to extract the hydrogen, this can amount to 30-40% of the delivered cost[64].

Advantages

Arguably the main advantage of ships over pipes is that deliveries can come from anywhere, offering flexibility and theoretically avoiding dependency on a given supplier. This is valuable from a security of supply perspective, but also in terms of establishing a liquid market, if indeed that is the objective.

After the natural gas crisis of 2022/23 where deliveries of pipeline gas from Russia were quickly and dramatically curtailed[65], the EU and its Member States have moved quickly to increase capacity to receive shipped deliveries of natural gas[66]. As such, there is a clear political momentum towards this form of infrastructure for energy deliveries in general moving forward, particularly amongst the major importers such as Germany. The vulnerability of pipelines to political leverage is not just evident in the Russian case but also in the Mediterranean, where a breakdown in political relations between Spain, Morocco, and Algeria has led to the disconnection of flows of Algerian gas into Spain via Morocco[67]. In this example, Spain this year began re-exporting its LNG gas imports to Morocco via pipeline, highlighting the importance of shipped deliveries.

60 Reimer, Schreiner, Wachsmuth, (2022). Conversion of LNG Terminals for Liquid Hydrogen or Ammonia Analysis of Technical Feasibility under Economic Considerations, https://www.isi.fraunhofer.de/content/dam/isi/dokumente/cce/2022/Report_Conversion_of_LNG_Terminals_for_Liquid_Hydrogen_or_Ammonia.pdf

61 Note that an LH2 compatible tank would be more expensive and likely lower capacity than a standard LNG tank.

62 In the best-case scenario this could be waste heat from adjacent industry, but typically by-product heat is already reutilised within industrial processes. In the worst case, it would need to be energy from the shipment itself.

63 Reimer, Schreiner, Wachsmuth, (2022). Conversion of LNG Terminals for Liquid Hydrogen or Ammonia Analysis of Technical Feasibility under Economic Considerations, https://www.isi.fraunhofer.de/content/dam/isi/dokumente/cce/2022/Report_Conversion_of_LNG_Terminals_for_Liquid_Hydrogen_or_Ammonia.pdf

64 IRENA, (2022b). Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Technology Review of Hydrogen Carriers, https://www.irena.org/publications/2022/Apr/Global-hydrogen-trade-Part-II

65 Kneebone, (2022). A first look at 'Save gas for a safe winter': The EU's fast-tracked proposal for protecting against a disconnection from Russian gas, https://fsr.eui.eu/a-first-look-at-save-gas-for-a-safe-winter-the-eus-fast-tracked-proposal-for-protecting-against-a-disconnection-from-russian-gas/

66 Florence School of Regulation, (2023). Security of Supply: Gas, https://fsr.eui.eu/security-of-supply-gas/

67 Baratti, Elliot, (2022). Spain begins gas re-exports to Morocco via GME pipeline: Enagas, https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/062922-spain-begins-gas-re-exports-to-morocco-via-gme-pipeline-enagas

The second key advantage of this flexibility is potentially an economic one. As alluded to previously, the race for suppliers looking to trade in the global hydrogen market is far from run, and there remains considerable speculation on where the cheapest and most abundant hydrogen will come from. Investing in import terminals creates the opportunity to react quickly to market developments and access the cheapest suppliers. The economics appear to slightly favour pipelines now, but the data is not absolute, and the margin for error is certainly large enough to open the possibility for shipped deliveries to be the most cost effective.

This is particularly interesting as regards the importance of technologies with potentially fast learning curves such as liquefaction, where faster than anticipated cost reductions could allow to leverage very cheap LCOE in faraway locations. In a similar vein, the EU and several Member States have recently agreed new LNG contracts[68], often with a view to switching to deliveries of renewable hydrogen and other clean molecules when the conditions are right. This is a political and trade issue, but arguably also an economic one, as without converting assets to import some form of 'clean molecules', investors may struggle to amortise new LNG terminals before the EU phases out natural gas. LOHC's can have a role here, as they have a high level of compatibility with existing infrastructure[69].

It is unclear whether there will be a sort of 'spot market' for hydrogen in the future, early indications suggest probably not, at least for quite some time. Nevertheless, if such a market did emerge, shipping molecules would probably be the favourable transport choice in this case, rather than the typically much longer-term contracts agreed with pipeline suppliers.

Disadvantages

Although in some ways an advantage of shipped deliveries, the diversity of options amongst carriers is also arguably one of the main weaknesses from an infrastructure planning perspective. As discussed in the previous section, the value chains of each liquid carrier are complex relative to pipelines, but amongst each other the liquid carriers have a low level of cross compatibility. For example, the infrastructure required for reconverting methanol to hydrogen is not the same as the infrastructure required for reconverting ammonia to hydrogen. Given that there is little clarity on the most competitive shipped carrier, there is a juxtaposition of priorities in commercialising these derivatives for hydrogen deliveries.

Firstly, we know that scale is key to reducing marginal cost, which favours a technology choice or at least preferencing amongst carriers. However, as a nascent sector with fast and highly variable learning curves[70], technology preferencing at this stage has a high risk of creating stranded assets. For example, if you had to pick just one carrier based on currently available data, ammonia looks to be generally the most competitive option for shipped deliveries across the widest range of scenarios. This is reflected in the carrier choice of many of the major international partnerships being signed now[71]. However, there is virtually no cross compatibility in infrastructure between ammonia and liquid hydrogen, the carrier with the fastest anticipated learning curve[72]. If liquid hydrogen technology emerges as the most competitive, the ammonia cracking infrastructure could become stranded. This scenario puts policy makers and investors in a difficult position, particularly given the scale in question.

68 For example with suppliers in Nigeria and Mozambique.

69 Southall, Lukashuk, (2022). Analysis of Liquid Organic Hydrogen Carrier Systems, https://technology.matthey.com/article/66/3/271-284/

70 See Figure 10.

71 BMWK, (2022). Federal Ministry for Economic Affairs and Climate Action launches first auction procedure for H2Global – €900 million for the purchase of green hydrogen derivatives, https://www.bmwk.de/Redaktion/EN/Pressemitteilungen/2022/12/20221208-federal-ministry-for-economic-affairs-and-climate-action-launches-first-auction-procedure-for-h2global.html

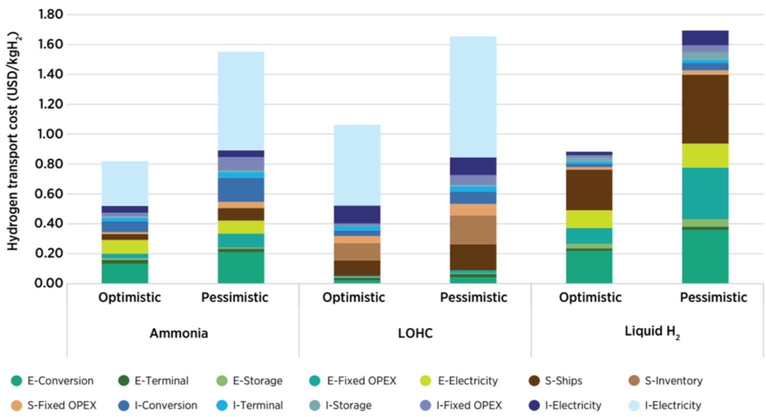
72 See Figure 10 & van der Meulen, et al., (2022). Cost analysis and comparison of different hydrogen carrier import chains and expected cost development, https://zenodo.org/record/6514173#.Y9qOW-zMLlx

There are also some not insignificant but arguably non-terminal technical, economic, and environmental challenges associated with using liquid carriers. For example, NH3 is incredibly toxic[73] and therefore there are strict rules[74] governing its transportation and handling, it also requires ~2850MJ/t of energy to crack it back into hydrogen upon delivery[75]. This energy requirement is felt in the receiving destination where energy prices are likely to be higher and renewable energy scarcer, or a further penalty in the quantity of delivered energy if the shipment itself is used to drive the process.

For LH2 the cost and availability of boats that can handle the cryogenic temperatures is a major technical and economic problem, with these vessels costing as much as 7 to 10x more than NH3 ships[76]. Another major issue for LH2 is the energy penalties, firstly for liquefaction as it must be cooled to -253°C, versus -33°C for NH3 or -164°C for LNG, as well as the energy penalty to pressurise it[77]. However, with cheap and abundant enough renewable energy these issues can be overcome, particularly as the energy penalty is incurred at the point of production rather than delivery, i.e. not in Europe. Shipments of this kind are particularly attractive where there is no overland connection, but the nautical travel required is under 4,000KM where the high 'boil off' rate of LH2 does not become a decisive cost factor[78].

LOHCs do not suffer from the boil off problem and therefore become attractive in very long-distance transmission (assuming the cargo is consumed as shipping fuel), they are also much easier to handle than the alternatives. However, the heat requirement for extracting hydrogen and the scarcity and cost of the carriers themselves undermines their scope for scale[79]. The Figure below gives an overview of these cost components per carrier, note for example the very high electricity cost in the importing country (I) for LOHC and NH3, versus the high conversion and electricity cost in the exporting country (E) for LH2.

Figure 11. Transport cost breakdown by hydrogen carrier, scenario and cost component in 2050, (IRENA, 2022b)



Notes: Costs are for a 1 MtH2/yr export flow and a distance between ports of 10 000 km. Cost components are divided by part of the value chain: E = exporting country; S = ships; I = importing country. Refer to Figure 1.3 for the scope of these costs.

73 New York State, (2011). The Facts About Ammonia, https://www.health.ny.gov/environmental/emergency/chemical_terrorism/ammonia_general.htm#:~:text=Exposure%20to%20high%20concentrations%20of,and%20nose%20and%20throat%20irritation

74 Fertilizers Europe, (2007). Guidance for transporting ammonia by rail, https://www.fertilizerseurope.com/wp-content/uploads/2019/08/Guidance_for_transporting_ammonia_in_rail_4.pdf

75 Black & Veatch, (2022). Ammonia: Fuel vs. Hydrogen Carrier, https://www.bv.com/perspectives/ammonia-fuel-vs-hydrogen-carrier

76 IRENA, (2022b). Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Technology Review of Hydrogen Carriers, https://www.irena.org/publications/2022/Apr/Global-hydrogen-trade-Part-II

77 Air Liquide, (2023). Storing Hydrogen, https://energies.airliquide.com/resources-planet-hydrogen/how-hydrogen-stored

78 IRENA, (2022b). Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Technology Review of Hydrogen Carriers, https://www.irena.org/publications/2022/Apr/Global-hydrogen-trade-Part-II

79 Southall, Lukashuk, (2022). Analysis of Liquid Organic Hydrogen Carrier Systems, https://technology.matthey.com/article/66/3/271-284/

Technological maturity problems also begin to compound due to the complexity of the value chains for shipping relative to pipelines. For example, tankers for LH2 and NH3 are at TRL 11, indicating commercial viability, however, the conditioning process for LOHCs is at 5-7 and ammonia cracking is at TRL 4[80]. Looking a little deeper, although liquefaction of hydrogen is a proven technology (TRL 9), there is only ~350t/d of global liquefaction capacity, and the largest LH2 tank in the world[81] is ~4,700m^3, compared to ~160,000m^3 for LNG[82,83]. Combine this with the lower volumetric energy density of LH2, NH3, and LOHC's relative to LNG[84], and you begin to see the fundamental and critical technical limitations of the technology.

Figure 12. Properties of LNG, LH2, and NH3, (Riemer, Schreiner, Wachsmuth, 2022)

Property (at 1 atm)	Unit	LNG	LH_2	NH_3
Boiling point	°C	-162	-253	-33
Liquid density at boiling point	kg/m³	440-500	71	653-674
Higher heating value at boiling point	MJ/kg	54	142	23
Lower heating value at boiling point	MJ/kg	50	120	19
Volumetric energy density	GJ/m³	23-24	8.5-10	11.5-17*
Heat of vaporization	kJ/kg	502-508	451	1377
Dynamic viscosity (at 20°C, gas)	mPa*s	1.1	0.88	0.99
Flammability range (gas)	%	5 to 15	4 to 75	15-28
Minimum ignition energy (gas)	mJ	0.28	0.02	380-680
Auto-ignition temperature (gas)	°C	599	560	651-1197*
Maximum laminar flame speed in air (gas)	m/s	0.374	2.933	0.07

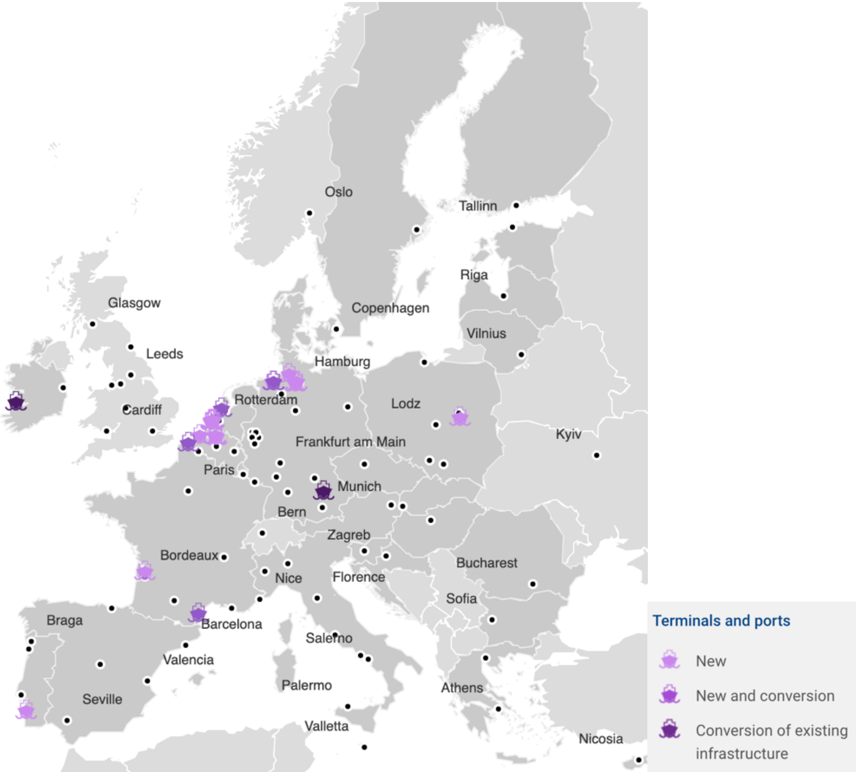
Arguably the clearest illustration of this technical limitation was expressed by IRENA in their 2022 paper on global hydrogen trade[85]. They calculated that if LH2 shipping capacity was able to scale up to the size of the current global LNG fleet (572 vessels), it would be able to deliver 6.5mt/H2/y, or the equivalent of 1% of anticipated global demand in 2050. Moreover, liquid hydrogen has a hydrogen content of 100% but ammonia has a hydrogen content of 17.65%, methanol 12.5%, and 'promising' LOHCs at 5.8 – 7.3%[86,87], making them several fold less capable even than LH2. Considering these factors in combination, it is even clearer how extremely limited the capacity of these carriers is to deliver any meaningful share of the ~12mt of demand forecasted for the EU by 2030. Fundamentally, hydrogen carriers can only play an incredibly limited role in the import market as a function of total demand. This is not an ideological position, but a reflection of technical capacity.

80 I.e. between prototype and demonstration phases.
81 Swanger, (2023). World's Largest Liquid Hydrogen Tank Nears Completion, https://www.cryogenicsociety.org/index.php?option=com_dailyplanetblog&view=entry&year=2022&month=05&day=05&id=48:world-s-largest-liquid-hydrogen-tank-nears-completion#:~:text=Once%20the%20new%20sphere%20is,to%20the%20moon%20and%20Mars
82 Reimer, Schreiner, Wachsmuth, (2022). Conversion of LNG Terminals for Liquid Hydrogen or Ammonia Analysis of Technical Feasibility under Economic Considerations, https://www.isi.fraunhofer.de/content/dam/isi/dokumente/cce/2022/Report_Conversion_of_LNG_Terminals_for_Liquid_Hydrogen_or_Ammonia.pdf
83 Although this is already changing, with tanks of ~70,000m^3 being planned for LH2 tankers.
84 8.5-10 GJ/m^3 and 11.5-17 respectively, versus 23-24 for LNG.
85 IRENA, (2022b). Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Technology Review of Hydrogen Carriers, https://www.irena.org/publications/2022/Apr/Global-hydrogen-trade-Part-II
86 Rao, Yoon, (2020). Potential Liquid-Organic Hydrogen Carrier (LOHC) Systems: A Review on Recent Progress, https://mdpi-res.com/d_attachment/energies/energies-13-06040/article_deploy/energies-13-06040.pdf?version=1605772774#:~:text=Among%20the%20aromatic%20hydrocarbons%2C%20another,wt%25%20(Figure%205)
87 Southall, Lukashuk, (2022). Analysis of Liquid Organic Hydrogen Carrier Systems, https://technology.matthey.com/article/66/3/271-284/

State of play

The Figure below illustrates the import terminal projects already announced at the time of writing, as collected by ENTSOG under their quarterly updated ‘H2 Infrastructure Map’[88,89]. Data is only available for projects planned up to 2030.

Figure 13. Maps of planned hydrogen import terminals in Europe and neighbourhood region based on projects submitted to the ‘H2 Infrastructure Map’ platform as of 11.04.2023 (ENTSOG, 2023)



Most projects are clustered around north-western Europe, except for a terminal planned in the south of Portugal, two in the south of France, one in Poland and another in southern Germany. It appears from the specifications that whilst some projects plan to import pure hydrogen, others favour hydrogen carriers or a combination of pure hydrogen shipments and carrier shipments. Ammonia appears to be the most popular option, based on these project details. The forecasted capacities for the terminals (where indicated) range by a factor of ~1,000, from tens to tens of thousands of GWh/y. The largest indicated capacity is for the ‘ACE Terminal’ in the Port of Rotterdam, which expects a yearly volume of 39,960GWh of ammonia. This equates to ~210,000t/H2/y, or roughly 1.75% of the EU’s projected hydrogen demand.

Infrastructure choices at a glance

There is no clear winner across all priorities, namely: price, security, flexibility, simplicity, scale, safety, and sustainability. Taking price as the key metric, according to different parameters in different scenarios, each carrier could have the advantage and favour for delivering the cheapest *single* tonne. However, there is clarity on limitations, most crucially as regards scale, not the cheapest single tonne but the five millionth tonne.

88 ENTSOG, GIE, Eurogas, CEDEC, GD4S, GEODE, (2023). Hydrogen Infrastructure Map, https://www.h2inframap.eu/#keys

89 There will be some projects planned that are not submitted to the infrastructure map, but this is currently the most comprehensive database for consolidated project data in the EU.

Ultimately, the low hydrogen content of hydrogen carriers[90] and the low capacity of ships to transport large volumes[91] means that it is infeasible for a meaningful share of the EU's estimated ~12mt of hydrogen demand in 2030 to be served by shipped deliveries. Once this limitation is acknowledged, it is clear that the EU will need a minimum of pipelines to serve the bulk of import needs, above which a small share, perhaps less than 5%, could realistically be provided in shipped carriers. In the long term these conditions may begin to change, but this is certainly the outlook for the short to mid-term.

In practice, the following policy implications could guide the rationale and decision making for public support of infrastructure under European funds. For example, the next round of IPCEI's, the TEN-E, InvestEU, TCTF, and the TYNDP[92]. It may also prove instructive for the conditions placed on auctioning and guarantor mechanisms on imports, and CCfDs[93] which appear likely to be structured according to different carriers and vectors.

Policy implications

Reflecting on the data from the previous sections, we draw the following three general guiding principles for infrastructural planning on imports of hydrogen and derivatives.

Hydrogen for hydrogen, derivatives for derivatives

The first takeaway is to try and shift the paradigm for analysis, rather than thinking in only energetic terms with close analogies to natural gas, rather look at the interplay with the standalone derivative markets, the emissions embedded there, and the role for renewable hydrogen in decarbonising them. At the beginning of the 'Transport' section we highlighted a few key underlying principles for the debate on transport and transmission. One of these looks at the energetic losses and wider externalities of conversions between vectors, particularly in an energy scarce context. In the subsequent analysis, we widened the aperture and introduced the issues of logistical and material complications through adding complexity to value chains. The fundamental and underlying point here is that the conversation for liquid carriers of hydrogen overlooks the more obvious function of directly serving the standalone markets for those derivatives.

Consider for example the scenario illustrated below where the production and imports of hydrogen, ammonia, and methanol are not well coordinated. Unnecessary energy losses are incurred due to conversion and reconversion of vectors, as well as additional infrastructure to facilitate the conversion. Both factors will also have an impact on the availability, price, and embedded emissions of each product.

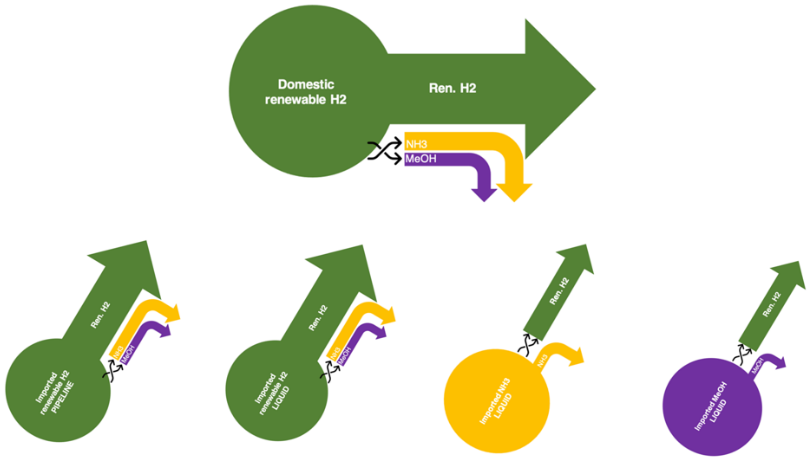
90 Ammonia 17.65%, methanol 12.5%, and LOHCs at 5.8 – 7.3%.

91 The exception here could be liquid hydrogen, where the newest ships have a capacity of up to ~280,000m^3 – equivalent to 20,000t of hydrogen.

92 European Commission, (2023a). Key actions of the EU Hydrogen Strategy, https://energy.ec.europa.eu/topics/energy-systems-integration/hydrogen/key-actions-eu-hydrogen-strategy_en

93 European Commission, (2023b). A Green Deal Industrial Plan for the Net-Zero Age, https://eur-lex.europa.eu/legal-content/EN/TXT/HTML/?uri=COM:2023:62:FIN

Figure 14. Illustrative comparison of energy flows across gaseous and liquid energy vectors: hydrogen (H2), ammonia (NH3), and methanol (MeOH). (Authors own, 2023).



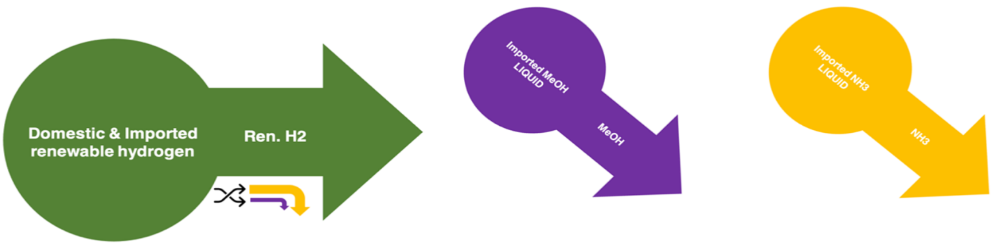
⤨ = A conversion across vectors and therefore a loss in energy content
Note: The flows are only for illustrative purposes and do not reflect proportions of energy, for example.

The ammonia market in the EU is 19mt, most of which is served by imported natural gas feedstock (~10BCM). If renewable hydrogen manufactured abroad would be delivered to the EU as ammonia it could abate emissions directly in that sector and avoid the massive local energy required to crack the ammonia back into hydrogen. As illustrated in the previous section, the low hydrogen content of ammonia (17.65%) makes it quite unsuitable for serving large portions of hydrogen demand but keeping it as ammonia could be a very attractive decarbonisation option. Here are a few key reasons why. Firstly, the final cost is much lower as you eliminate the energy requirement of reconversion in the importing destination (up to 1/3 of the delivered cost). Secondly, the entire delivered volume is useful and saleable, i.e. 100% of the volume rather than 17.65%. Thirdly, the infrastructure and skills are already established for ammonia so it can begin to scale up immediately, potentially also reducing pressure on domestic hydrogen production which may otherwise be used to produce ammonia.

Similar is true for certain LOHCs, for example methanol which has its own market of roughly 10mt in the EU[94], or toluene[95]. As illustrated in the 'Market Outlooks…' section, the majority of existing methanol production is fossil, again based on natural gas feedstock. Importing renewable methanol and using it to directly serve the EU's market can cut the ~40% energy penalty of reconverting it to hydrogen, as well as reducing EU natural gas demand, and again retaining the full useful value of the product not just the portion that is hydrogen (12.5%). It should be noted however that for many LOHCs there is not the same existing market to tap into, giving them a relative disadvantage versus NH3 and methanol in this regard. The Figure below illustrates a scenario where the value chain of each vector is optimised, minimising the need for conversion across vectors.

94 EMR, (2022). Europe Methanol Market Outlook, https://www.expertmarketresearch.com/reports/europe-methanol-market#:~:text=The%20Europe%20methanol%20market%20size,13.25%20million%20tons%20by%202028
95 EMR, (2022). Europe Toluene Market Outlook, https://www.expertmarketresearch.com/reports/europe-toluene-market

Figure 15. Illustrative comparison of energy flows across gaseous and liquid energy vectors: hydrogen (H2), ammonia (NH3), and methanol (MeOH). (Authors own, 2023).



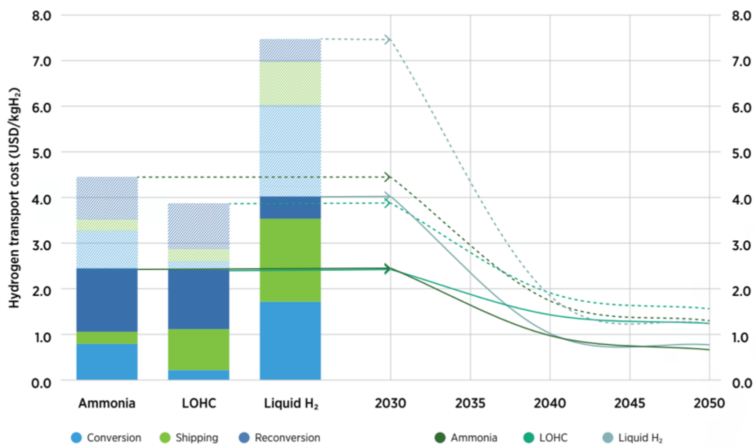
= A conversion across vectors and therefore a loss in energy content
Note: The flows are only for illustrative purposes and do not reflect proportions of energy, for example.

Beyond the energetic and infrastructural efficiencies of keeping derivatives in their shipped state, a further benefit is the scope it provides for experimentation and diversification. These are pretty low risk, no regret options as they are cost effective substitutes for existing and long-term needs, allowing terminals to experiment with processes and see how cost dynamics for different shipped deliveries evolve over time. If in 10 or 20 years a clear winner emerges in the carrier market, Europe will be ready to optimise for that choice, without having over invested in conversion and reconversion infrastructure to commercialise these technologies.

Leverage Europe's competitive advantage in pipelines and allow others to innovate in shipping

Looking at the anticipated cost decrease curves for shipped molecules illustrated below in Figure 16, provoke two key conclusions.

Figure 16. Transport cost breakdown by carrier and stage for 2030 (left) and evolution towards 2050 (right), (IRENA, 2022b)



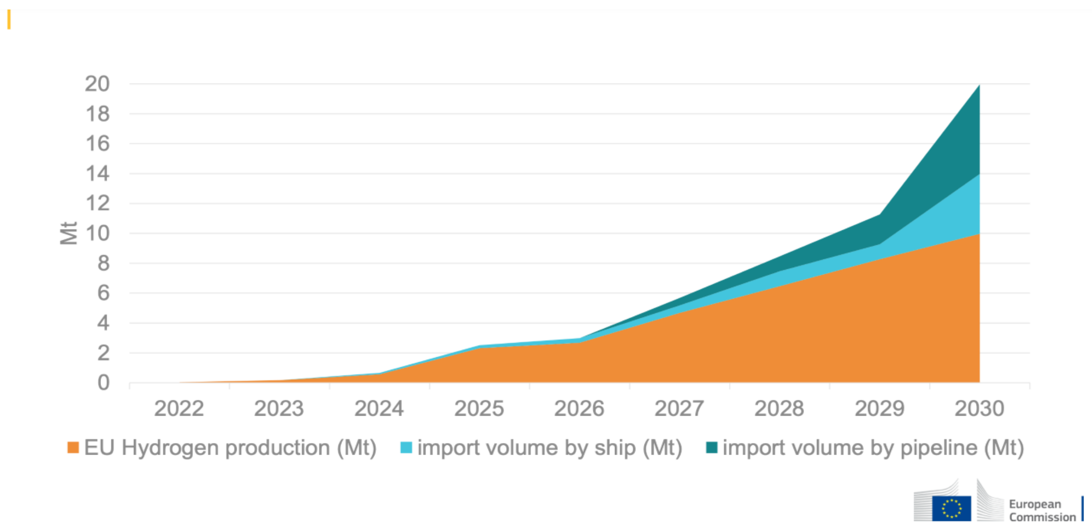
Notes: Solid areas (left) and solid lines (right) represent the most optimistic technology conditions assuming innovation and economies of scale are the most favourable. In contrast, shaded areas (left) and dashed lines (right) represent a pessimistic scenario with lower global co-ordination, less learning and slower innovation. Distance of 10 000 km. Scale of 0.5 MtH_2/yr in 2030 increasing to 1.5 MtH_2/yr by 2050.

Firstly, the cost of shipping is anticipated to drop aggressively from 2030 to 2050, particularly between 2030 and 2040, likely driven by three catalysts: (i) investment in R&D, (ii) 'learning by doing', and (iii) scaling of technology. The more open question is which stakeholders will drive that investment. What can be known for sure is that two categories of stakeholder are compelled to commit to these technology pathways due to their physical geography, (i) exporting islands/remote locations, (ii) importing islands/remote locations[96]. These two groups, including for example actors operating in, Australia, South Korea, Japan, Chile, South Africa, and others, will be required to utilise shipping for transporting hydrogen and its derivatives. This is because most of their partners will not be reachable by pipeline, and as such they are compelled to commit to shipping. This is not the case in the EU, which hosts one of the most elaborate networks of transmission pipelines anywhere in the world, including several interconnections with third countries[97]. Europe does not need be a first mover in shipped hydrogen and reconversion of derivatives.

As illustrated previously, the volumes these liquid carriers can currently deliver are so negligible that it will not make the critical difference in guaranteeing Europe's volumes. Conversely, the learning curve for pipeline transmission is anticipated to much less aggressive, particularly for repurposed assets. As such, it makes more sense to focus on pipelines for hydrogen and shipments for derivatives now, and then look at liquid hydrogen and reconverting derivatives to hydrogen post 2040. At this mid to long-term point, we can expect two key conditions to be met, or at least more clearly clarified. Firstly, that there will be a clearer 'winner' amongst carriers, and secondly that there will be a surplus of renewable electrons in Europe[98] that can be deployed for reconversion of carriers without damaging externalities.

However, it appears that the prevailing view in the European Commission on planning shipped versus piped deliveries of molecules to the EU is quite different, as illustrated by the Figure below.

Figure 17. Anticipated EU hydrogen production volumes and import volumes by delivery type (ship or pipeline) from 2022 to 2030. (European Commission, 2023)



This information is far from conclusive as it comes from a presentation rather than a strategic document, it also only covers plans up to 2030 and does not make a breakdown per carrier, for example. However, it does seem to favour shipped deliveries for the first imported volumes, scaling quite quickly, with pipelines following later. This may be more of a reflection of the time required to repurpose some pipeline assets versus the existing availability of infrastructure to import small volumes of ammonia and other liquid carriers. Nevertheless, we refer to our previous argumentation to indicate the limitations and potentially wasteful externalities associated with this approach, particularly if the trends indicated here were to continue to 2040 and 2050.

96 Geographically 'remote' from hydrogen production or offtake market.

97 GIE, (2023). System Development Map, https://www.gie.eu/publications/maps/system-development-map/

98 Belmans, Dos Reis, Vingerhoets, (2021). Electrification and sustainable fuels: Competing for wind and sun, https://fsr.eui.eu/publications/?handle=1814/71402

Hydrogen does not yet pose a security of supply concern

There is an argument that relying on pipelines for imports for the first phase of the ramp up of the sector is risky from a security of supply perspective. However, if you look at the quantity of hydrogen in the first 10 or so years as a function of total energy consumption, you can see that it will not represent a significant enough share to constitute a credible security of supply concern.

The EU's primary energy consumption is roughly 15,000TWh and is targeted to drop to 14,000TWh by 2030[99]. The 12mt of hydrogen demand forecasted for 2030 equates to roughly 296TWh of energy, or ~2% of primary energy demand, roughly half of which is expected to be domestically sourced. Considering these figures, policy makers should not equate hydrogen to natural gas in terms of rationalising security concerns[100]. By 2050 perhaps hydrogen occupies closer to 10% of primary energy demand, in which case security of supply will warrant greater consideration in decision making processes. By this stage, it is likely that we will have a much clearer answer on the favourable liquid carrier, and the EU will be able to make better informed investments at a much lower cost. These are the learnings we can draw from taking a rationalised, staggered approach to infrastructure planning, considering needs, learning times, and contextualising strategic concerns along a timeline.

Fundamentally, Europe has little choice but to invest in pipeline routes, this is a given based on the current technical limitations of shipping and domestic production. Our observations from the data are that shipped deliveries should be supported, but not for reconversion to hydrogen at this stage, rather for directly substituting their fossil incumbents.

Conclusions

In this paper we have attempted to answer the overriding research question of whether pipelines and shipping are an either-or choice for hydrogen imports to the EU. Very simply put, no, they are not. We established the 'need' of imports at roughly 50% of an anticipated ~12mt of hydrogen demand per year by 2030, potentially rising to ~40mt by 2050. The technical limitations of shipping hydrogen and its derivatives make it completely untenable for meaningful volumes of this to be covered by shipping, essentially for two main reasons. Firstly, the limited transport capacity per ship due to either a low quantity of hydrogen as a share in the overall carrier volume, or technical bottlenecks limiting tank capacities. Secondly, the incidence of sequential maturity and scalability challenges throughout the more complex value chains associated with shipped deliveries makes a fast ramp up from essentially zero to millions of tonnes within the next decade infeasible.

However, shipped deliveries do present competitive economic and strategic advantages relative to pipelines in some cases, with very compelling prospects in the mid to long term, particularly for very long distances. Moreover, hydrogen derivatives, most interestingly ammonia and methanol, have standalone markets of their own in Europe totalling in the tens of millions of tonnes. Our recommendations therefore are that rather than importing these derivatives with a view to converting them back to hydrogen, they are rather sold directly into the derivatives markets, displacing the incumbent fossil alternatives. This could have several wider benefits, firstly by reducing natural gas imports, as ammonia and methanol are primarily produced by imported natural gas. Secondly, there are established infrastructure and skills in Europe for handling these derivatives, and as such they can directly and quickly begin decarbonising those sectors, also taking stress off domestic hydrogen to serve the same function. Thirdly, the massive energy cost of reconverting carriers back into hydrogen would potentially create significant externalities for the allocation of renewable electricity or industrial heat in Europe. Avoiding this step in the process not only cuts costs and infrastructural complexity, but also avoids massive energy and heat demand at a time when renewable energy is scarce in Europe.

99 EEA, (2022). Primary and final energy consumption in Europe, https://www.eea.europa.eu/ims/primary-and-final-energy-consumption
100 Florence School of Regulation, (2023). Security of Supply: Gas, https://fsr.eui.eu/security-of-supply-gas/

Ultimately, islands and remote locations that wish to import or export hydrogen and derivatives have no choice but to invest in shipping, this is not the case in Europe. Conversely, the EU and its wider neighbourhood region can leverage an almost unparalleled network of transmission infrastructure, comfortably capable of delivering the large volumes of cost-effective hydrogen required. Although pipelines risk overreliance on a few suppliers, at ~1% of primary energy demand in 2030, imported hydrogen is arguably not likely to be a major security of supply concern. By the time this share increases towards 10% by 2050, there will be much greater clarity on effective and scalable shipping options and Europe can work towards diversification. Moreover, by this point Europe is much more likely to be in a renewable energy surplus, where reconversion of carriers back to hydrogen will not cause the same damaging externalities.

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