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

PART II

TECHNOLOGY REVIEW OF HYDROGEN CARRIERS

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ABBREVIATIONS

AB	1,2-dihydro-1,2-azaborine
ABS	American Bureau of Shipping
AiP	Approval in Principle
ASU	Air separation unit
BECCS	Bioenergy with carbon capture and storage
BT	Benzyltoluene
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CH2	Compressed hydrogen
CNG	Compressed natural gas
CO	Carbon monoxide
DAC	Direct air capture
DACCS	Direct air capture with carbon capture and storage
DBT	Dibenzyltoluene
DME	Dimethyl ether
dwt	Deadweight tonnage
FCEV	Fuel cell electric vehicle
GHG	Greenhouse gas
HFO	Heavy fuel oil
Hx	Heat exchanger
ICE	Internal combustion engine
IGC Code	International Gas Carrier Code
IGF Code	International Code of Safety for Ship Using Gases or Other Low-Flashpoint Fuels
IMO	International Maritime Organization
IPCEI	Important Projects of Common European Interest
ISO	International Organization for Standardization
H_2	Hydrogen
LH2	Liquid hydrogen
LHV	Lower heating value
LNG	Liquefied natural gas

LOHC	Liquid organic hydrogen carriers
LPG	Liquefied petroleum gas
MGO	Maritime gasoil
MoU	Memorandum of understanding
MR	Mixed refrigerant
NAP	Naphthalene
NEC	N-ethylcarbazole
NEDO	New Energy and Industrial Technology Development Organization
NH_3	Ammonia
NO_x	Nitrogen oxides
N_2	Nitrogen
OPEX	Operational expenditure
PEMFC	Polymer electrolyte membrane fuel cell
ppm	Parts per million
PSA	Pressure swing adsorption
PV	Photovoltaic
SMR	Steam methane reforming
SOFC	Solid oxide fuel cell
STY	Space time yield
TCO	Total cost of ownership
TEU	Twenty-foot equivalent unit
THF	Tetrahydrofuran
TRL	Technology readiness level
TSO	Transmission system operator
ULCC	Ultra-large crude carriers
VLCC	Very large crude carrier
VLSFO	Very low sulphur fuel oil

Units of measure

bbl	Barrel
cm	Centimetre
d	Day
g	Gram

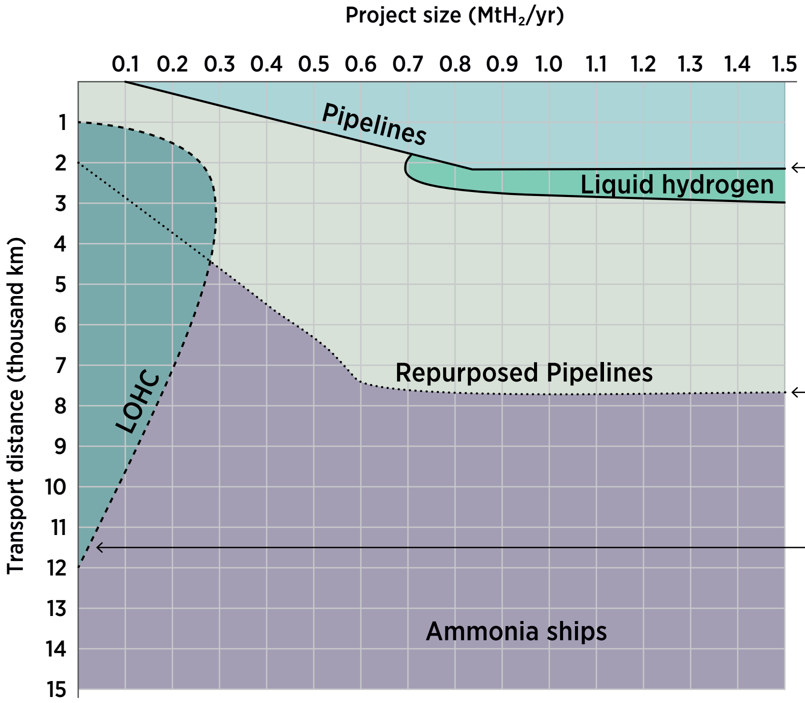
GJ	Gigajoule
Gt	Gigatonne
$GtCO_2$	Gigatonne of carbon dioxide
GW	Gigawatt
hr	Hour
K	Kelvin
kcal/mol	Kilocalories per mole
kg	Kilogram
km	Kilometre
kW	Kilowatt
kW_{el}	Kilowatt electrical
kWh_{el}	Kilowatt hour electrical
kWh/L	Kilowatt hours per litre
kWH_2	Kilowatt of hydrogen
m	Metre
MJ	Megajoule
MMBtu	Million British thermal units
MPa	Megapascal
Mt	Megatonne
$MtCO_2$	Megatonne of carbon dioxide
MtH_2/yr	Megatonnes of hydrogen per year
MW	Megawatt
MWh	Megawatt hour
m^3	Cubic metre
Nm^3	Normal cubic metre
t	Tonne
t/d	Tonnes per day
yr	Year

EXECUTIVE SUMMARY

Hydrogen can be transported across long-distances by pipeline or by ship. This report compares the transport of hydrogen by pipeline as compressed gaseous hydrogen with three shipping pathways: ammonia, liquid hydrogen and liquid organic hydrogen carriers (LOHC). The focus is on hydrogen transport rather than the transport of commodities made using hydrogen (e.g. iron), noting that ammonia can be both a hydrogen carrier and directly used as a feedstock or fuel for different applications. Carbon-containing carriers (such as methanol or methane) are excluded since they would need a sustainable carbon source (biogenic or directly from air) to be considered renewable, and the cost advantages are not sufficient to compensate for this downside. The scope covers transformation from gaseous hydrogen to a suitable form to allow its transport and storage, its use in the transport step itself, and its reconversion from the carrier back to pure hydrogen (if needed).

There are two main parameters that define the transport cost: the size of the production facility and the transporting distance. The size defines the economies of scale, and the larger the production facility's size the lower the specific cost. The largest available benefit is achieved with project sizes of 0.4, 0.4 and 0.95 MtH_2/yr for LOHC, ammonia and liquid hydrogen respectively. To put these values into perspective, 1 MtH_2/yr would be equivalent to a 10 GW electrolyser running for about 60% of the year, or the hydrogen consumption of five commercial ammonia plants. These sizes translate into a cost reduction of up to 80% compared to today's pilot projects. Figure 0.1 shows how the technology pathways compare in 2050. Identifying the most attractive pathway by 2050 allows the greatest benefits in the long term to be identified and defines where to focus short-term efforts.

FIGURE 0.1. Most cost-effective hydrogen transport pathway in 2050 as a function of project size and transport distance



Solid lines are the base case. Pipelines are attractive for short distances, liquid hydrogen has a niche role and ammonia shipping is the most attractive for most combinations

Dotted lines are for regions that have an existing network that can be repurposed to hydrogen, expanding significantly the area where pipelines are attractive

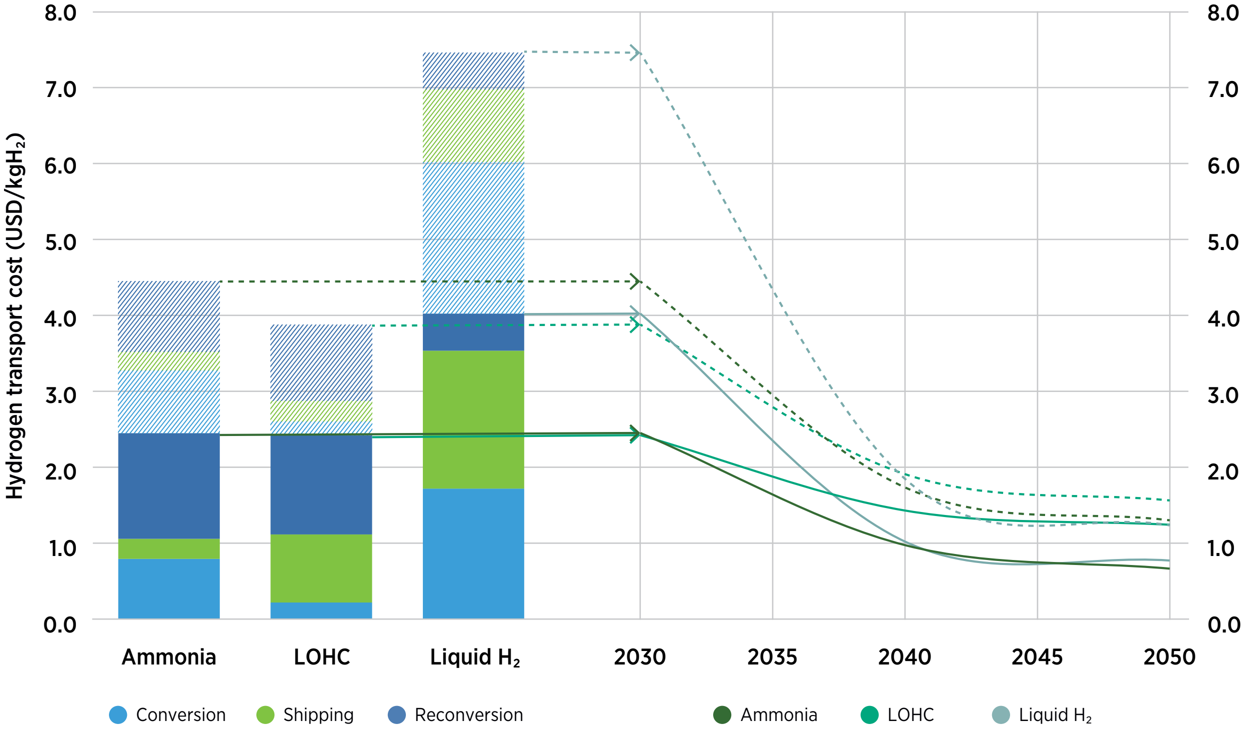
Dashed lines represent a case where innovation is slower and all the costs are higher. In this instance, LOHC can be attractive for smaller projects

Ammonia ships are the most attractive for a wide range of combinations. The shipping cost is relatively small compared to the cost of conversion to and from ammonia and the ammonia storage cost. Thus, longer distances have limited impact on the total cost, making it more attractive as the distance increases. The cost for pipelines, on the other hand, scales linearly with distance, which is why they are the cheapest option for short distances of up to 3 000 km. The cost of pipeline transport varies according to the flow transported – double the diameter means roughly double the cost but four times the flow, which reduces the specific cost per unit of hydrogen transported. For this reason, the distance at which pipelines are the most attractive expands as the project size increases. In cases where repurposed pipelines are possible (e.g. North America, Europe or eastern China), the investment cost can be 65-94% lower than the cost of a new hydrogen pipeline. This significantly expands the distance along which pipelines are attractive to up to 8 000 km. This is almost double the distance from Ukraine to Spain or from the east to the west coast of the United States. While attractive in terms of cost, it is limited by the existing infrastructure and relies upon a simultaneous (both geographically and in time) decrease in methane demand. Even for distance and flow combinations where ships are the most attractive, pipelines can still play a role in transporting the hydrogen inland to demand centres that are not on the coastline.

The main disadvantage of shipping liquid hydrogen lies in the low temperature requirement (-253°C). This translates into high energy consumption for liquefaction (currently equivalent to 30-36% of the energy contained in the hydrogen) and a high cost for all the equipment, since it needs to be designed for the cryogenic conditions. This makes liquid hydrogen attractive for relatively short distances as longer routes would require more ships to maintain a continuous flow. Short distances are the also where pipelines are most attractive. In instance where pipelines are not an option (e.g. an island, Japan, South Korea), then liquid hydrogen can be attractive for large flows and distances of up to around 4 000 km.

LOHC are oil derivatives, can use existing facilities, are stable compounds and do not have any boil-off losses during transport or storage. However, they face multiple challenges. Sustainable pathways for the carriers have not been proven. While the carrier can be reused, there are losses (0.1% per cycle) that would require compensating for. Most are speciality chemicals that are produced in limited quantities and would require the scaling up of production multiple times just to satisfy this new market. Most of the carriers also have a high cost, which leads to a high initial cost due to the need for inventory. They all have a relatively low hydrogen content (4-7% by weight), which translates into the need to transport a large mass of LOHC. Lastly, they require heat, equivalent to 30-40% of the energy contained in the hydrogen, to recover the hydrogen from the carrier. In short, this pathway presents multiple challenges that can limit its role in the global hydrogen trade.

FIGURE 0.2. Transport cost breakdown by carrier and stage for 2030 (left) and evolution towards 2050 (right)



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.

Figure 0.2 shows the cost by 2030, when the pathways are expected to be transitioning from pilot scale to commercialisation. By then, the most attractive carriers are ammonia and LOHC with a transport cost (excluding hydrogen production) of USD 2.5-4.5/kgH_2 (for 10 000 km). The lower bound represents the most optimistic yet realistic scenario, where innovation has led to technology improvement and various pilot projects have built up experience with the technologies. At this point, liquid hydrogen has a higher cost mainly because it requires a larger scale than is expected to be reached by 2030.

Three levers are available to reduce the transport cost towards 2050. The first is innovation to reduce the energy consumption for the liquefaction of hydrogen and the conversion to ammonia and LOHC, and then reconversion to hydrogen. These are the most energy-intensive steps in each value chain. Not all the steps in the value chain are proven. The direct use of ammonia in ships still needs to be de-risked (expected to be ready by 2024), as does the reconversion. For LOHC, production supply chains need to be scaled up and demonstrate the (re)conversion steps on a large scale. Liquid hydrogen is already proven commercially, but far from the scale needed for global trade, which could pose additional risks, and liquid hydrogen shipping needs to be demonstrated. The second lever is economies of scale. This lever alone could achieve cost reductions of up to 80% by reaching the largest possible scale for each part of the value chain. The third lever is learning-by-doing. Developing global experience and sharing lessons lead to a cost decrease from initial projects that have no previous reference, from a tailored design to a standard, and to a modular approach for many pieces of equipment.

If all these drivers are in place, transport costs could fall to levels of USD 0.7-1.2/kgH_2 by 2050 (for 10 000 km) in the most optimistic conditions. However, they could also be higher at USD 1.3-1.6/kgH_2 for a scenario with less innovation and global co-ordination. This places the transport cost roughly in the same order of magnitude as production cost, which means an exporter should have around half (depending on the distance) of the production cost of an importer to be attractive. This is still far from the reality today, where there are only pilots for some of the steps. It could therefore change drastically depending on how technology evolves towards 2050.

Looking at the short term, ammonia and existing pipelines appear to be the best places to start. Over 120 ports already have ammonia infrastructure and 10% of global production is already traded. Once renewable ammonia is produced, it could be blended at any ratio with fossil-based ammonia without any change in properties (with a certification scheme in place), making initial trade easier. Ammonia has an existing market of 183 million Mt/yr, which is expected to grow to over 600 Mt/yr by 2050. This means it does not need to be reconverted to hydrogen (and lose 13-34% of the energy), but can be used directly to reduce the overall energy consumption along the value chain. This is an advantage that neither LOHC nor liquid hydrogen have. Existing pipelines can also be repurposed as natural gas demand starts to dwindle. Europe already has experience of repurposing pipeline from natural gas to hydrogen (in the Netherlands), and there are plans to establish a regional network.

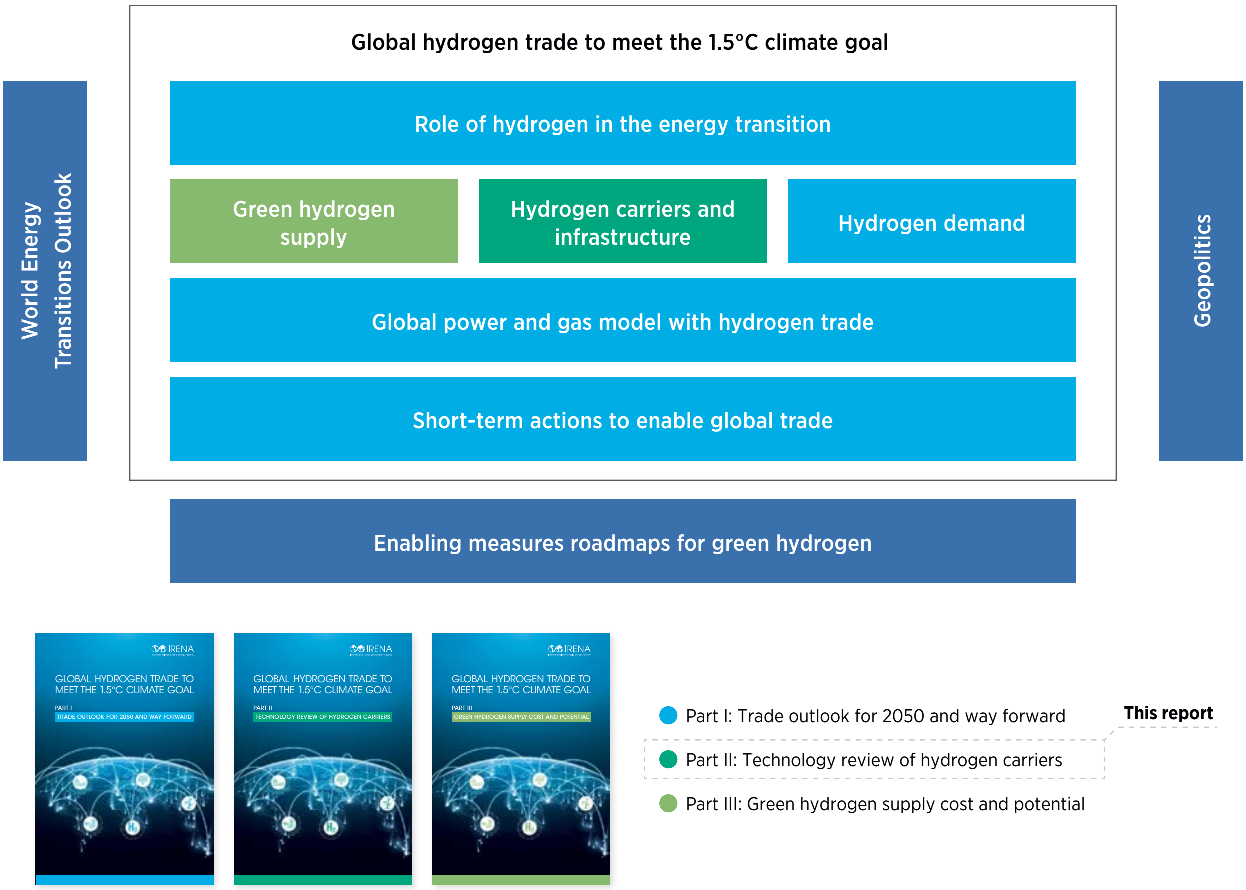
Like ammonia, which does not require reconversion to hydrogen, other commodities are available that might be more attractive for transport. The transport of hydrogen is not the ultimate objective, but instead the transport of renewable energy from low-cost locations to demand centres. This can be done by further transforming hydrogen to the final form in which the energy will be used, and which is more cost-effective to transport due to a higher energy density. This can be the case for iron (or steel), methanol used as feedstock, or synthetic fuels for aviation. All these commodities will certainly be needed in the future since there are limited or no substitutes, can be derived from hydrogen, and have a lower transport cost. This will be the subject of future IRENA publications.

CONTEXT OF THIS REPORT AND WHAT TO EXPECT

The *Global Hydrogen Trade to Meet the 1.5°C Climate Goal* report is divided in three parts (see Figure 0.3). The first one integrates all the components: supply and infrastructure from the other two reports in the series with demand from IRENA WETO 1.5°C Scenario (IRENA, 2021a), to assess the outlook of global hydrogen trade by 2050 looking at the cost and technical production potential of green hydrogen for the world in 2030 and 2050 under different scenarios and assumptions (IRENA, 2022a). The second one (this report) looking at the state-of-the-art of literature about hydrogen infrastructure under four different technology pathways. The third one covers the cost and technical potential of green hydrogen supply for various regions and time horizons under different scenarios and assumptions (IRENA, 2022b).

The *Global Hydrogen Trade to Meet the 1.5°C Climate Goal* report is closely related to other IRENA publications. The *World Energy Transitions Outlook* (IRENA, 2021a) provides a perspective on the role of hydrogen within the wider energy transition in a scenario in line with a 1.5°C pathway. It covers all the energy sectors and includes the trade-off between hydrogen and other technology pathways (e.g. electrification, carbon capture and storage, bioenergy).

FIGURE 0.3. Scope of this report series in the broader context of IRENA publications



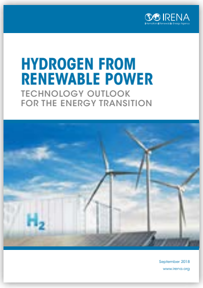
While there are measures that are applicable at the global level (e.g. certification), some of the measures will be country specific depending on the local conditions, including the energy mix, natural resources and level of mitigation ambition, among others. Thus, the global toolbox of enabling measures needs to be adapted to the local context. IRENA has already done this for Europe and Japan (IRENA, 2021b), with more regions to be analysed in the coming months.

Hydrogen trade will be defined not only by production and transport costs, or the comparison of domestic and import costs. Other factors, such as energy security, existence of well-established trade and diplomatic relationships, existing infrastructure and stability of the political system, will also have a large impact on the trade partners each country chooses to have. Therefore, the actual trade partners will probably look different from the ones presented in this report, since these "soft factors" are not considered in the model, which is based on pure cost optimisation. These geopolitical factors are covered in a separate report (IRENA, 2022c) as part of IRENA's Collaborative Framework on Geopolitics.

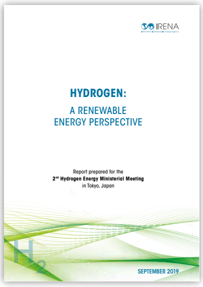
The present report covers various technology options to transport hydrogen across long distances and in large volumes. Different carriers are screened (Section 1) and three carriers (liquid hydrogen, liquid organic hydrogen carriers [LOHC] and ammonia) for seaborne transport are explored in more detail (Sections 2 to 4). For each of these pathways, the latest status of the technology, projects and gaps to be closed are reviewed for the three parts of the value chain: transformation from gaseous hydrogen to a form suitable for transport, shipping, and transformation from the transported form of hydrogen back to pure hydrogen. Storage, which is an essential component of the infrastructure at ports, is also reviewed for each carrier. The review includes a survey of several references for capital cost and energy consumption for each step and defines possible ranges for these values in the future. For many regions, importing hydrogen not only means ships, but also land-based import through pipelines, including repurposing parts of the existing gas infrastructure for hydrogen (Section 5).

The most cost-effective technology will not only depend on the technology's performance over time, but also on the specific volume to be transported and distance to be covered. The comparison is made separately between shipping alternatives (Section 6.1) and between shipping and pipeline (Section 6.2). At the same time, there is great uncertainty as to how technology might evolve over the coming decades, so the main levers for cost reduction are identified (Section 6.3).

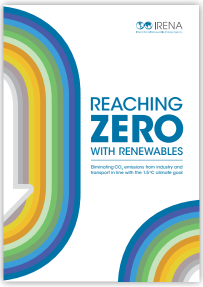
This report is part of IRENA's ongoing programme of work to provide its member countries and the broader community with expert analytical insights into the potential options, the enabling conditions and the policies that could deliver the deep decarbonisation of economies. Green hydrogen, being an indispensable element of the energy transition, is one focus of IRENA analysis. Recent IRENA publications include:



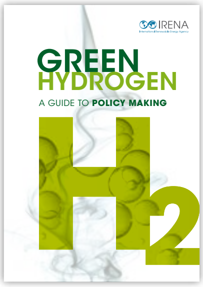
Hydrogen from Renewable Power (2018)



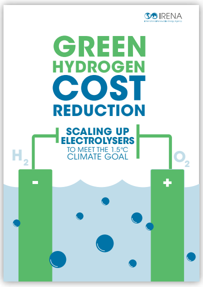
Hydrogen: A renewable energy perspective (2019)



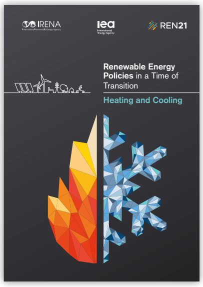
Reaching Zero with Renewables (2020) and its supporting briefs on industry and transport



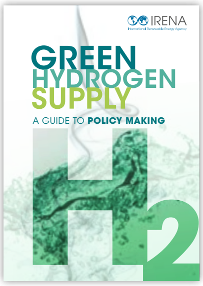
Green Hydrogen: A guide to policy making (2020)



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

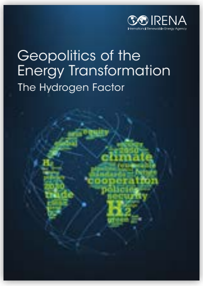


Renewable Energy Policies in a Time of Transition: Heating and cooling (2020)

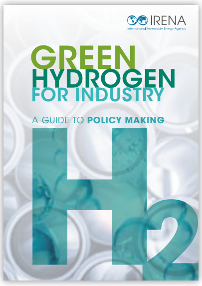


Green Hydrogen Supply: A guide to policy making (2021)

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



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



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

These reports complement IRENA's work on renewables-based electrification, biofuels and synthetic fuels and all the options for specific hard-to-abate sectors.

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

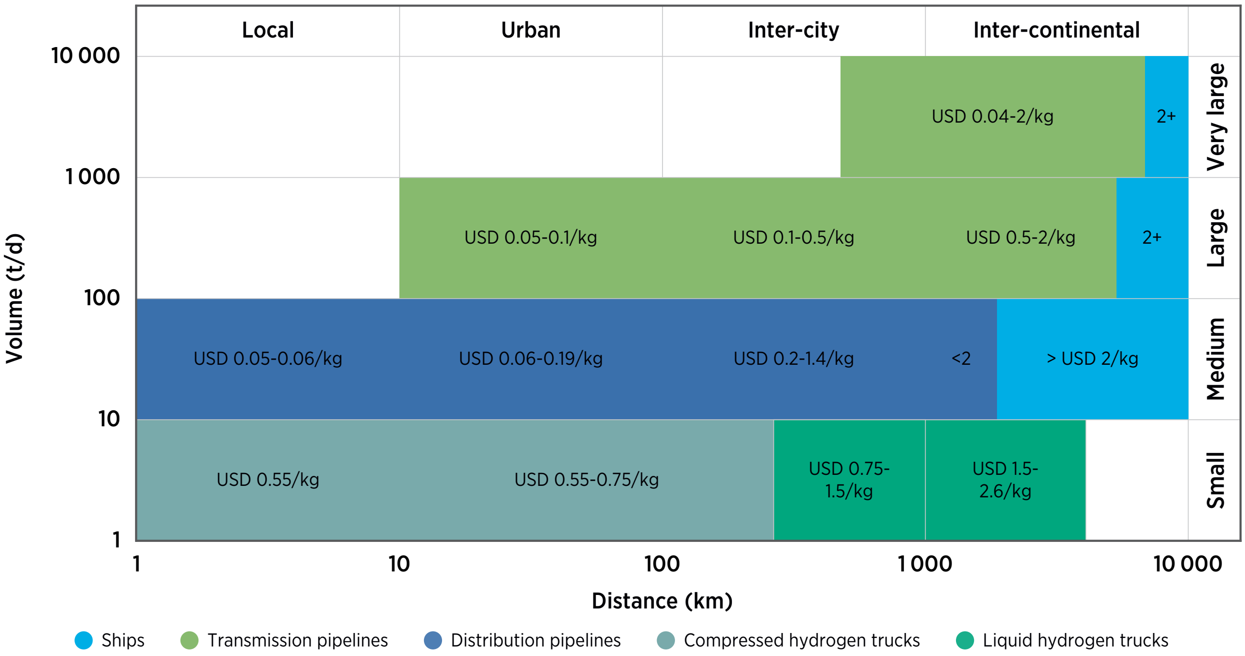
1

TECHNOLOGY PATHWAYS FOR INFRASTRUCTURE DEVELOPMENT

TECHNOLOGY PATHWAYS FOR INFRASTRUCTURE DEVELOPMENT

The total cost of hydrogen delivered to a specific country has two components: production and transport. While Part III of this report series covers the production cost by region and production pathway (IRENA, 2022b), this part covers the transport component. The transport cost is mainly a function of two parameters[1]: volume transported and distance (see Figure 1.1). There are three ways of transporting hydrogen: via truck, pipeline or ship.[2] For small volumes and short distances, trucks can be attractive, but as the volume increases, the density needs to be increased and trucks carrying liquid hydrogen need to be used. Further increases in volume or distance make pipelines the most cost-effective route, graduating from distribution pipelines (i.e. small diameter) to transmission pipelines as the volume increases. For very long distances or routes across water bodies, ships become the most attractive. Therefore, for most cross-border trade, trucks can be discarded since they are suited to smaller volumes.

FIGURE 1.1. Hydrogen transport cost based on distance and volume



Notes: A typical pressure for compressed hydrogen trucks is 500 bar for a 1.1 t capacity (Wulf et al., 2018).
Source: (Energy Transition Commission, 2021a; Li et al., 2020).

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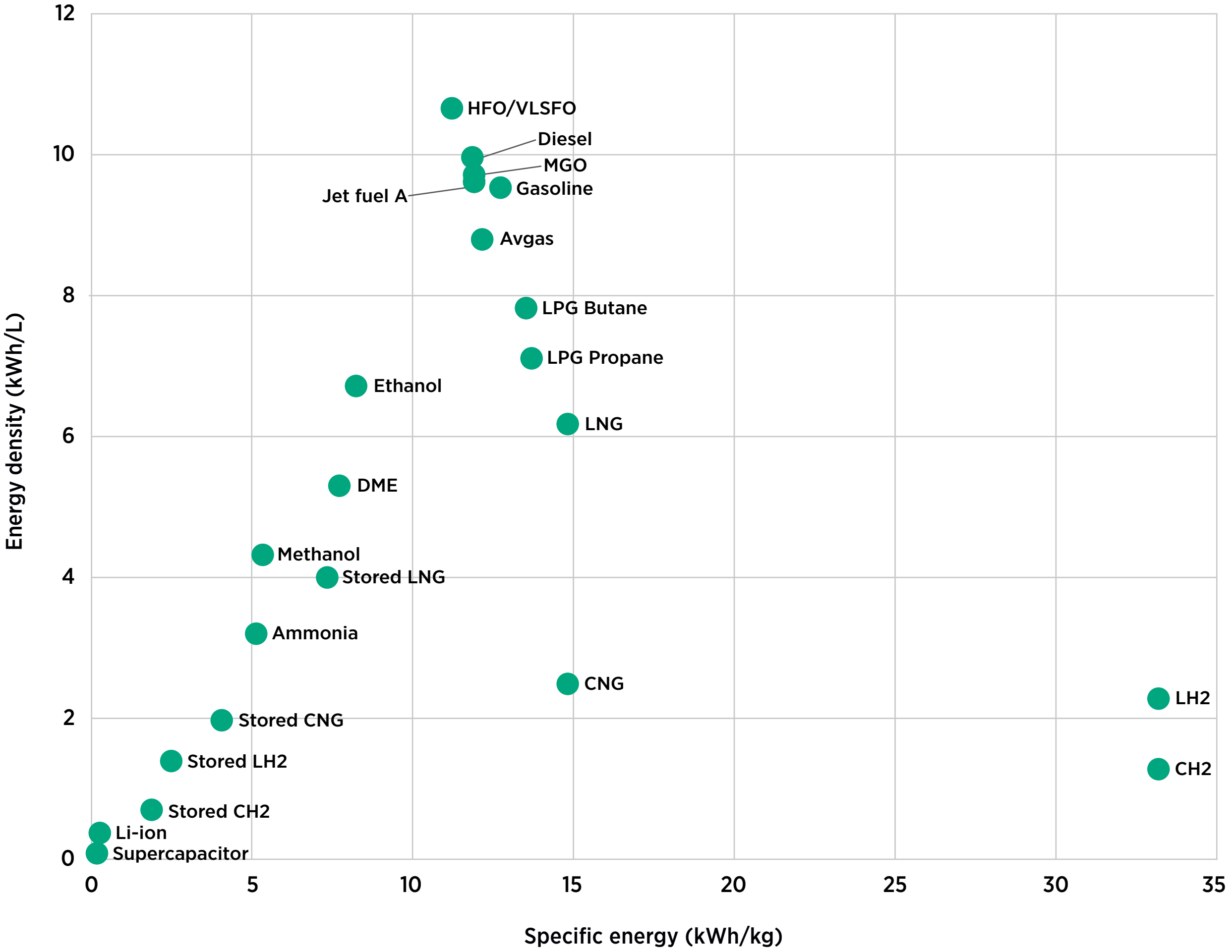
[1] There are other geographical factors such as elevation, type of terrain and water depth, and market-based factors such as tariffs and fees, which can affect the cost of pipelines but are region- or route-specific and are left out of the scope of this study.

[2] Rail is also an option with an energy efficiency similar to ships (IEA, 2019a), but it has more limited capacity than pipelines and is excluded from this analysis. Previous analyses have shown that ammonia by rail has a lower cost per unit of hydrogen (Papadias, Peng and Ahluwalia, 2021).

Hydrogen transport is challenged by its low volumetric energy density.[3] Hydrogen is found as a gas at standard conditions (atmospheric pressure and 0°C). Using this as a reference, batteries have about 220 times higher energy density and jet fuel almost 3 000 times higher (Energy Transition Commission, 2021a). Hence, hydrogen must be compressed, liquefied or converted to other molecules to be transported economically.[4] Regarding compression, typical pressures are 70-100 bar for transport by pipeline and 350-700 bar for road transport applications (350 bar mostly for buses and trucks and 700 bar for passenger vehicles). This would already reduce the volume by 95, 290 and 500 times respectively compared to hydrogen at atmospheric pressure. Liquefying it can reduce the volume by almost 800 times, but the largest volume reduction would be achieved by converting it into other carriers. Ammonia is 1 800 times denser than atmospheric hydrogen, methanol about 2 500 times and jet fuel 3 000 times (see Figure 1.2).

FIGURE 1.2. Energy density and specific energy for various fuels and energy storage systems



Notes: Avgas = aviation gasoline; CH2 = hydrogen compressed at 70 MPa; CNG = natural gas compressed at 25 MPa; DME = dimethyl ether; HFO/VLSFO = heavy fuel oil/very low sulphur fuel oil; LH2 = liquefied hydrogen; Li-ion = lithium-ion battery; LNG = liquefied natural gas; LPG = liquefied petroleum gas; Stored CNG = Type IV tank at 250 bar; Stored CH2 = best available CH2 tanks at 70 MPa; Stored LH2 = current small-scale LH2 on-board tanks; Stored LNG = small-scale storage at cryogenic conditions; MGO = maritime gasoil. Numbers are expressed on a lower heating value (LHV) basis. Weight of the storage equipment is included.
Sources: Energy Transition Commission (2021a); Hurskainen (2019); IEA H2 TCP (2021); Philibert (2020); Royal Society (2020).

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[3] This report uses the terminological convention of energy density when referring to volumetric energy density (MJ/m^3) and specific energy when referring to gravimetric energy density (MJ/kg).

[4] Other options include the use of solids in the so-called hydrides, zeolites, metal organic frameworks or carbon nanotubes, but those have a relatively low level of technological development (most of them with a technology readiness level of 3) (Demirci, 2018).

The trade-off is between ease of transport and storage on the one hand, and cost and energy consumption on the other. Ideally the inefficiency of transforming hydrogen only for the purpose of transporting it would be avoided, but hydrogen's low energy density makes it economically unattractive to transport. Thus, an energy penalty is incurred, increasing the energy input for the benefit of lower transport cost. This energy penalty can be only a few percentage points for pipelines, 30-36% for hydrogen liquefaction today and almost 50% for the round-trip efficiency of ammonia (albeit improving if cracking is not needed). Thus, the energy density (and corresponding energy loss) will depend on the volume to be transported, the distance and the form of the final energy demand. For instance, if steel is the final product, it makes more sense to transport either the reduced iron (in the form of hot briquetted iron) or the steel itself rather than to transport hydrogen and the iron ore separately (Devlin and Yang, 2022; Philibert, 2021).

1.1 Overview of possible technologies for shipping

Compressed hydrogen

For transport by ship, hydrogen needs to be transformed into a form with higher energy density and then reconverted at the importing terminal.[5] The least energy-intensive option would be to compress it. This option is being explored by Global Energy Ventures, a company that has filed a patent for a ship designed to carry compressed hydrogen and also has a ship designed for CNG. It claims that achieving distances of up to 8 500 km in a competitive way is possible using a ship carrying 2 000 t of H_2 (250 bar) powered by a fuel cell and the cargo (GEV, 2021). The company also claims to have received approval of the design by a maritime classification society in March 2021 (Hydrogen Central, 2021). As an intermediate step to reach this large scale, a 430 t design was proposed and received preliminary approval by the American Bureau of Shipping (ABS, a maritime classification society) in October 2021, aiming for Full Class approval by late 2022.

This pathway creates the lowest energy density, which means it also contains the lowest mass of hydrogen. If the hydrogen cargo were used as fuel for the ship, it would be quickly consumed and leave little to actually deliver at its destination. If hydrogen is compressed to 275 bar (a similar pressure to CNG ships), the maximum shipping distance (consuming all the cargo and not leaving anything to be delivered) is 2 600 km (assuming a ship size of 2 700 m^3 or about 50 tH_2) (d'Amore-Domenech, Leo and Pollet, 2021). Other studies show that not even journeys of 1 000 km can be completed (ICCT, 2022). This means the cost per unit of hydrogen delivered increases significantly as the distance increases (since the cost remains fixed and less hydrogen is delivered). Furthermore, most of the relevant shipping routes are above 5 000 km. Considering both factors, compressed hydrogen ships are not attractive for large-scale, long-distance trips and are not considered further in this study.

Oxygenated products

Although oxygenated products like methanol, ethanol and DME could also be used, a common disadvantage these have is that once the hydrogen is extracted from the carrier, there is carbon left that will be released as CO_2. This means that either carbon capture and storage (CCS) is needed at the importing terminal or the carbon has to be originally sourced from the atmosphere

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[5] Ammonia reconversion (i.e. cracking) can be prevented by using ammonia directly. This is not possible for liquid hydrogen or LOHC.

(either biogenic or via direct air capture) to avoid increasing net CO_2 emissions. Considering a reference flow of 100 MtH_2/yr of transported methanol, approximately 0.73 Gt of air-captured or biogenic CO_2 would be needed for the methanol production. By 2050, 4.7 $GtCO_2$ of negative emissions are needed in a 1.5°C scenario (IRENA, 2021a), which will be mainly through bioenergy with carbon capture and storage (BECCS) or potentially direct air capture with CCS (DACCS) if it develops fast enough. At the same time, there is no large-scale deployment of these technologies today. Hence, any additional CO_2 that needs to be captured for methanol would only add further capacity needs to the already ambitious BECCS and DACCS levels. Additionally, the cost penalty introduced by the CO_2 source would be significant. In the long term, the levelised cost of DAC could reach levels of USD 100/tCO_2 (Keith et al., 2018). This would translate into about USD 140/t of tCH_3OH, equivalent to about USD 0.75-1.25/kgH_2. To put this into perspective, current fossil-based methanol has a production cost of USD 100-250/tCO_2 (IRENA, 2021c). Based on these two constraints, oxygenated products are not further considered in this study.

Methane

Another option is methane, but this presents the same challenges as the compounds above. Additionally, any methane leakage that takes place during transfer or slip from the engine would increase greenhouse gas (GHG) emissions for the pathway. This pathway is sensitive to the methane loss rate because methane has 29.8 times more global warming potential than CO_2 (for a 100-year time horizon [IPCC, 2021] which increases to 82.5 for a 20-year horizon). Furthermore, methane as a hydrogen carrier would lead to significant inefficiencies if the initial hydrogen is produced from natural gas. Instead of the double hydrogen production, the initial methane could be directly transported as LNG, but this means the CO_2 released upon reconversion at the importing terminal would be fossil CO_2 requiring permanent sequestration. The importing country might not have enough sequestration capacity (e.g. both Japan and South Korea have limited CO_2 storage capacity [Kearns et al., 2017]) or might face social opposition to the technology.

Carbon shipping

An alternative option is to export the fossil natural gas and import back the CO_2 generated after hydrogen production. This has already been proposed from Saudi Arabia to South Korea (Bloomberg, 2021) (using the CO_2 for enhanced oil recovery). A limitation of this route is that the volume of CO_2 produced is higher than the volume of the exported LNG,[6] which would pose a logistics limitation. Furthermore, an LNG carrier is usually designed for atmospheric pressure, while liquid CO_2 requires pressurised tanks at up to 70 bar (BEIS, 2018) (at atmospheric pressure CO_2 exists as either gas or solid and transport in these states is not cost-effective [Geske, Berghout and van den Broek, 2015]). Furthermore, its low technology readiness means this route might be ready just when the renewable hydrogen route has undercut the fossil-based route. It is also possible to import methane and use pyrolysis where the carbon ends up as a solid (carbon black). However, this technology has a low technology maturity and is still far from a commercial scale (Schneider et al., 2020). Therefore, this pathway is not explored further in this report.

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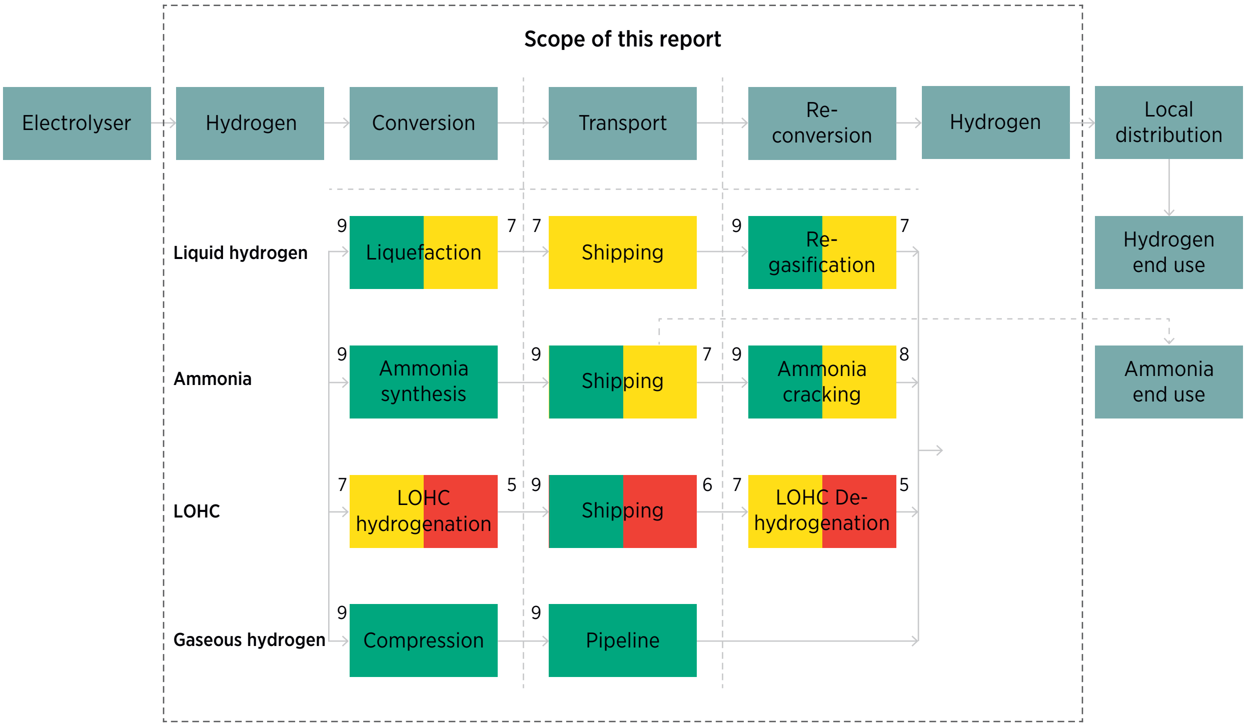
[6] A typical LNG carrier of 200 000 m^3 would be the equivalent of 90 kt of LNG (450 kg/m^3), which would produce almost 500 kt CO_2 and occupy 450 000 m^3 as liquid CO_2 (1100 kg/m^3).

Ammonia, LOHC and liquid hydrogen

This leaves three remaining options for transporting hydrogen by ship: ammonia, liquid organic hydrogen carriers (LOHC) and liquid hydrogen. Each of these pathways requires three steps: transforming gaseous hydrogen to the form and conditions suitable for transport; the transport step itself; and reconverting the carrier to pure gaseous hydrogen under the required conditions (see Figure 1.3). Each of these carriers has at least one step of the value chain that needs further Research and Development (R&D) to reach a fully commercial scale.

FIGURE 1.3. Processing steps of the hydrogen value chain for each of the hydrogen transport options.



Notes: Colour code is a traffic light convention for technology maturity based on technology readiness level (TRL), which is a scale from 1-9 (sometimes up to 11) with the maximum meaning commercial scale. Green = TRL 9; yellow = TRL 7-8; red = TRL 6 or less. For more information see (GAO, 2020; Mankins, n.d.). Colour on the left of each box means small-scale plants and colour on the right means large-scale plants (1000+ t/d of hydrogen). TRL number is provided at the top of each process step. Yellow for ammonia shipping and LOHC shipping refers to the use of cargo as fuel (in engines and fuel cells respectively). Storage is not included to simplify the figure, since all the pathways have demonstrated it at scale. Hydrogen liquefaction is already carried out, but further research is needed to decrease energy consumption and scale up the nominal size. Ammonia shipping as cargo is already done on a commercial scale. However, its use as a fuel for shipping requires further de-risking, with the first ammonia engines expected to be available by 2024. LOHC (de)hydrogenation is only carried out in the scale of 1.5-5 t/d of hydrogen.
Sources: DNV (2020); Sekkesæter (2019).

The main advantages and disadvantages for each of the pathways is shown in Table 1.1, with a comparison between options in Section 6. In brief:

- Ammonia is already produced, stored and traded on a large scale today. The main limitation is the ammonia reconversion to hydrogen (called cracking), which can consume the equivalent of 13-34% of the energy contained in the hydrogen.[7]
- LOHC have similar properties to diesel and can be transported as a liquid, which translates into low losses during the transport step. The main limitation is the energy consumption of the reconversion (called dehydrogenation), which can consume the equivalent of 25-35% of the energy contained in the hydrogen.
- Liquid hydrogen has the limitations of the energy consumption of liquefaction (at least 25% of the energy in the hydrogen), the need for liquefaction plants to be significantly scaled up from the current levels, the lack of commercial large-scale ships, the expense of making equipment suitable for cryogenic conditions (-253°C) and some technology challenges in the liquefaction step that need to be overcome to increase the maximum scale.

TABLE 1.1. Advantages and disadvantages of each potential hydrogen carrier

CARRIER	ADVANTAGES	DISADVANTAGES
Ammonia	• Already produced on a large scale • Already globally traded • Low transport losses • High energy density and hydrogen content • Carbon-free carrier • Can be used directly in some applications (e.g. fertilisers, power generation, maritime fuel) • Can be easily liquefied (20°C at 7.5 bar or -33°C at 1 bar)	• High (12-26%) energy consumption for ammonia synthesis • High (13-34%) energy consumption for reconversion (importing region) with high temperature requirement (up to 900°C but more commonly in the 500-550°C range) • Ship engines using ammonia as fuel need to be demonstrated • Might require further purification of the hydrogen produced • Hydrogen compression needed for most applications • Higher NO_x (nitrogen oxides) production during shipping would require flue gas treatment • Toxic and corrosive • Flexibility of the ammonia synthesis and cracking still to be proven
Liquid hydrogen	• Limited energy consumption for regasification (most of the energy is consumed in the exporting region, which is expected to have low renewable energy costs) • No need for a purification system at the destination • Easier transport at the importing terminal • Low energy consumption to increase pressure of hydrogen delivered • Liquefaction is already a commercial technology • Carbon-free carrier	• High energy losses for liquefaction (30-36% today), which calls for larger energy supply • Boil-off (0.05-0.25% per day) during shipping and storage • Cryogenic temperatures lead to high equipment cost • Currently available only on a small scale

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[7] Hydrogen could be used to obtain the high-temperature heat, but it could also be provided by a local energy supply.

TABLE 1.1. (Continued)

CARRIER	ADVANTAGES	DISADVANTAGES
LOHC	• Can be transported as oil is today using existing infrastructure, making it suitable for multi-modal transport • Low capital cost for all steps • Can be easily stored	• High (25-35%) energy consumption for dehydrogenation (importing region) • Requires high-temperature heat (150-400°C) for dehydrogenation • Requires further purification of the hydrogen produced • Hydrogen is produced at 1 bar, requiring compression • Only 4-7% of the weight of the carrier is hydrogen • No clear chemical compound that is the most attractive • All the possible carriers currently have a high cost • Carrier losses every cycle (0.1% per cycle) • Carriers would probably contain fossil CO_2 • Most of the possible carriers require scaling up multiple times from current global production
Pipelines	• Transport and storage are proven at a commercial scale • Existing network can be repurposed to hydrogen • No conversion is required (only compression) • Carbon-free carrier • Becomes more attractive as the volume increases	• Storage in specific types of reservoirs can lead to losses and contamination (need for purification) • Not all the pipeline materials are suitable for hydrogen • Not all regions have an existing gas network • Cost increases significantly for offshore pipelines • Energy consumption for transport is higher than for natural gas or ships

The following sections address each of the steps and pathways in Figure 1.3 in detail. For each, the approach was to collect all the relevant literature on techno-economic parameters, and then to define a value range to capture the uncertainty in the data and in the technology development potential towards 2050. Thus, for almost every technology parameter *Optimistic* and *Pessimistic* values are defined, which represent the performance that leads to the lowest and highest hydrogen cost respectively. These costs are representative global averages, although there will still be regional variations due to localised labour, installation, engineering and other related costs. While the costs considered in this report follow a continuous decrease as global capacity increases, there might be periods of higher costs due to installation rates that run ahead of the manufacturing supply chain (e.g. shortage of labour or materials) or due to commodity price fluctuations caused by short-term capital flows.

2

AMMONIA

AMMONIA

Highlights

Ammonia is already produced on a large scale, is globally traded (about 10% of global production) and stored, and has existing infrastructure in over 120 ports that could be used for trade. Ammonia can also be directly used as an industrial feedstock and maritime fuel, and for power generation. One challenge for its use as a maritime fuel is that technological advances in internal combustion engines are needed. Engine manufacturers aim to have the technology ready by 2024. Regulatory changes are also needed to allow ships that carry ammonia to use their own cargo as a fuel. Ammonia is toxic and corrosive, but there are already established practices for safe handling from experience in the chemical industry.

A challenge for ammonia use as a hydrogen carrier is the heat supply needed for cracking, which is critical for economic and environmental performance. This corresponds to losses of at least 15% (and up to 33%) in the reconversion step. The necessary temperature level is relatively high (500-550°C), which makes electrification more challenging and discounts waste heat as an alternative. Instead part of the transported hydrogen could be used to provide the heat (decreasing the overall process efficiency). Alternatively, domestic energy could be used, but this would have a high cost since it is required in the importing country, which is assumed to have high energy costs (increasing the delivered cost). Or another renewable energy (e.g. bioenergy) could be used. Cracking might not be needed if the ammonia is used directly, which would be the case for industrial feedstock, fuel for international shipping or even power generation. Beyond cracking, another area that needs further research is the flexibility of the synthesis plants that convert hydrogen to ammonia.

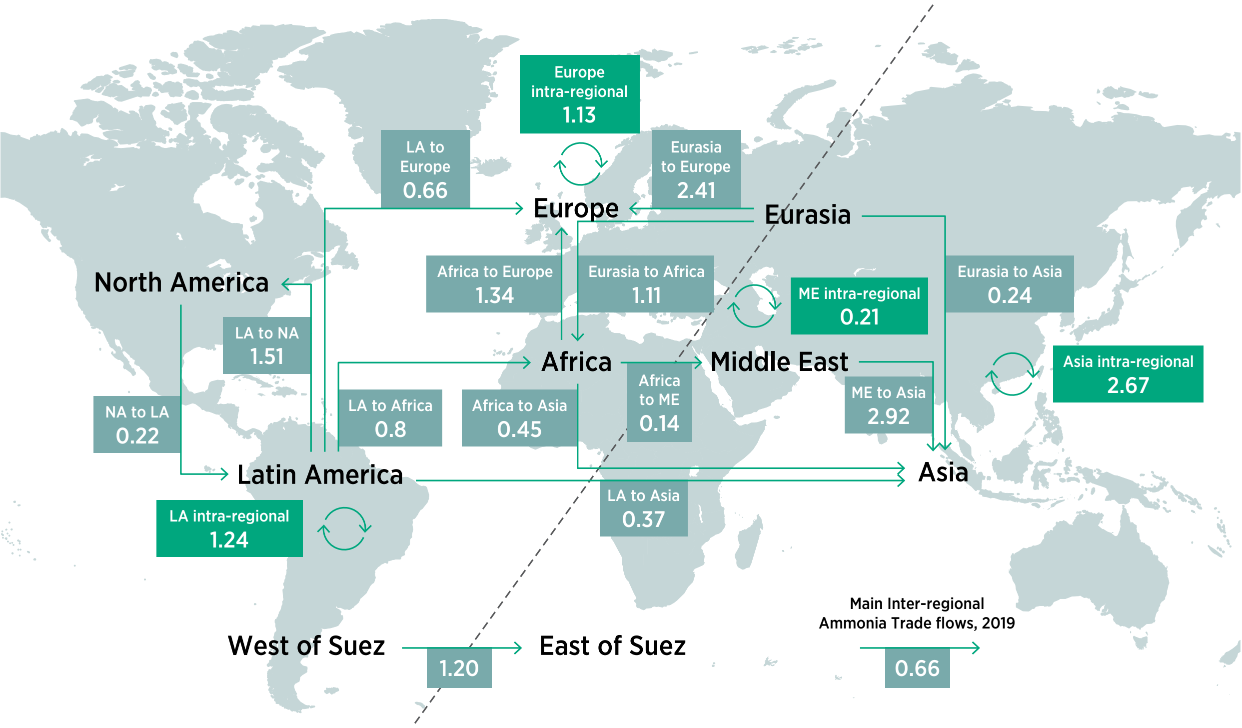
Currently ammonia is mostly produced from natural gas and coal. The renewable pathway needs to be demonstrated on a large scale and there is a capacity pipeline of about 34 Mt/yr for the next decade (vs 183 Mt/yr of current production), with 50% of this located in Latin America. The total project pipeline (including projects without a start-up date) is almost 100 Mt/yr, with almost half in Australia.

2.1 Technology status

Ammonia is already produced on a large scale. Global ammonia production was about 183 Mt in 2020, requiring almost 32.4 MtH_2.[8] A quarter was produced in China and another 30% in Russia, the United States and India (UCGS, 2021). Of the total ammonia produced, 72% is from natural gas, 22% from coal, 5% from oil and less than 1% from renewables (IRENA and AEA, 2022). The CO_2 emissions associated with this production are 300 $MtCO_2$ from the use of fossil fuels for energy purposes and 270 $MtCO_2$ from the feedstock (of which 140 $MtCO_2$ are captured and used for urea and then released into the atmosphere when urea is used in agriculture) (IEA, 2021). Currently 10% of production is globally traded, using pipelines and more than 70 LPG tankers with cargo capacities from 2 500 t to 40 000 t (Topsoe, 2020). The largest flows in 2019 were from the Middle East to Asia (2.9 Mt), intra-regional trade in Asia (2.7 Mt), and Eurasia to Europe (2.4 Mt). The largest exporting region was Eurasia (3.8 Mt) and the largest importing region was Europe (4.4 Mt).

Some regions that are expected to play a prominent role in future green hydrogen exports do not have a hydrogen exporting role today. Australia exported only about 0.2 Mt of ammonia in 2018, Africa is a net importer of ammonia, and exports from Latin America are relatively modest (see Figure 2.1). Most of the current ammonia trade is interregional, with the largest flows being to neighbouring regions rather than across the globe (Eurasia to Europe, Middle East to Asia and Latin America to North America).

FIGURE 2.1. Global trade flows of ammonia in 2019 (Mt)



Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city, or area or of its authorities, or concerning the delimitation of frontiers or boundaries.
Source: (Topsoe, 2020).
Note: LA: Latin America; NA: North America; ME: Middle East.

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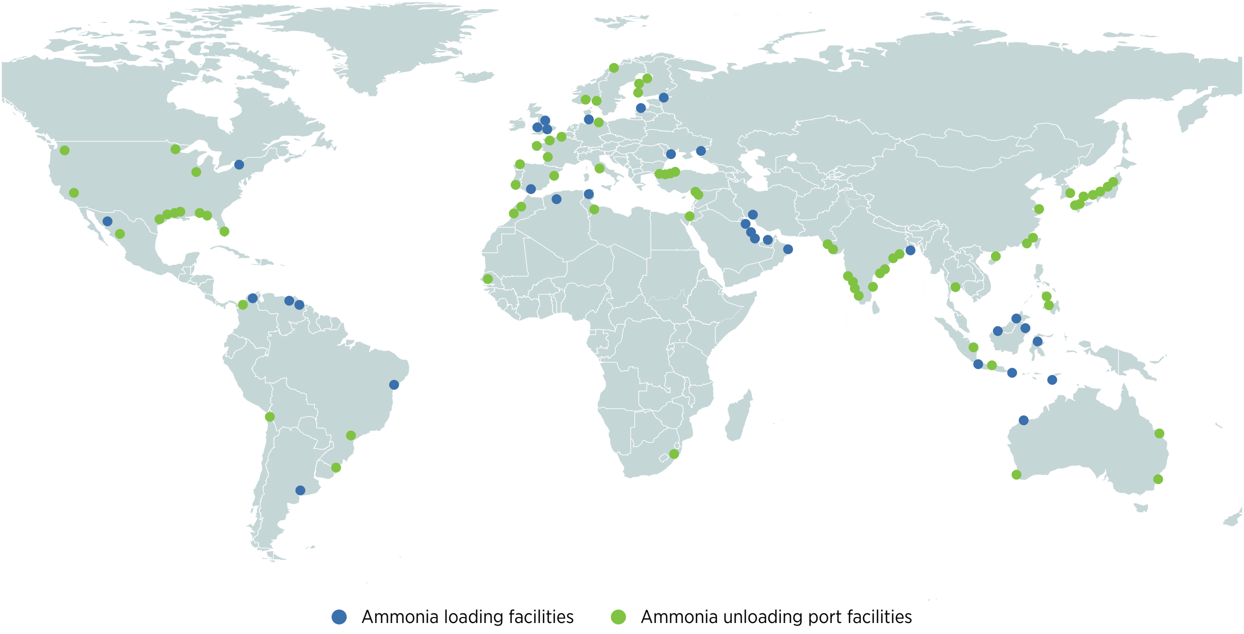
[8] All the ammonia is produced from hydrogen and what makes it sustainable or not is the pathway used to produce the hydrogen.

Given this global trade, there is already significant infrastructure that could be used as a basis for further ammonia trade as a hydrogen carrier. Ammonia terminals are present at 38 ports that export ammonia and 88 ports that import ammonia, including 6 ports that both export and import ammonia (see Figure 2.2). The terminals have filling and discharging systems and also have storage facilities, which are in some cases shared with ammonia or fertiliser plants that are close to the port. There are two main types of storage tanks: isothermal tanks (up to 45 000 t) and spherical pressure tanks (1 000-2 000 t) (Rouwenhorst et al., 2019). The ports with a high cargo throughput and existing ammonia facilities are those with the highest prospects of being frontrunners in handling ammonia as a hydrogen carrier, not necessarily because of the cost savings (which are small compared to the entire value chain), but because of their familiarity and experience with the compound. For instance, the Port of Rotterdam has signed a memorandum of understanding (MoU) with a corporate alliance (Transhydrogen Alliance) to import green ammonia (and green hydrogen) into Europe via Rotterdam. The project could be operational by 2024, building up to a long-term import capacity of 0.5 MtH_2/yr (equivalent to 3.8 Mt/yr of ammonia).[9] Similarly, the Port of Onahama (Japan) is examining the changes needed to potentially import up to 1.6 Mt/yr of ammonia. Others, like the Port of Singapore, are exploring the use of ammonia as a fuel for ships, which could have synergies with the use of ammonia as a hydrogen carrier.

FIGURE 2.2. Ports with loading and unloading facilities for ammonia



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Source: Rodrigue (2020).

Ammonia facilities are also located inland. The United States has 3 060 km of pipeline (from Texas to Iowa) and a pipeline from Russia to Ukraine is 2 420 km long, transporting ammonia for use in fertiliser and chemical plants (Valera-Medina, 2020). These are small-diameter pipelines of less than 35 cm compared to oil and gas pipelines, which can reach 122 cm. There are also multiple ammonia storage facilities around the world. For example, the United States has over 10 000 ammonia storage facilities.

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[9] Assuming a 75% reconversion efficiency.

Therefore, the conversion and transport steps are already carried out on a large scale, and the infrastructure exists to facilitate the adoption of ammonia as a hydrogen carrier. The main steps that need further development are the use of ammonia as a fuel for the ships (it is currently transported as a cargo, the ships using fossil fuels) and the reconversion from ammonia to hydrogen (cracking, if needed).

2.2 Project pipeline

Production

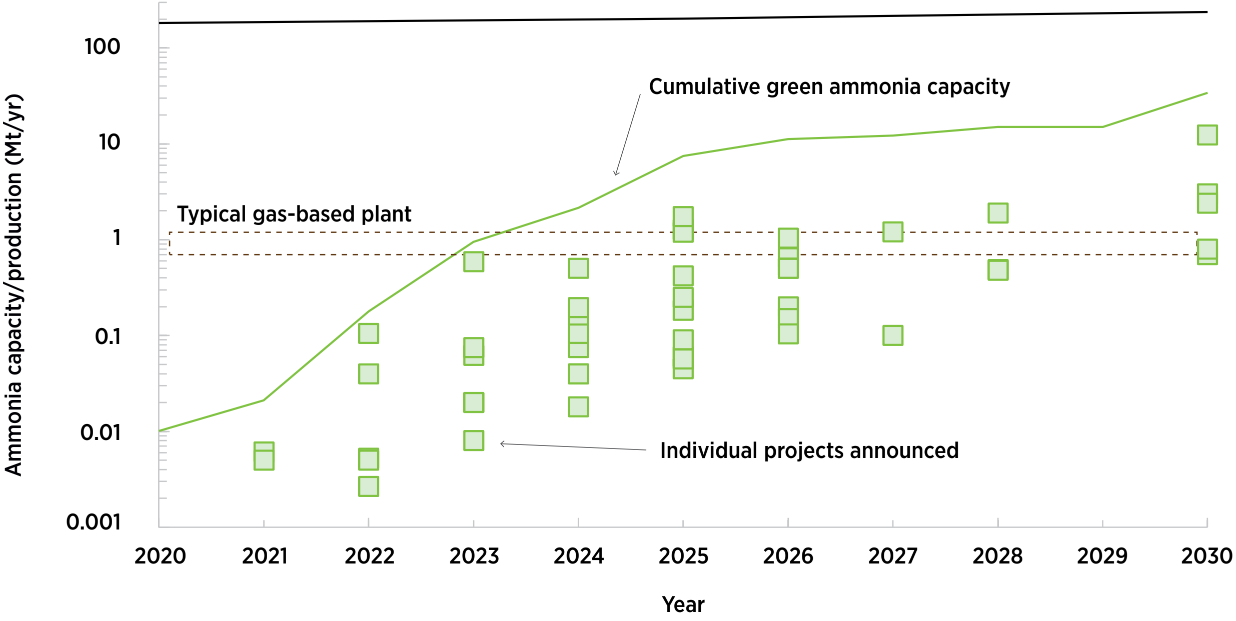
As of December 2021, green ammonia projects that have been announced add up to a cumulative capacity of 34 Mt/yr within the next decade (see Figure 2.3), with 50% of this located in Latin America. The total project pipeline (including projects without a start-up date) is almost 100 Mt/yr, with almost half in Australia (IRENA and AEA, 2022). The largest project is the Western Green Energy Hub in Australia, which has a target of 50 GW of renewable capacity (30 GW of wind and 20 GW of PV) to produce 3.5 MtH_2/yr or 20 Mt/yr of ammonia. The companies involved are CWP and Intercontinental Energy, and the project requires total investment of AUD 70 billion. The final investment decision is expected by 2028, with initial production from the first of three phases in 2030. The other large project in Australia is the Asian Renewable Energy Hub, proposing 10 Mt/yr of ammonia capacity (for export to Japan or South Korea). It included 26 GW of renewable capacity and 14 GW of electrolyser capacity, representing USD 36 billion of investment. The final investment decision was due to take place in 2025, with exports beginning in 2028. However, the project was rejected by the federal government, and the Clean Energy Council is looking for clarification of the basis for the rejection. Other large projects in Australia are:

- 2.4 Mt/yr in Carnarvon from onshore wind and PV, by 2030 or earlier.
- 1.9 Mt/yr in Murchison from onshore wind and PV, by 2028 (decision between ammonia and liquid hydrogen is still pending).
- 1.8 Mt/yr in Gladstone from PV, the first phase starting in 2025 (by Hydrogen Utility using 3 GW of electrolyser in total).

Outside Australia, Green Energy Oman is one of the largest projects, which has a target to produce 10 Mt/yr of green ammonia from 25 GW of renewable capacity. The project partners are the national oil company in Oman, Enertech (a renewables development company) and Intercontinental Energy. The estimated investment is USD 30 billion, with a targeted final investment decision by 2026. Another large project is Aman in Mauritania, which aims to produce 10 Mt/yr of green ammonia from 30 GW of wind and solar PV. It expects to complete the feasibility studies in 2022 and has an ultimate start date for operation before 2030 (CWP, 2021). In November 2021 the Namibian government awarded a tender to construct a plant with 5 GW of renewables and 3 GW of electrolysis with a total expected investment of USD 9.4 billion. First production is expected by 2026 with an initial capacity of 2 GW of renewables. The Helios project (Saudi Arabia) envisages 4 GW of renewable capacity powering 2 GW of electrolyser to produce 1.2 Mt/yr of ammonia. The total investment foreseen is USD 5 billion and the project is planning to start operations in 2025. The contract to supply the electrolysers was signed in December 2021. Fortescue is also looking to expand hydropower in the Democratic Republic of Congo as part of the Grand Inga project, with investment of up to USD 80 billion for hydropower capacity of 42 GW that will also be used for hydrogen and ammonia production. The first phase is expected to be the Inga 3 project with 4.8 GW capacity.

Most of the announced projects focus on ammonia production and for most reconversion to hydrogen is not part of the scope or it is not clear. For a detailed list of green ammonia projects, refer to IRENA and AEA (2022).

FIGURE 2.3. Projected green ammonia capacity according to project announcements



Notes: The green squares represent the capacity of planned green ammonia projects. For each project, the planned start year is used. The solid green line is the cumulative capacity of these projects over time. The solid black line represents projected global ammonia production. The dotted brown line represents a world-scale natural gas-based ammonia plant producing about 0.7-1.2 Mt ammonia annually.
Source: (IRENA & AEA, 2022).

Shipping

One project already demonstrating global trade (on a small scale) is a joint Saudi Aramco, Institute of Energy and Economics in Japan (IEEJ) and SABIC project, with the support of METI. In September 2020 it demonstrated the shipment of 40 t of natural gas-based ammonia from Saudi Arabia to Japan for use in power generation. Ammonia production included CO_2 capture, which was used for methanol production (30 t of CO_2) and enhanced oil recovery (20 t of CO_2) (IEEJ, 2020).

Equinor has contracted Eidesvik Offshore (under the ShipFC project) to retrofit a ship with a 2 MW solid oxide fuel cell capable of using ammonia. Ammonia is expected to cover 60-70% of the power needs of the ship for one year, starting in 2024. A network of six Scandinavian companies,[10] consisting mainly of cargo owners, is exploring the use of ammonia for their freight network. They expect to place orders in 2022 with deliveries starting in 2024-2025 (Maritime Executive, 2021). The NYK Group is also developing a concept design for an ammonia-ready LNG-fuelled vessel, which would allow the transition from LNG to ammonia once the fuel supply becomes available. The results of the development were due to be ready by January 2022, but no public announcement has been made. Fortescue is planning to convert its existing fleet (eight 260 000 t iron ore carriers) to run on green ammonia, contributing to their goal of achieving net zero emissions by 2040. The first ship is expected to be upgraded to run almost totally on green ammonia by the end of 2022. Fortescue also plans to work on the supply side of the fuel with its 15 MtH_2/yr production target by 2030.

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[10] Biomar, Elkem, Franzefoss Minerals, Saltimport, Vestkorn, and Viridis Bulk Carrier.

Bunkering

For bunkering, the Maritime and Port Authority of Singapore (MPA), together with Maersk and another five parties, are carrying out a feasibility study to establish green ammonia ship-to-ship bunkering at the Port of Singapore (the second largest port in the world) (Crolius, 2021). The Port of Rotterdam is also exploring different maritime fuels and their bunkering requirements. In 2021 an alliance of 45 organisations led by the Port of Rotterdam Authority received EUR 25 million from the European Commission to explore the use of multiple fuels to decarbonise port operations (Port of Rotterdam, 2021).

Reconversion

With regard to ammonia reconversion to hydrogen, the "Green Wilhelmshaven" project has an ammonia cracker in its scope and is due to be connected to a German hydrogen network. The project scope also includes a 410 MW electrolyser expected to produce 0.3 MtH_2/yr. The Campfire project will investigate the use of ammonia as a hydrogen carrier, including the cracking step. This is part of the TransHyDE project in Germany funded by the Federal Ministry of Education and Research (BMBF) as a follow-up to the hydrogen strategy.

The range of companies involved in these projects is wide, but Yara, Proton Ventures, ThyssenKrupp, CWP Global, Intercontinental Energy, H2U and Haldor Topsøe are among the most active.

2.3 Conversion (ammonia synthesis)

How ammonia can be produced

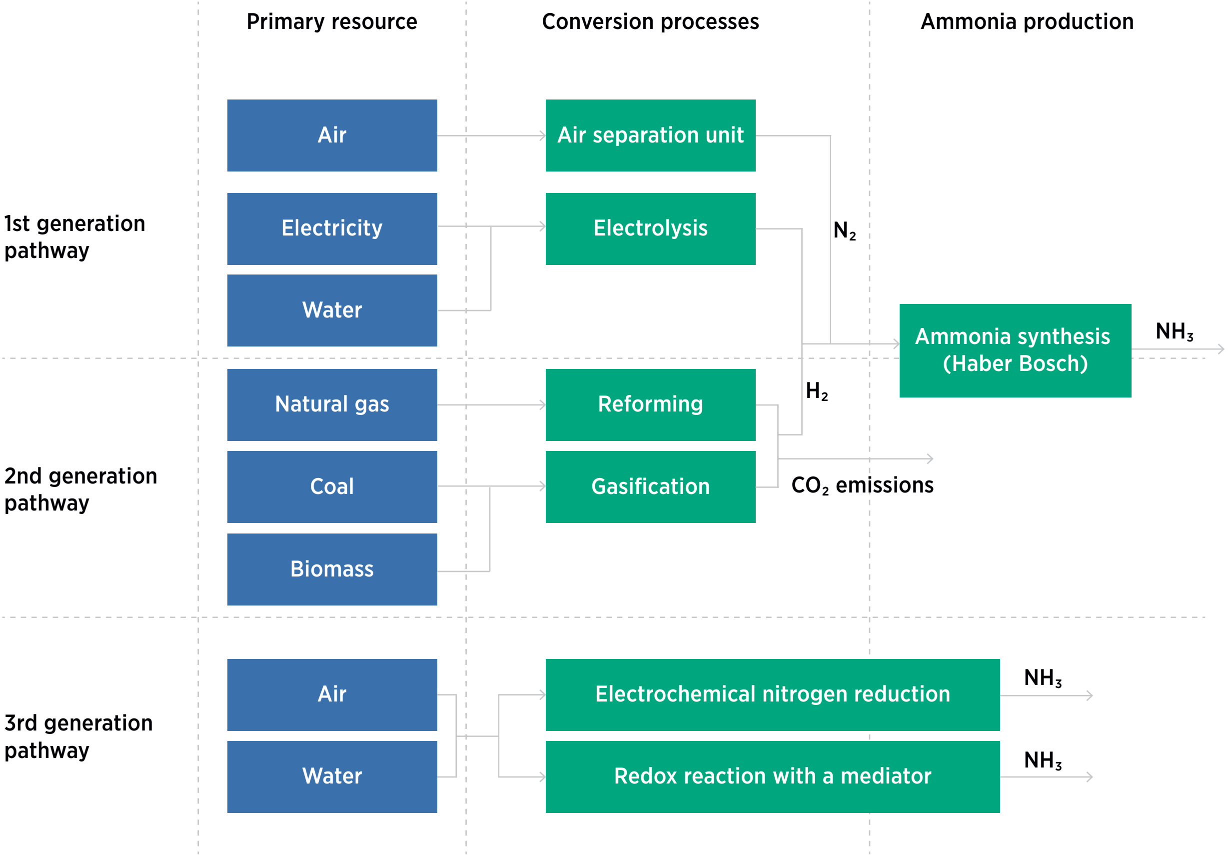
Ammonia is commercially produced today through the Haber-Bosch process by combining hydrogen and nitrogen at high temperature (400-650°C) and pressure (200-400 bar) (Salmon and Bañares-Alcántara, 2021). This process was developed in the early 20th century by German scientists, the first industrial plant being built in 1913 by BASF in Oppau, Germany. The conventional process involves two steps: forming gas production (a mixture of hydrogen and nitrogen) and ammonia synthesis (from forming gas to ammonia). Forming gas can be obtained by combining hydrogen from electrolysis with nitrogen from the air (first-generation pathway), and by reforming natural gas or gasifying coal or biomass to produce hydrogen, which can then be combined with nitrogen from the air (second-generation pathway) (MacFarlane et al., 2020). Nitrogen from the air can also be directly converted to ammonia without the need to produce forming gas or using the Haber-Bosch process (third-generation pathway).

Ammonia production initially relied on electrolysis (mostly coupled with hydropower), transitioning to natural gas in the 1960s and 1970s with the wider availability of gas and low-cost hydrogen from steam reforming. The largest electrolysis plants were built in the 1940s in Europe after World War II and later in the rest of the world, with the largest plant reaching a size of 162 MW (Krishnan et al., 2020). By 1998 only seven hydroelectric ammonia facilities were still active in the world, accounting for 0.5% of the total worldwide ammonia production (Morgan, 2013). By end of 2021 only one was left, in Cusco, Peru.

Ammonia production based on natural gas or coal, the dominant pathway today, only changes the process used to produce the hydrogen. It does not change the synthesis step or the separation process for producing the nitrogen (from the air) (see Figure 2.4). This pathway already involves carbon capture as part of the process regardless of its successive use or storage. Today, about half of the captured CO_2 is used for urea production, which is usually co-located with the ammonia production.

Ammonia can also be produced directly from air and water. This can be done through an electrochemical nitrogen reduction reaction or through a series of reduction and oxidation reactions. These pathways have already been explored by the Department of Energy in the United States as part of the REFUEL program, which is targeting 60% efficiency (from electricity to ammonia) – higher than the electrolytic pathway. Given the electrochemical nature of the process, it would also be able to quickly ramp up and down according to the electricity input (MacFarlane et al., 2020). A disadvantage of the direct electricity to ammonia route is that it has a low TRL and still needs further research to reach a commercial scale.

FIGURE 2.4. Primary resources and conversion steps in various generations of ammonia production technologies

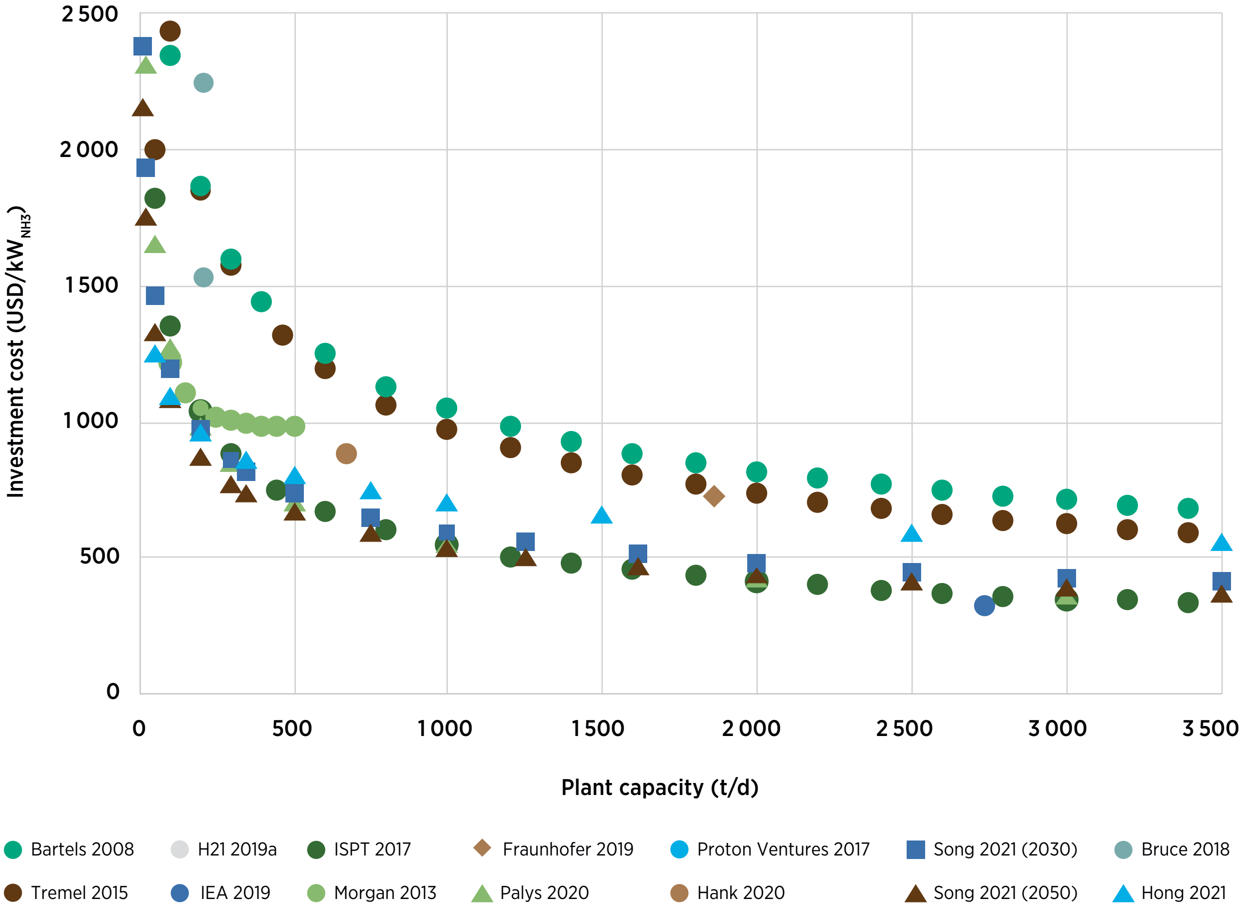


Cost of ammonia synthesis

Two main parameters are relevant for comparing the alternative approaches to trading hydrogen: cost and efficiency. The cost in turn is composed of three parameters: capital cost (capital expenditure or CAPEX), fixed operating cost and energy cost. The efficiency comprises the thermodynamic efficiency losses during conversion and the energy consumption of the process.

Air separation and ammonia synthesis are already mature technologies that are expected to offer limited learning by further deployment. The main parameter affecting the CAPEX of these units is the plant scale. Maximum plant scale has evolved from 900 t/d in the 1960s to 3 300 t/d by 2018 (Brightling, 2018). Haldor Topsøe has announced plans to build a 3 500 t/d plant and Thyssenkrupp already has a 3 760 t/d plant operating in Saudi Arabia. These are conventional plants that use steam methane reformers. If a different technology is used (autothermal reforming), plants of 4 000-6 000 t/d are possible (Valera-Medina, 2020). Considering the scale of current plants, the capital cost of the synthesis and conditioning steps can be in the order of USD 340-680/kW_{NH3} (see Figure 2.5). This could potentially decrease further to USD 290-580/kW_{NH3} if larger scales (5 000 t/d) are considered. This range is the one used for the *Optimistic* and *Pessimistic* technology scenarios. To put the capacity into perspective, a single 5 000 t/d plant would require an electrolyser of 2.7 GW (assuming 4 000 full load operating hours) to produce the equivalent hydrogen that 3.75 million fuel cell electric vehicles (FCEVs) would consume.

FIGURE 2.5. CAPEX for ammonia synthesis and auxiliary equipment



Note: Cost is expressed in terms of the synthesis output (1 kW of ammonia produced).
Sources: Bartels (2008); Bruce (2018); Fraunhofer ISI (2019); H21 (2019a); Hank et al. (2020); Hong (2021); IEA (2019a); ISPT (2017); Morgan (2013); Palys and Daoutidis, (2020); Proton Ventures (2017); Song et al. (2021); Tremel et al. (2015).

The lower costs driven by economies of scale apply to conventional plants. If the design is changed, low cost at small scale could also be possible. This can be achieved by using modular units with a standard design that are multiplied depending on the project scale. The cost advantages are that the engineering in each project is limited since it is the same design used multiple times, the work on site is also reduced since the plant comes in prefabricated modules, and construction is also simpler given the assembly of skids. The small scale also allows for the use of pressure swing adsorption (PSA), which does not require cryogenic temperatures, as opposed to an air separation unit. A trade-off for the lower air separation cost is that PSA leaves argon as a contaminant in the nitrogen stream, requiring a larger purge stream in the synthesis loop, increasing losses.

A modular approach to the plant can result in up to 25% lower CAPEX (Sievers et al., 2017). This small scale is the direction some vendors are going, such as Proton Ventures. There are also examples of demonstration projects for small-scale operation. One is in operation at the Rutherford Appleton Laboratory in Oxfordshire (United Kingdom) and another is a 20 kg/d project in Fukushima (Japan), which has been designed to test the cycle stability of different catalysts (Royal Society, 2020). However, given the production magnitude expected to be needed to achieve global trading, large-scale ammonia synthesis is preferred.

The fixed operational expenditure (OPEX) is usually estimated as a fraction of the CAPEX. This fraction ranges from 1.5% (IEA, 2019a) to 2% (Ikäheimo et al., 2018), 2.5% (Sekkesæter, 2019) and 4% (H21, 2019a). Based on this input, the assumed *Optimistic* and *Pessimistic* values are 2% and 4% respectively.

Energy consumption for ammonia synthesis

The other main parameter is the energy consumption. Energy is consumed in the air separation unit (electricity), refrigeration compressor, feed compressor, recycle compressor and heater. Under regular operating conditions, the conversion in the ammonia reactor is not complete and part of the hydrogen in the outlet needs to be separated from the ammonia product (by condensation) and recycled to the inlet to increase the overall conversion. With this recycle, almost all (97-99%) of the hydrogen is converted to ammonia and the only losses are through heat since the reaction is exothermic (meaning it releases heat). The heat losses are equivalent to about 8% of the energy contained in the ammonia and can be used to preheat the feed and operate the reactor autothermally.

The electricity demand of an air separation unit (ASU) largely depends on the plant size and the degree of refrigeration recovery, leading to a range of 0.5-0.8 kWh_{el} per kgN_2 (Cesaro et al., 2021). The energy consumption per component is shown in Figure 2.6 for various references. Based on these, the *Optimistic* and *Pessimistic* values used for energy consumption are 0.566 $kWh/kgNH_3$ and 0.755 $kWh/kgNH_3$ respectively, besides the heat losses of 14.5% in the reactor[11] (Smith, Hill and Torrente-Murciano, 2020). The minimum theoretical energy consumption of the electrolytic route is 21.3 GJ/tNH_3 (considering the energy content in the ammonia is 18.6 GJ/tNH_3) (Smith, Hill and Torrente-Murciano, 2020). The electrolytic pathway has lower energy consumption than the natural gas-based route mainly due to a higher delivered pressure for hydrogen (assuming pressurised operation for the electrolyser), no need for purge in the synthesis loop and the use of electric motors rather than steam turbines for the compressors (Smith, Hill and Torrente-Murciano, 2020).

These energy losses are relatively small when the entire pathway from electricity to ammonia is considered where the dominant energy consumption is from the electrolyser, equivalent to about 8.76 $kWh/kgNH_3$.

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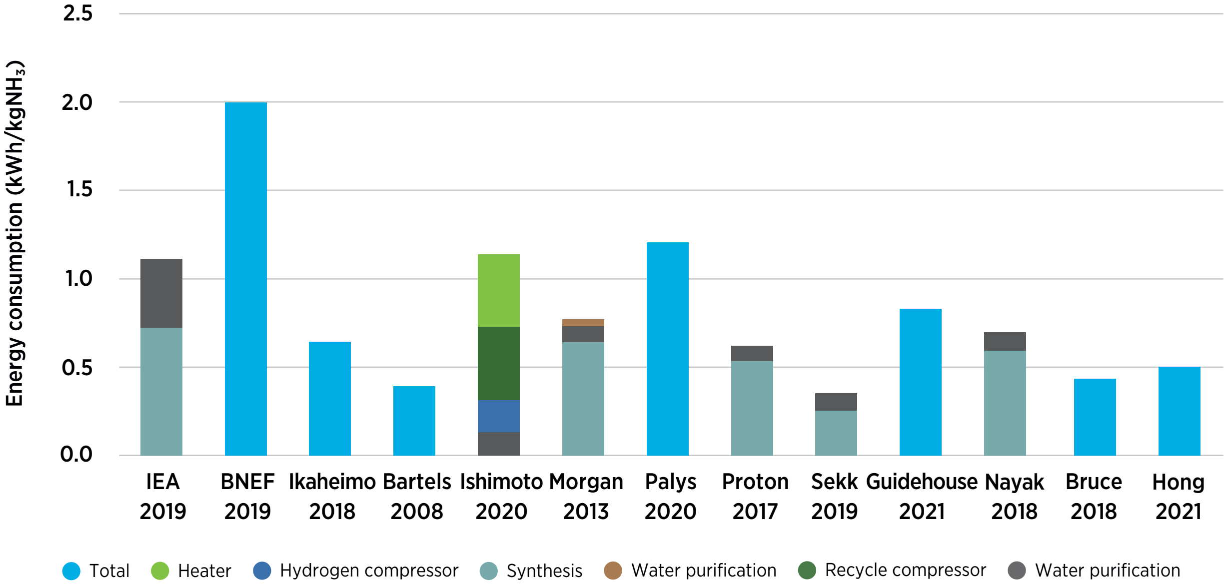
[11] Depending on the process configuration, this heat could be used to preheat the feed or other applications outside the process, such as district heating.

FIGURE 2.6. Energy consumption for ammonia synthesis and auxiliary equipment (excluding hydrogen production)



Sources: Bartels (2008); BNEF (2019); Bruce (2018); Guidehouse (2021a); Hong (2021); IEA (2019a); Ikäheimo et al. (2018); Ishimoto et al. (2020); Morgan (2013); Nayak-Luke, Bañares-Alcántara and Wilkinson (2018); Palys and Daoutidis (2020); Proton Ventures (2017); Sekkesæter (2019).

Alternatives to improve the efficiency of the synthesis loop include first, using absorption instead of condensation for the ammonia separation, second, performing process intensification by integrating the reaction with the separation step, which would not only lead to lower costs but would also remove equilibrium limitations in the reactor, and third, enabling operation at a lower pressure and eliminating the need for a recycle compressor (Smith, Hill and Torrente-Murciano, 2020).

Production flexibility

As the ammonia process shifts from fossil-based to electrolysis-based, the synthesis unit might be exposed to fluctuations in power input from the variability of renewables output. Ammonia synthesis has so far not been operated under these conditions on a large scale, and there is uncertainty about operating limits. The potential effects of flexible operation are shorter catalyst lifetime due to deactivation (Royal Society, 2020) and shorter equipment lifetime due to the thermal cycles (Beerbühl, Fröhling and Schultmann, 2015). One option to prevent this is to have intermediate hydrogen storage, which would allow the use of stored hydrogen for steady-state operation. However, this could be expensive as hydrogen tanks would add anywhere in the range of USD 35-150/tNH_3 to the cost (Ahluwalia et al., n.d.; Armijo and Philibert, 2020; Bañares-Alcantara et al., 2015; Nayak-Luke and Bañares-Alcántara, 2020). This is significant considering fossil-based ammonia costs have fluctuated in the range of USD 200-500/tNH_3 in the last 20 years. This section addresses two aspects: the estimated flexibility of the synthesis reactor; and the design changes that could improve the flexibility of the unit.

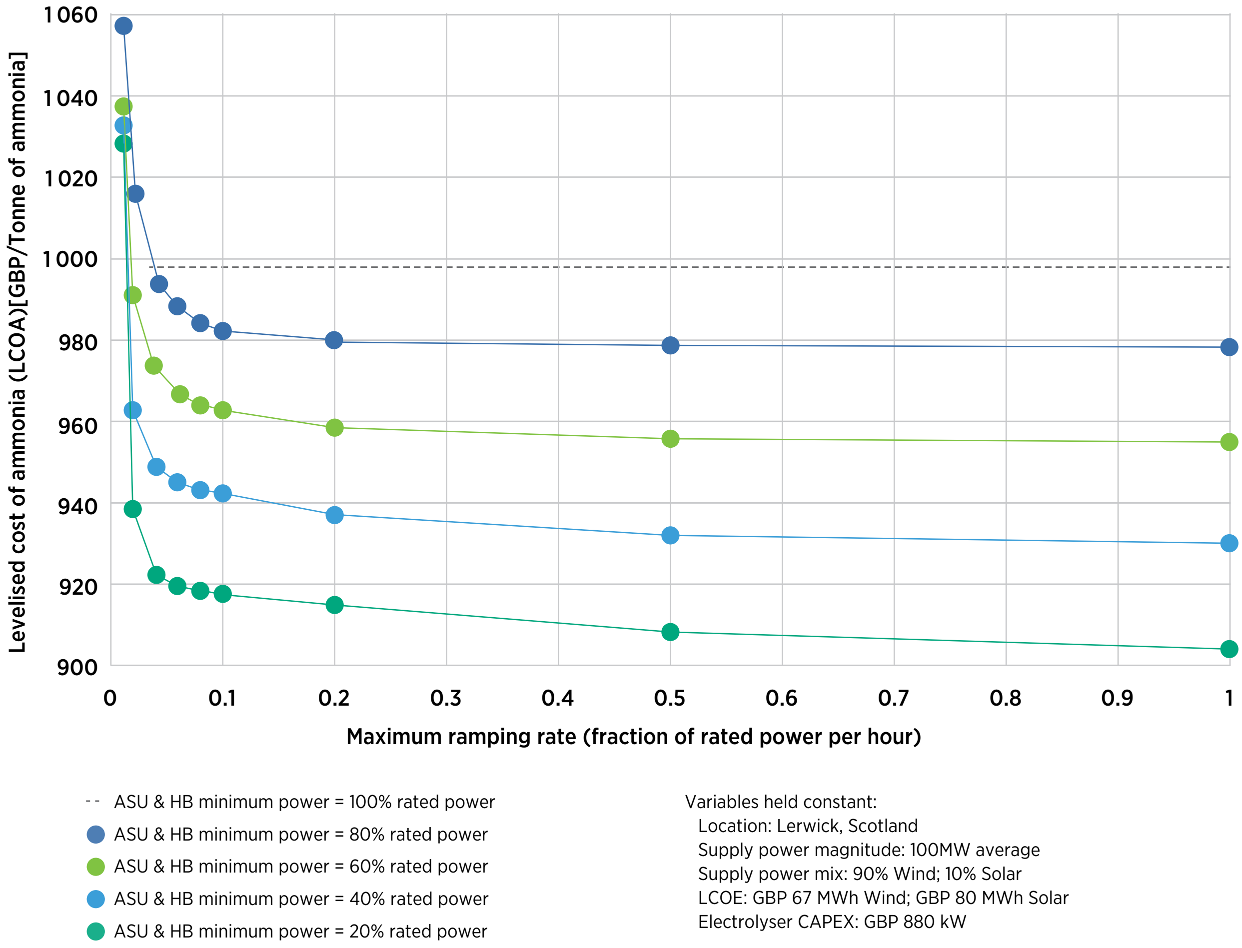
Flexibility of the synthesis reactor

For the flexibility of the reactor, the most important parameters are the ramping rate (i.e. how fast the reactor load can be changed) and the minimum turndown (i.e. minimum stable load the reactor can have). Several studies and references address this aspect:

1. Haldor Topsøe, a technology provider, claims that it is possible to operate the synthesis unit between 10% and 100% without changing the synthesis pressure or using electricity or hydrogen storage (Topsoe, 2020).
2. Fasihi et al. (2021) use a minimum load of 50%, a ramp-up limit of 2% and a ramp-down limit of 20% per hour for the ammonia synthesis unit, coupled with the ASU, without a cost or efficiency penalty. For storage, they consider underground hydrogen storage (salt caverns and rock caverns) operating in a range between 60 and 200 bar, and underground pipeline storage at 20-200 bar. The storage choice affects the hourly ramping rates. The maximum charge or discharge of a salt or rock cavern is limited to 8% per day (0.33% per hour), with the rate roughly doubling for underground pipeline.
3. Beerbühl, Fröhling and Schultmann (2015) considers a load range of 20-100% for the synthesis unit. The minimum load was determined using reactor simulations and also considering the economic impact (further information in Beerbühl et al. [2014] and Ostuni and Zardi [2012] for a similar NH_3 process).
4. Bañares-Alcantara et al. (2015) found that decreasing the operating load to 10% leads to an increase in the energy consumption of the ammonia synthesis loop from 2.2 GJ/tNH_3 to 14.4 GJ/tNH_3. It also states that compressors have a load range of 55-115%.
5. Cheema and Krewer (2018) performed detailed analysis of the operating envelope of the ammonia synthesis process, quantifying the impact of six process variables (reactor pressure, inert gas percentage in the synthesis loop, ammonia concentration, hydrogen to nitrogen ratio, total flow rate and feed temperature). It was found that the parameter with the largest influence was the hydrogen to nitrogen ratio, which enabled a 67% reduction in the hydrogen intake by changing from a 3:1 ratio to a 1.2:2.8 ratio. This was followed by the inert content. Parameters such as operating pressure and temperature had limited impact.
6. Starfire Energy Inc. (2018) achieved a ramping rate of 25% within a minute in an experimental setup with a new process design at low pressure (10 bar), new catalyst preparation and a prototype reactor. Even though very high ramping rates were achieved, it needs further research before being applicable to commercial-scale production, since the dynamics of large equipment are much slower.
7. Proton Ventures, a technology supplier for small-scale plants, has designs for single trains that can be designed to operate at 25-30% of their nominal design capacity.
8. Armijo and Philibert (2020) explored two cases of minimum load, a conservative 60% of the maximum and an advanced flexibility case of up to 20% minimum load. They also explored the possibility of complete stops (i.e. 0%) when the energy outlook is a low load for at least 48 hours (assuming perfect foresight of the renewable input). The minimum load was chosen on the basis of industry interviews and a US patent (Ammonia Casale SA [2016] and Stolten and Scherer [2013, page 694). The ramping rate was assumed to be 20% per hour and a reactor overload of 5% was also considered. They found that the limiting factor for hydrogen storage was the renewable power variation at the seasonal timescale (e.g. a week without wind) rather than the ramping rate.
9. Nayak-Luke, Bañares-Alcántara and Wilkinson (2018) used a minimum load of 20% for the synthesis unit and ASU. They also quantified the cost impact of changing the assumption on minimum load and ramping rate (see Figure 2.7). It showed that the most critical parameter is the minimum turndown, which had an effect of GBP 10/tNH_3 for every 12% difference in the minimum load. A ramping rate of 10% change per hour was enough to achieve most of the benefits of a flexible synthesis unit.

10. ISPT (2017) explored a less conventional route requiring further research, which included a "battolyser" (a combination of a battery and an electrolyser [Mulder et al., 2017]) and a solid-state ammonia synthesis unit. The load range is 0 to 100% with a ramp-up rate of 100% in 40 minutes and ramp-down of 100% in 10 minutes. In the case of high-temperature synthesis with a solid oxide electrolyser, the load range is 50-100% with a ramp-up of 25 minutes and ramp-down of 13 minutes. The limitation for ramping is the ammonia synthesis and the high-temperature electrolysers.

FIGURE 2.7. Levelised cost of ammonia sensitivity to minimum turndown and ramping rate of the synthesis process and air separation unit



Notes: x-axis represents how fast the reactor can change its load and each line represents a different load in comparison to the rated power. ASU = Air Separation Unit; HB = Haber-Bosch.
Source: Nayak-Luke, Bañares-Alcántara and Wilkinson (2018).

Design changes to improve the flexibility of the unit

Two types of measure can be used to improve the flexibility of the ammonia process: changes in process design; and different control strategies. Measures in the first category are (Beerbühl et al., 2014):

- Abandon energy efficiency measures found in the state-of-the-art design, the economic efficiency of which deteriorates with lower annual utilisation (for example, a multi-stage steam system). This makes the process leaner and therefore easier to control.

- Change the ammonia condensation system from the current refrigeration to water cooling. This would require increasing the operating pressure of the reactor to 400-500 bar.
- Use a multi-bed reactor instead of two or three separate reactors. This might favour the cost (due to lower equipment count) and the controllability of the temperature upon load changes.
- Replace a multi-stage, steam-driven turbo compressor that is usually used for syngas with piston compressors, which are easier and faster to control.
- Conduct synthesis at lower operating pressure, which might improve controllability with the downside of not being thermodynamically favoured.

Three control strategies can be used to vary the load (Rouwenhorst et al., 2019):

- Varying the pressure of the synthesis loop, which allows the inventory in the equipment to be varied, effectively acting as storage or buffer. This can be done by regulating the power of the recycling and syngas compressors. One limitation is that this might not be feasible due to mechanical fatigue of the equipment due to cycling.
- Adopting loop parallelisation by varying the ammonia production capacity by opening or closing parts of the equipment. This measure is a combination of process design, since it can imply changing the equipment size to allow for parallel operation, and process control, since changes in load would lead to rapid changes in the amount of equipment that is operating at a certain point in time. A limitation is that this can result in higher capital cost (due to lower economies of scale) and the need for an advanced process control strategy. Large, gigawatt-scale projects will most likely have multiple ammonia synthesis loops in parallel and are likely to use loop parallelisation as a strategy to schedule ammonia synthesis.
- Increasing the inert content in the loop to decrease the reaction rate and ammonia production. The inert content can be manipulated by changing the purge stream before the recycling. Increasing the inert fraction to operate at 10% load (with up to 50% inert) leads to an increase in energy consumption of 10-15% (due to higher compression power). This control strategy has been patented by the ammonia licensor Casale (Ammonia Casale SA, 2016) and is the principle behind earlier patents (Gaines, 1981).

Some of these changes require a better understanding of the effects that pressure, temperature and flow fluctuations can have on catalyst performance and production rates (Beerbühl et al., 2014; Cheema and Krewer, 2018). The available models also have to be extended beyond the typical operating conditions to be able to test new operating windows and the potential effect of new control strategies.

2.4 Shipping

Ammonia is already transported via ship, but is not used as a bunker fuel. The main uncertainties for ammonia-fuelled ships are the prime mover, infrastructure and regulation. Ammonia ships could, in theory, use other fuels, but this may compromise their environmental performance (if heavy fuel oil, LNG or another fossil fuel is used). Efforts to fuel ships by ammonia are being driven by the decarbonisation of international shipping rather than for hydrogen trade (Energy Transition Commission, 2020; UMAS, 2021; World Bank, 2021), so is expected to happen even without demand for ammonia as a hydrogen carrier.

Prime mover

Ammonia can be used in turbines, fuel cells and combustion engines. Solid oxide fuel cells (SOFCs) can use NH_3 directly and have a high efficiency (40-60%) (Valera-Medina, 2020), but lack power density and load response capability (Kim et al., 2020), are expensive (> USD 1650/kW), are sensitive to contaminants and are at an early stage of development. To be able to use other types of fuel cell (e.g. proton exchange membrane), pure hydrogen is needed. This means the ammonia would need to be cracked, potentially using heat from the ammonia itself, which would make the entire process less efficient and closer to the efficiency of large two-stroke maritime diesel engines (de Vries, 2019). Fuel cells convert a fuel to electricity and would additionally need an electric motor to convert the electricity to rotational kinetic energy.

Engines are much cheaper (< USD 550/kW) than fuel cells, more robust, and have acceptable power density and load response. Efficiencies can reach over 50% with ammonia (Sekkesæter, 2019). A disadvantage that engines have is higher NO_x (pollutant) emissions. This could be controlled by using a selective catalytic reduction system, which would use the ammonia itself as a reducing agent. MAN ES, the world's largest engine manufacturer, has announced plans to develop a two-stroke engine that can operate on ammonia by 2024, with a retrofit package for existing vessels from 2025 (MAN ES, n.d.). Wärtsilä is aiming for a more ambitious timeline. It has already tested an engine with a 70% ammonia blend and expects to have an engine concept by 2023, with the first retrofit (of an offshore supply vessel) also in 2023 (AEA, 2021) and the commercial design available one year later (Wärtsilä, 2021). The engines are expected to be able to operate as dual fuel (diesel or ammonia), which would facilitate the transition period (e.g. progressive ammonia blending) and provide more operational flexibility.

Ammonia has a low flammability, which means a pilot fuel is needed to ensure full combustion. This could be diesel at an initial stage, and hydrogen (from on-board ammonia cracking) or a biofuel later (Comotti and Frigo, 2015). Given only a fraction of hydrogen is needed, partial cracking is enough, which means a lower energy requirement and the possibility of using high pressures (to avoid compression) even though this limits conversion. For this case of partial conversion, the exhaust gases and the cooling system from the engine can be utilised to supply heat to the cracker, evaporator and the tank heater. This recycled heat would be sufficient, because only a small percentage of hydrogen is required as a pilot fuel.

Regulation

The standards necessary for the use of ammonia as a fuel still need to be developed. The International Maritime Organization (IMO) is the body that sets the standards for maritime safety, security and environmental performance at a global level. Ammonia is a toxic, corrosive substance, with low flammability and a strong odour. Two IMO codes need to be adapted for ammonia. One is the IMO International Gas Carrier (IGC) Code, which regulates gases as a cargo. Ammonia is already included, but the code would need to be amended since it currently prohibits cargoes identified as toxic products from being used as fuel for the carrying ship. For cargo to be used as fuel a minimum level of safety equivalent to natural gas has to be demonstrated (GMF, 2021a). The second code is the International Code of Safety for Ship Using Gases or Other Low-Flashpoint Fuels (IGF Code). Therefore, both codes need to be modified to allow ammonia carriers to use ammonia, while using it in other ships (e.g. container ships) would only require modifying the IGF Code. The ambitious uptake of zero-emission vessels would require the IMO to update these codes by 2024 to enable ammonia use as a fuel (Energy Transition Commission, 2021b).

Acceptance by the IMO is actually the final step in regulatory procedures; other stages of the process are acceptance by the classification societies and national maritime organisations, and compliance with port-specific requirements. Classification societies regulate ship design to ensure the safety of the crew, the ship and the environment. Approval is usually given in two steps. First is an "Approval in Principle" (AiP), which is a preliminary assessment and means the design has the potential to meet the requirements and final approval. Second is "Final Class Approval". Common classification societies are ABS, Bureau Veritas, DNV, Korean Register and Lloyd's Register. In October 2020, Lloyd's Register granted an AiP to Samsung Heavy Industries for an ammonia-fuelled tanker design and another to Daewoo Shipbuilding & Marine Engineering and MAN Energy Solutions for the use of a 23 000 TEU (twenty-foot equivalent unit) ammonia-fuelled container ship expected to be commercial by 2025. Lloyd's Register has also granted an AiP for an ultra-large containership, a bulk carrier and a gas carrier, all fuelled by ammonia. Bureau Veritas granted an AiP to GTT for an LNG tank design that allows it to be used for ammonia. There are also other projects that are at an earlier stage of conceptual study (GMF, 2021b). In September 2021 ABS published guidelines and requirements for the design, construction and survey of ammonia-fuelled vessels (ABS, 2021a).

Other standards that are relevant for ammonia (and hydrogen derivatives) are:

- ISO standard 20519:2017, which complements the IGC Code and covers operational procedures, requirements for the LNG provider and requirements for the LNG facilities, with special attention paid to safety and fuel quality standards.
- ISO standard 18683:2015, which provides guidance on the minimum requirements for the design and operation of the LNG bunkering facility, including competences of the bunkering personnel and functional requirements for the equipment.

In order to enable the accelerated uptake of zero-emission vessels, the classification societies should conduct risk analyses for ammonia rules in 2022, with the safety standards for port bunkering in place by 2023 (Energy Transition Commission, 2021b).

Infrastructure

Existing ammonia terminals and storage facilities can be used as a starting point. However, this is only one component and further co-ordination with the rest of the value chain is needed, namely with fuel producers, technology providers, vessel owners (shipbuilders, engine providers, fuel storage system providers) and cargo owners (Energy Transition Commission, 2020). The bunkering operation for ammonia would be like bunkering other gaseous fuels with the difference that ammonia is toxic and less explosive. These bunkering procedures still need to be developed in parallel with the development of the safety standards (Topsoe, 2020).

Compared to hydrogen, ammonia is much easier to liquefy and contains 1.7 times more hydrogen per unit of volume than liquid hydrogen. Liquid ammonia needs to be pressurised to around 8 bar at ambient temperature[12] or be cooled down to –33°C at ambient pressure; there is also a semi-refrigerated option with a pressure lower than 8 bar. Pressurised storage is usually preferred for low volumes while refrigerated storage is preferred as the scale increases since

[12] In practice, a higher pressure of 16-18 bar is used (Valera-Medina, 2020).

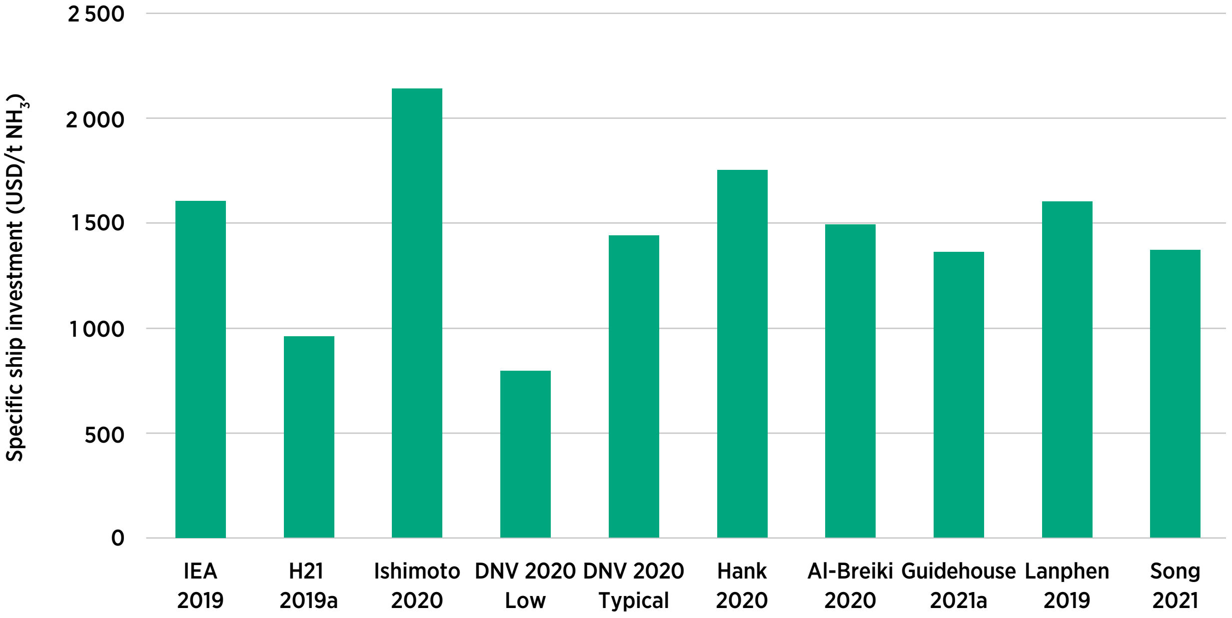
the tanks use less steel and are therefore cheaper (Valera-Medina, 2020).[13] These properties are similar to LPG and that is why LPG carriers can be used to transport ammonia. By the end of 2019 there were over 1100 LPG carriers around the world, which range from 2 500 to 40 000 t in capacity (Topsoe, 2020). There are also already 170 ships in operation that can carry ammonia as cargo and 40 that do so continuously (Brown, 2019). To put this into perspective, almost 100 000 ships were handling international trade by the end 2021 (UNCTAD, 2022). The onboard storage volume required to ship ammonia is about 3.5 times higher than equivalent energy as conventional fossil fuels and about 90% higher than LNG. This may translate into loss of volume available for cargo, but it is usually in the single-digit percentage loss (depending on the type of ship) (Kim et al., 2020).

With respect to the techno-economic performance of transporting ammonia, there are three principal parameters of interest: capital cost, operational cost and efficiency.

Capital cost

For the **capital cost**, the range of values from the literature is shown in Figure 2.8. Ships also exhibit economies of scale, so larger ships tend to have a lower specific cost, but this does not fully explain all the differences in the cost estimates. For instance, H21 (2019a) uses a reference size of 52 000 tNH_3 while Ishimoto et al. (2020) use a 58 000 tNH_3 (85 000 m^3) carrier, still resulting in a factor of 2.2 difference in cost. To capture this uncertainty, the values used for the *Optimistic* and *Pessimistic* scenarios are USD 900/tNH_3 and USD 1 750/tNH_3 for a 60 000 tNH_3 carrier, using a scaling factor of 0.6 to estimate the cost of different sizes (relevant for the early stages of deployment). The dimensions that are required to accommodate a 50 000 tNH_3 ammonia carrier are a channel depth of 11 m, a berth pocket size of 330 m by 53 m, a depth alongside of 12.4 m and a maximum length of 300 m (ARUP, 2019).

FIGURE 2.8. Specific investment cost for an ammonia carrier



Sources: Al-Breiki and Bicer (2020); DNV (2020); Guidehouse (2021a); H21 (2019a); Hank et al. (2020); IEA (2019a); Ishimoto et al. (2020); Lanphen (2019); Song (2021).

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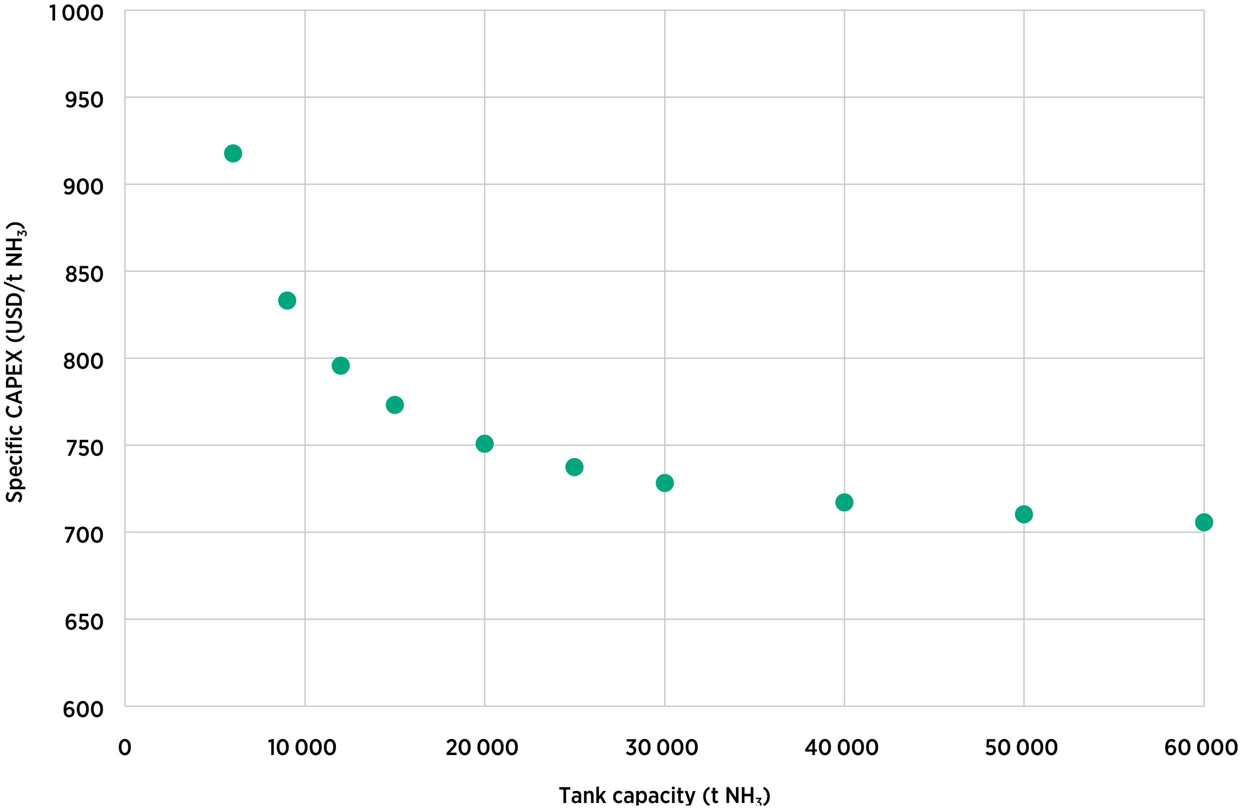
[13] Pressurised storage leads to 1 t of steel per 2.8 t of stored ammonia, while this ratio is 1 t of steel per 45 t of liquid ammonia storage (Valera-Medina, 2020).

Two additional cost items associated with shipping are the cost of the terminal and of storage. For the terminal, Raab, Maier and Dietrich (2021) use USD 118.8 million for a jetty catering for a 225 000 tH_2/yr plant. These costs are assumed to scale linearly with capacity. For storage, cost is also a function of size. The cost trend from Morgan (2013) is used (see Figure 2.9), with a maximum storage size of 60 000 tNH_3. LPG storage tanks have already been constructed with up to 130 000 m^3 capacity, which would be equivalent to almost 90 000 tNH_3 (Siemens, 2020). Boil-off also needs to be considered (0.04%/day for large-scale tanks), which has an additional energy consumption (0.0378 $kWh/kgNH_3$ [LR, 2020]) and requires a re-liquefaction loop consisting of a compressor, flash vessel and a condenser, which are assumed to be included in the cost (small contribution) (Valera-Medina, 2020). Storage is assumed to be needed at both the importing and exporting terminals, and the size is the larger of the equivalent to filling one carrier or a week of plant production (to avoid turnover of the storage volume that is too frequent) (Lanphen, 2019).

FIGURE 2.9. Specific investment cost of an ammonia storage tank



Source: Morgan (2013).

Operational cost

The operational cost includes factors such as crew costs (wages), consumables, insurance, maintenance of the engine, maintenance of the rest of the ship, port fees and transit fees, among others. It also depends on the vessel ownership and contractual arrangement with the operator (see Box 2.1). To simplify these factors, it is assumed that the operational cost will be 2.5% of CAPEX.

Efficiency

There are two main aspects to consider in the use of existing ammonia carriers for global trade. First, these carriers currently use fuel oil, which has more than twice the energy density of liquid ammonia (see Figure 1.2). This means the ammonia fuel tanks will be proportionally larger (see Table 2.1), displacing part of the cargo. For a 2 500 TEU, this can be in the order of 3% (Kim et al., 2020). Second, the cost of ammonia is higher than fossil fuels, increasing the operating costs of the vessel. The cost of VLSFO is about USD 56-60/MWh at a reference oil price of USD 90/bbl and matching these price levels would need electricity cheaper than USD 25/MWh and an electrolyser cost lower than USD 400/kW_{el}. Thus, the cost of ammonia will remain higher than fossil fuel alternatives in the short to medium term.

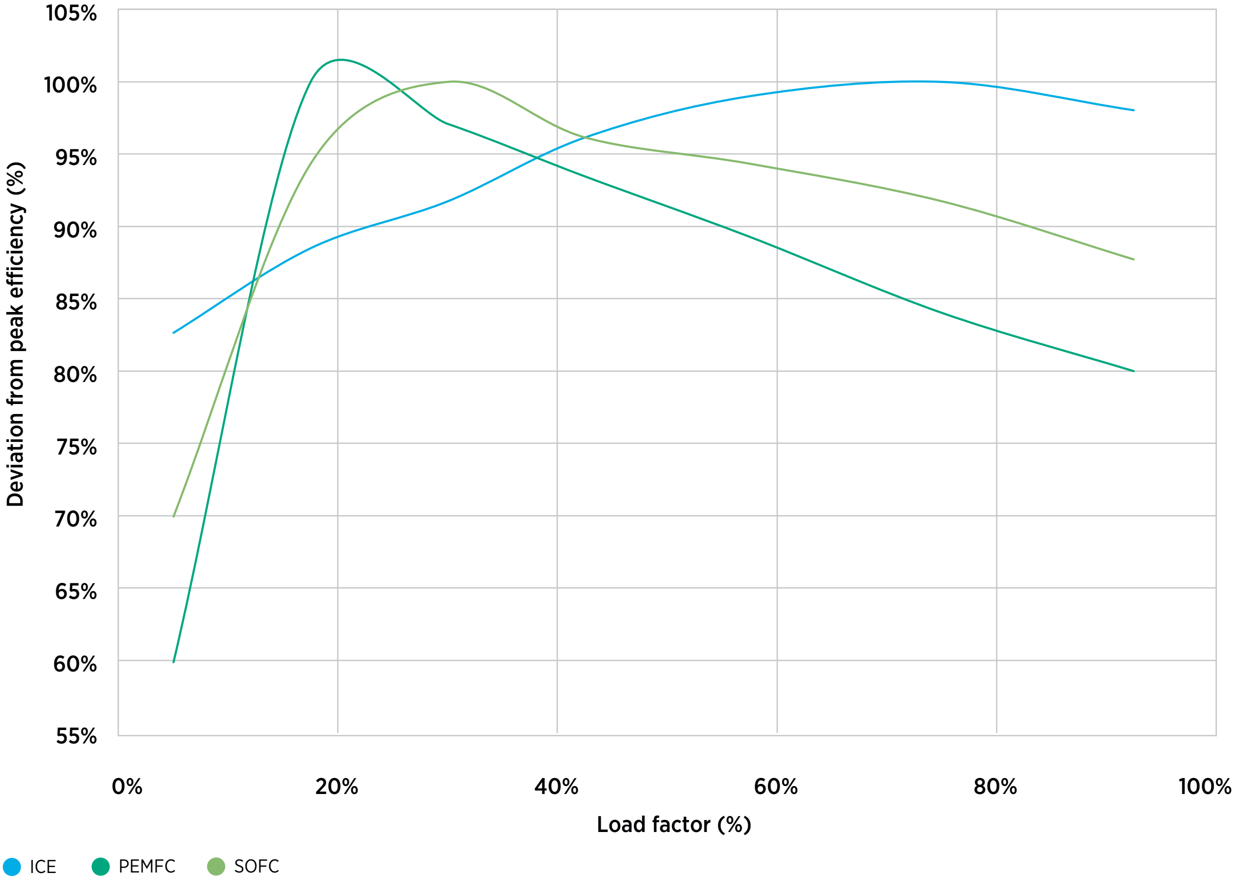
While this is the business case for ammonia as a shipping fuel, the case for ammonia as a hydrogen carrier or feedstock has a different end use with a different benchmark for the reference case. The boundaries for the assessment of ammonia as a fuel are usually the ship and all the associated costs on a total cost of ownership (TCO) basis (IEA, 2019b; Korberg et al., 2021). Instead, the boundaries for ammonia use as a carrier or feedstock are broader and cover the (re) conversion steps and potentially the linkage with another use that has a different willingness to pay (e.g. steel or power generation) in a region that has limited or expensive renewable energy (since it is importing energy). Furthermore, the cost contribution of the transport step within this broader envelope is relatively small (see Section 6.1) for ammonia even with the higher production cost.

The final component is the energy consumption of the ship. This is a function of engine power and vessel speed. The engine power is proportional to the vessels' deadweight tonnage (dwt) and maximum speed. For this study, the engine size is based on LPG vessels from the IMO 3rd GHG report (IMO, 2014). Energy consumption exhibits non-linear behaviour with vessel velocity, so small increases in speed (e.g. to achieve a shorter trip) can have a large impact on energy consumption.

Lastly, the prime mover and the heat recovery system assumed also have an impact on energy consumption. One possibility is to use ammonia directly in gas turbines. For example, Mitsubishi Power is developing a 40 MW gas turbine that can use 100% ammonia with a targeted commercialisation date of around 2025 (MHI, 2021). Another option is to use ammonia in a fuel cell, such as an SOFC. Polymer electrolyte membrane fuel cells (PEMFCs) are not considered, since they are highly sensitive to ammonia poisoning and would require full cracking and a purification system. SOFCs have an efficiency of around 75%, with the 25% losses available as waste heat at a temperature level of 900°C, while a gas turbine releases about 40% of the energy as waste heat at a temperature level of 600°C. On-board cracking, where needed (e.g. to provide a pilot gas), has limited impact on the overall efficiency and could use part of the waste heat from the prime mover.

Fuel cells and internal combustion engines (ICEs) also exhibit different behaviour with partial load. Peak efficiency for fuel cells is reached in the range of 15-30% load compared to the maximum, while for ICEs it is 65-75%. The de-rating for low load is also higher for fuel cells, which lose up to 40% of peak efficiency for loads of less than 10%, while ICEs stay above 80% of their peak efficiency (see Figure 2.10). PEMFCs have higher specific power than ICEs (see Table 2.1), and even considering other items such as the motor drive, converters and cracker, the space occupied by the equipment is smaller than ICEs (Kim et al., 2020). As mentioned, this report does not consider PEMFCs due to their high sensitivity.

FIGURE 2.10. Efficiency of fuel cells and ICEs as a function of load compared to peak efficiency



Source: Kim et al. (2020).

TABLE 2.1. Volume and weight of possible different components of a 2 500 TEU container ship of 13.5 MW

EQUIPMENT	CAPACITY (MW)	VOLUME (m^3)	WEIGHT (TONNE)
Main engine	13.5	370.7	394.0
PEMFC	6	50.9	20.8
SOFC	6	874.9	271.5
Cracker		19.5	8.0
DC/DC converter	6	30.6	14.0
Motor drive	7	30.9	14.0
Propulsion motor	6.7	28.0	17.8
Selective catalytic reduction	18	150.0	33.0
Scrubber	18	150.0	33.0
HFO storage	-	1 800	1 824
Ammonia storage	-	4 500	3 400

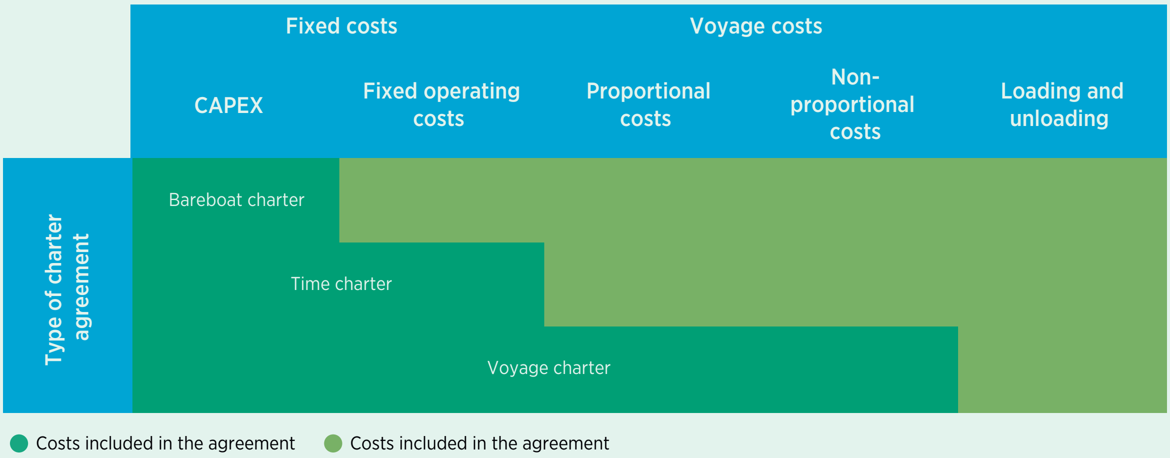
Source: Kim et al. (2020).

There is an additional loss resulting from fuel consumption during the ballast voyage,[14] which can be in the order of 1% of the full cargo of the ship for every 5 000 km. Thus, a typical trip from Japan to Chile (over 20 000 km) would need to leave about 4% of the original cargo load to be used as fuel for the return trip. An alternative could be to use dual-fuel engines that can operate with other fuels, but there would still be an energy penalty or even emissions penalty if high-carbon fuels (e.g. fuel oil or LNG) are used.

Box 2.1. Shipping cost components and types of contract for operation

Chartering, the practice of renting a ship to an operator, is common in international shipping. This allows, for example, the risk of engine failure and maintenance to be retained by the owner of the vessel rather than transferred to the operator. There are different chartering models depending on the type of costs that are covered in the agreement (see Figure 2.11) (d'Amore-Domenech, Leo and Pollet, 2021). At one extreme, the operator owns the ship and retains responsibility for all the costs (fixed, voyage, loading and unloading). This covers one of the most common arrangements, a voyage charter, where the ports and the cargo are specified, and a freight rate is charged, usually expressed per tonne of deadweight. At the other extreme is a bareboat charter, where possession of the ship is handed to the charterer and the charterer hires its own master and crew and is responsible for maintenance.

FIGURE 2.11. Shipping costs covered under various chartering agreements



Source: d'Amore-Domenech, Leo and Pollet (2021).

Transit tariffs can be significant and add to the total transport costs. For example, the tariff for a round trip through the Suez Canal can be in the order of USD 0.65-0.75 million (Wilhelmsen, n.d.) This translates into about USD 0.07/kg of hydrogen cargo for a 60 000 tNH_3 ship. While not apparently that significant, it becomes increasingly important as the cost of renewable hydrogen decreases and also considering this is just for the transit tariff and not the actual fuel consumption or the ship itself.

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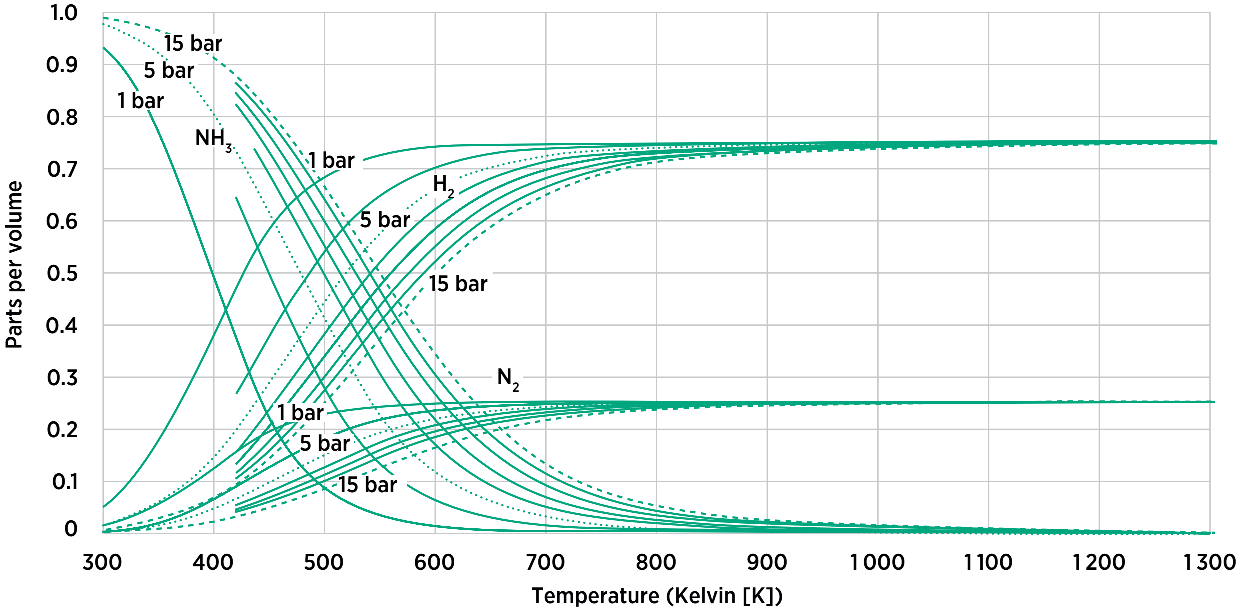
[14] Laden voyage is a term used for the journey from the loading port to the discharge port, while ballast voyage is used for the return trip to the port of origin.

2.5 Reconversion (cracking)

Technology options

Ammonia cracking (also called dissociation or splitting) is the opposite reaction of the synthesis, from ammonia to pure nitrogen and hydrogen. This reaction favours high temperatures and low pressures. The synthesis reaction to produce ammonia releases heat, which means the cracking reaction requires heat to break the bonds in the ammonia. As for temperature, there are two choices – either higher temperatures (950-1 050°C) without the need for an optimised catalyst, or lower temperatures (500-550°C) using a catalyst to accelerate the reaction towards the equilibrium point. Conventional catalysts are based on nickel (requiring 600-900°C), while alternative catalysts use critical minerals (iridium and ruthenium) for the benefit of lower temperatures (350-600°C). The next generation of catalyst could use lithium or sodium at even lower temperatures (250°C) (Makhloufi, 2020). As for pressure, from a thermodynamic perspective (see Figure 2.12) it should be as low as possible (i.e. atmospheric) to increase ammonia conversion and reduce slippage. However, the lower the pressure, the higher the downstream requirements for hydrogen compression. This trade-off results in a typical operating pressure of 20-40 bar for the cracker (H21, 2019a). This pressure increase only results in a small energy penalty since it is done during the liquid phase (i.e. using pumps which require less energy than compressors). Furthermore, hydrogen separation after ammonia cracking can be driven by a high pressure to low pressure gradient, meaning that a higher operating pressure is needed.

FIGURE 2.12. Equilibrium concentrations for ammonia, nitrogen and hydrogen for various process conditions



Source: Hacker and Kordesch (2003).

The best catalyst for ammonia cracking is not yet clear, but nickel-, ruthenium-, and cobalt-based catalysts seem to exhibit the best performance. The choices include the catalyst itself, the promoter and the support. The performance criteria are the ammonia conversion rate, the temperature required, and the amount of catalyst required per unit of hydrogen produced.

Most high-temperature ammonia crackers utilise nickel-based catalysts, as a compromise between activity and cost. These are known as first-generation catalysts and have formulations similar to the nickel-based catalysts used for hydrocarbon reforming. Using potassium as a promoter of ruthenium catalysts and carbon nanotubes as support offers the highest conversion at lower temperatures with a relatively high yield (Bañares-Alcantara et al., 2015). Known as second-generation catalysts, these require critical minerals, of which ruthenium is one. A cheaper option that does not use platinum-group metals are sodium amide-based catalysts, which can exhibit a high conversion even at 500°C (Siemens, 2020). These catalysts are the third generation and still have low technology maturity, with TRLs of 2-4 (Royal Society, 2020).

In instances of full conversion, the product stream is roughly 75% hydrogen (or lower depending on how close to equilibrium the mix is), with the balance being mostly nitrogen[15] (see Figure 2.12) and unconverted ammonia. Hydrogen separation from this mix might not be needed since the forming gas can be used to fire the heater of the ammonia cracker. This would not be enough to supply all the heat and an additional 7% of the pure hydrogen would be needed (Ishimoto et al., 2020).

In cases where ammonia separation is needed, one option is to use absorption/desorption columns with water. This can separate the bulk of the ammonia, but is insufficient if the hydrogen is to be used in a PEMFC (which can require below 0.1 ppm of ammonia) (Siemens, 2020). To achieve this low ammonia content, a pressure swing adsorption unit can be used. In this process, the gas passes through beds that adsorb or release ammonia depending on the operating pressure and which operate in batch mode to go through cycles of adsorption and release. This option would consume in the range of 1.5-2 kWh/kgH_2 including compression (IEA, 2019a; Song et al., 2021).[16] Another option is to use palladium-based membranes, which are selective for hydrogen and can potentially be combined with the cracking in a single step (Katikaneni et al., 2019). This has the benefit of lower equipment count (along with smaller footprint) and the advantage that the separation process in the reactor improves conversion by removing equilibrium limitations, requiring lower temperatures and reducing the energy consumption. However, the cost of palladium-based membranes is high. Separating nitrogen from hydrogen is more difficult than ammonia separation; one option is to use a cryogenic cycle to liquefy the nitrogen. This requires compression to 240 bar in a multi-stage compressor and successive expansion to cool the stream down to -230°C (Siemens, 2020).

Ammonia cracking is not yet a commercial technology on a large scale, but there are similar technologies that may be useful in the de-risking process. It could be done in a way similar to how steam methane reforming (SMR) is done today. Both require high temperatures that would use a firebox with parallel, vertical tubes filled with a catalyst through which the gas would flow. Both reactions are endothermic and need a minimum temperature to achieve enough conversion. This also allows approximation between the cost of an ammonia cracker and an SMR unit (Cesaro et al., 2021). The crackers that are commercially available are for small-scale applications such as annealing of high- or low-carbon steels, stainless steel and various nickel or copper alloys (HyDelta, n.d.), brazing, sintering and deoxidation. This results in most of the commercial designs being available in sizes up to 1 000 normal cubic metre/hour (Nm^3/hr) (equivalent to less than 700 tH_2 per year or what a 5 MW electrolyser would produce with 4 000 operating hours a year). These units operate at pressures of up to 7 bar and can achieve an ammonia content of 20 ppm.

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[15] This mix of hydrogen and nitrogen is commonly called “forming gas”.

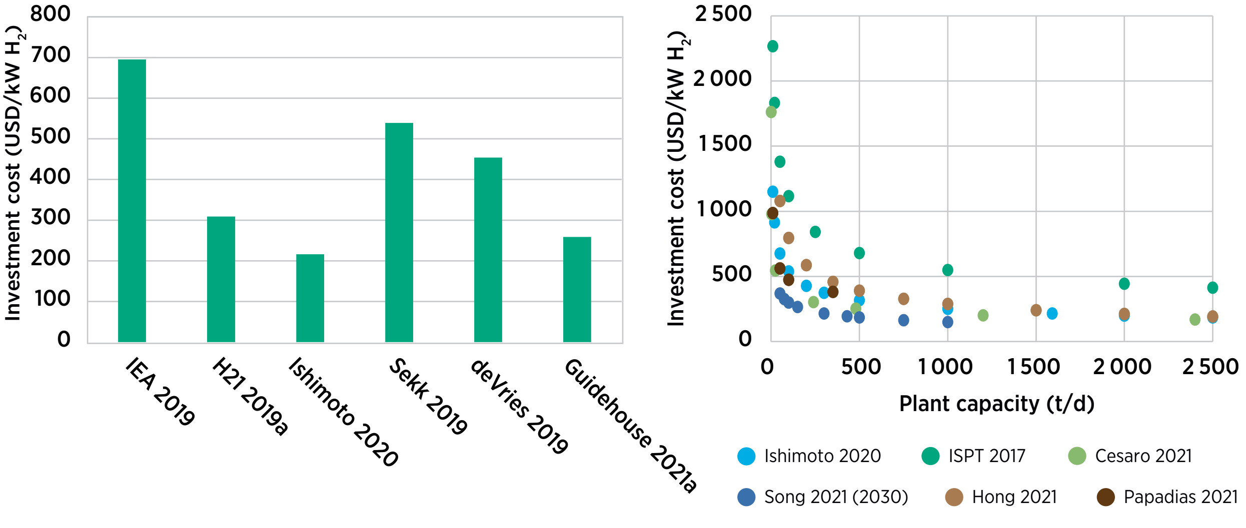
[16] Upper bound corresponds to an operation close to atmospheric pressure for the ammonia cracker.

Larger ammonia crackers are used as part of one process to produce heavy water[17] as a moderator in nuclear reactors. This process includes ammonia synthesis and cracking. The ammonia is used as an intermediary to produce deuterium in the gaseous phase. The cracking step is used to produce the pure deuterium from the enriched ammonia liquid phase. One plant in Argentina (Arroyito) has a cracking capacity of over 1 400 t/d[18] (Smeri, 2015) and a plant in India (Thal) has a cracking capacity of 800 t/d (HWB, n.d.). This would be equivalent to hydrogen production of 0.3 GW and 0.2 GW respectively. There are ammonia crackers that have been in operation for over 30 years and designs are available over a wide range of 100-2 400 t/d (Nielsen, 2021).

Technology performance

As regards technology performance, there are two main parameters: CAPEX and energy consumption. The CAPEX has various cost estimates (see Figure 2.13), where the main difference between them is the scope and the reference capacity. Some studies (Cesaro et al., 2021; Ishimoto et al., 2020; ISPT, 2017) use a scaling factor (0.67-0.745) to estimate the cost for different capacities. Cesaro et al. (2021) use cost estimates for an SMR unit as reference as the design of the ammonia cracker is expected to be similar. The main cost driver of the ammonia cracker is the furnace with the vertical tubes filled with catalyst, complemented by the heat recovery. The purification step is a relatively small part of the total cost. The CAPEX of ammonia cracking equipment may be between one third and one half of that for ammonia synthesis at the exporting terminal.

FIGURE 2.13. CAPEX for ammonia cracking based on various literature estimates (left) and as a function of plant size (right)



Note: Cost is expressed in terms of the cracking output (1 kW of hydrogen produced).
Sources: Cesaro et al. (2021); Guidehouse (2021a); H21 (2019a); Hong (2021); IEA (2019a); Ishimoto et al. (2020); ISPT (2017); Papadias, Peng and Ahluwalia (2021); Sekkesæter (2019); Song (2021); de Vries (2019).

Cost estimates indicate that producing hydrogen by cracking ammonia involves CAPEX of about one third of a hydrogen plant, but the cost of NH_3 feed will be much higher than the cost of a natural gas feed. This is because the cost of the ammonia will include the original feedstock plus all the upstream ammonia production facilities and shipping requirements.

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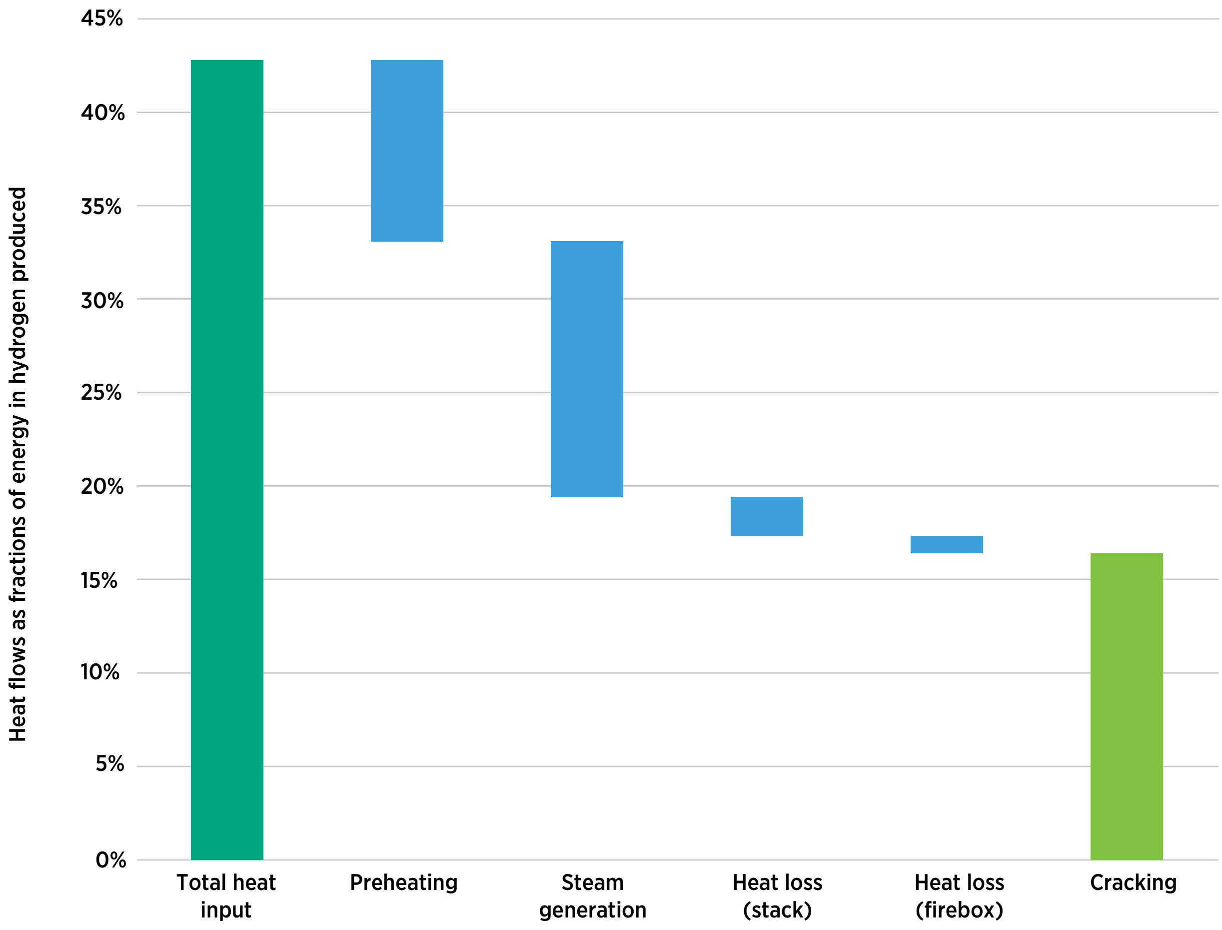
[17] Water that uses deuterium, a hydrogen isotope, instead of hydrogen, to give it different nuclear properties.

[18] Plant has two synthesis units of 2 150 t/d, with the capacity of the cracker being around a third of the synthesis capacity (Sawant et al., 2006).

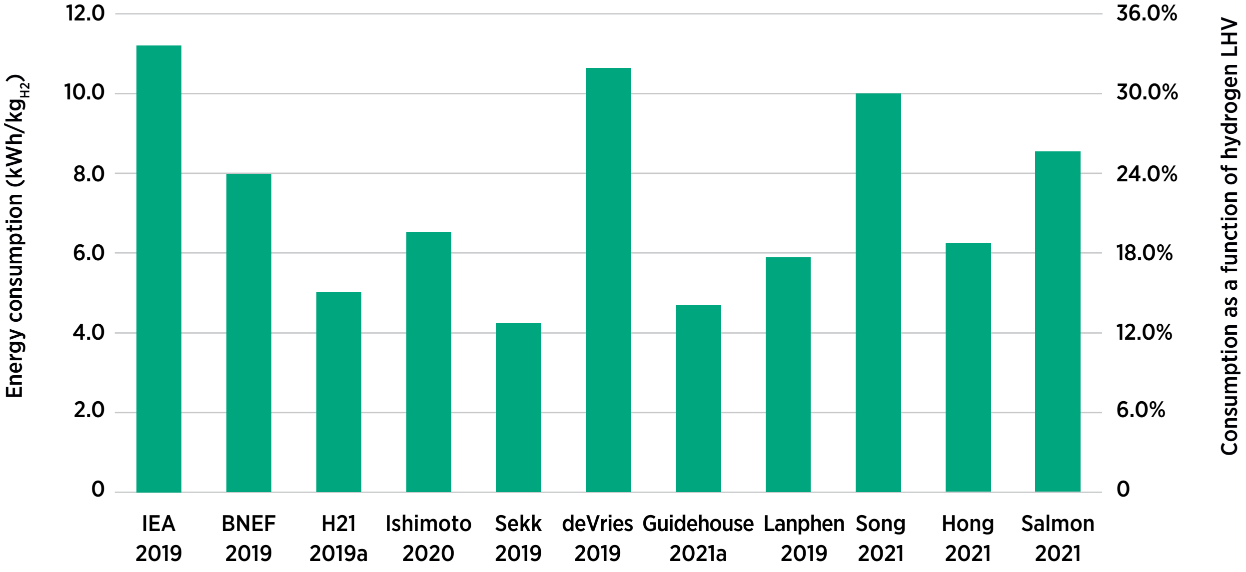
As for energy consumption, the minimum energy that the cracker can consume is 1.01-1.08 MJ/kg of ammonia, which is about 5-6% of the energy contained in the ammonia. Additionally, there are thermal energy losses in the cracker of 4-7% (Giddey et al., 2017; Siemens, 2020). About a third of the thermal input is used in heat recovery for steam generation, which can then be used for compression of the hydrogen produced or to drive the hydrogen purification. About 20% of the thermal input to the cracker is needed to heat the gas mixture to the cracking conditions (Beach, 2020). To achieve these high temperatures, part of the hydrogen produced could be burned, resulting in additional energy losses. At the same time, the hydrogen produced contains more energy than the ammonia feed, which means part of the energy input for cracking ends up as chemical energy in the bonds of the hydrogen. Based on this, the minimum energy that can be consumed is about 15% of the energy contained in the hydrogen, and up to 30% considering hydrogen and thermal losses and low heat recovery for preheating the feed. An overview of the thermal flows of a cracker is shown in Figure 2.14 using the energy consumption data from various references in Figure 2.15. The main driver for the differences between them is the elements included (i.e. just cracking, or also losses and other equipment). For reference, industrial companies estimate a 75% conversion efficiency for ammonia to hydrogen on a weight basis, which translates into 86% on an energy efficiency basis (Nielsen, 2021). This includes hydrogen purification after ammonia cracking.

FIGURE 2.14. Use of the thermal heat from a heater for a 200 tH_2/d ammonia cracker



Source: Siemens (2020).

FIGURE 2.15. Energy consumption for ammonia cracking



Note: Energy consumption is expressed as a function of hydrogen's LHV for reference, but the heat could come from an external source resulting in an additional energy input to the process.
Sources: BNEF (2019); Guidehouse (2021a); H21 (2019a); Hong (2021); IEA (2019a); Ishimoto et al. (2020); Lanphen (2019); Salmon (2021); Sekkesæter (2019); Song et al. (2021); de Vries (2019).

3

LIQUID HYDROGEN

LIQUID HYDROGEN

Highlights

The liquefaction of hydrogen is already performed commercially today, but only on a very limited scale. The average facility would need to scale up by a factor of more than 220 to reach a size similar to LNG plants today and reach full economies of scale for global trade. Given this disparity between what exists now and what is needed, the benefits in cost and efficiency of such a scale-up are unclear. Hydrogen-powered ships are not yet available and international shipping of liquid hydrogen is not done commercially. The reconversion (regasification) process is relatively simple and should not pose major limitations on its use for global hydrogen trade.

A key barrier for this pathway is the low temperatures that are needed for liquefaction (-253°C), which requires more expensive equipment to reduce the thermal losses and to handle the cryogenic temperatures. This also leads to high energy consumption to reach and maintain such conditions, or alternatively to high boil-off losses that will impact overall efficiency. This pathway could build upon lessons learned from the LNG industry given the similarity in the technology, bearing in mind that the cryogenic conditions are much more challenging (-253°C vs -160°C).

The major energy consumption in the value chain is in the liquefaction step, where further work is needed to understand its limits. Existing liquefaction plants consume the equivalent of about 30-36% of the energy contained in the hydrogen (although this consumption is in the form of electricity and not directly from hydrogen). This could potentially decrease to 15% with further research, engineering and scaling up.

3.1 Technology status

Liquefaction

Hydrogen liquefaction was first achieved in 1898 by James Dewar, with larger-scale implementation in the late 1950s as part of the NASA space programme. Liquid hydrogen is used for a range of niche applications, including in the semiconductor industry and to fuel military vehicles and vessels. It is transported in trailer trucks (up to 4-4.5 tH_2 payload [Reuß et al., 2017]). This means most operational liquefaction plants are small (~ 5-15 t/d per train), the largest single train having a capacity of 34 t/d in the United States (Aasadnia and Mehrpooya, 2018).[19] Global liquefaction capacity is almost 600 t/d (Linde, 2019), equivalent to just over 0.5 GW of hydrogen capacity. Almost 80% of this capacity is in North America, complemented by Europe and Japan (see Figure 3.1). The main technology providers are Air Products (United States), Air Liquide (France) and Linde (Germany).[20] This means hydrogen liquefaction is already de-risked and used in commercial applications.

The main limitations to scaling up for global trade are the current maximum size of the facilities related to certain technological barriers such as the maximum tip velocity in expanders, maximum sizes for compressors and turbines for the refrigerant mix, use of new mixes of refrigerants, and bearing technologies and rotor designs to support higher expander and compressor speeds. There is also further work needed to accurately estimate the fluid properties of new mixes of refrigerants (e.g. with neon) (Cardella, Decker and Klein, 2017). Solutions for some of these issues already exist. For instance, the limitation on maximum compressor size can be overcome by changing from piston to centrifugal compressors, although high tip velocities might still be a challenge for these. A solution for the maximum size of turbines could be technology transfer based on existing technology designs for nitrogen and hydrocarbon turboexpanders, which are already available for large plants. For the bearings, there could be a transition towards the standard use of dynamic gas bearings replacing oil bearings (Ohlig and Bischoff, 2012). These solutions still need to be engineered, de-risked and implemented for liquid hydrogen.

A reference point for liquid hydrogen is LNG, which is the closest cryogenic and large-scale process. Global LNG liquefaction capacity stood at 453 Mt/yr at the end of 2020 (IGU, 2021a), equivalent to 1.24 Mt/d or more than 500 000 times the equivalent hydrogen capacity in energy terms.[21] The potential for liquefaction to play a role in global hydrogen trade relies upon the possibility of cost reductions both by global learning-by-doing and by scaling up the average plant size to achieve economies of scale.

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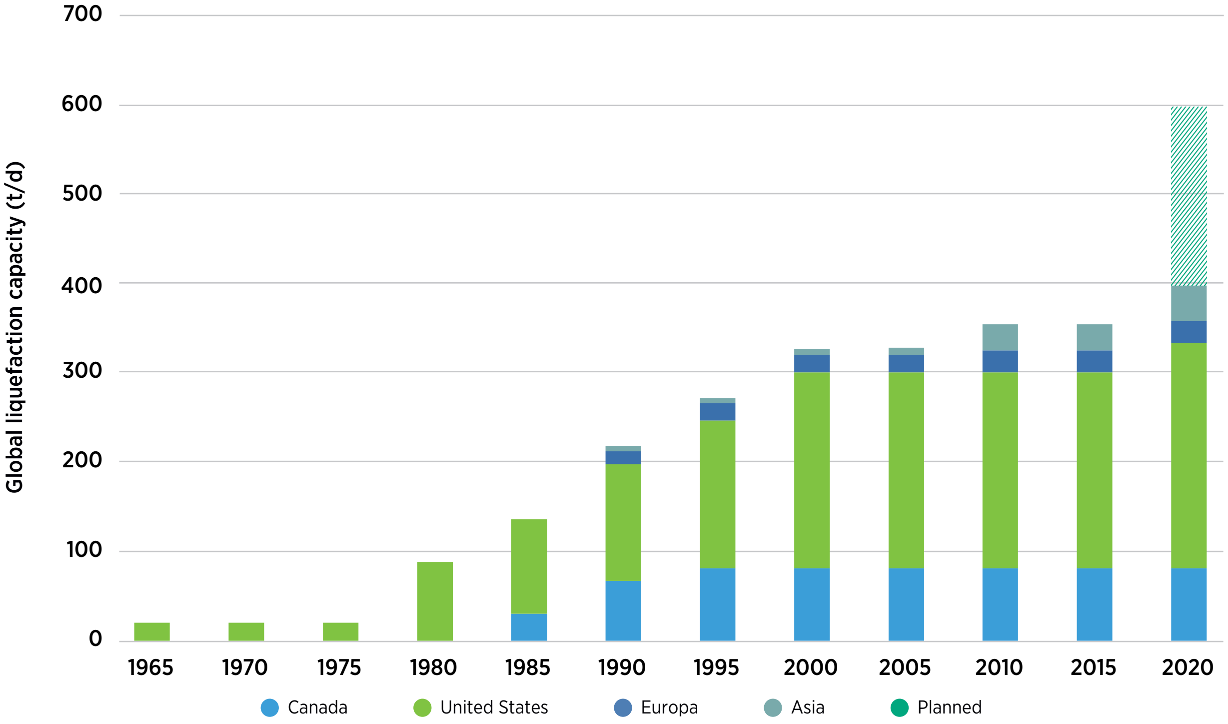
[19] The largest ever built was in the United States and had a capacity of 54 t/d. It started operation in 1964, but it is no longer in service (Aasadnia and Mehrpooya, 2018).

[20] Praxair was the other company with significant liquefaction capacity, but it merged with Linde in 2018.

[21] Using the LHV ratio instead of the energy density ratio.

FIGURE 3.1. Global hydrogen liquefaction capacity growth since the 1960s



Notes: Seven plants with a total capacity of 121 t/d have been excluded as they are out of operation. See Section 3.2 for an overview of the planned projects (including some that were completed over 2021).
Sources: Krasae-in, Stang and Neksa (2010); Linde (2019), project survey and expert input.

Liquid hydrogen storage

Storage of liquid hydrogen is already deployed on a large scale. The largest sphere[22] in operation is used by NASA and has a volume of 3 200 m^3 (227 tH_2). The construction of a new 4 700 m^3 sphere (334 tH_2) started in 2019 and is expected to become operational in 2022. Kawasaki Heavy Industries announced in December 2020 the completion of a basic design for a 11 200 m^3 spherical tank with a working capacity (considering the ullage requirement) of 10 000 m^3 and a boil-off ratio of less than 0.1% per day (Kawasaki, 2020). The company has the most advanced ship design, which would have four tanks of 40 000 m^3 each (Kawasaki, 2021), requiring a further scale-up by a factor of four. Therefore, similar to liquefaction, storage would need to be scaled up multiple times to be able to match the scale required for global trade, whereby commercial-scale projects are expected to use tanks of 50 000 m^3 (KHI, 2019). Aside from liquefaction and storage, no ships currently transport or use liquid hydrogen, which has to date been limited to demonstration projects (see Section 3.2). This area is still about a decade away from large-scale implementation (KHI, 2019). Hydrogen regasification is a relatively simple process that uses seawater or air to heat the liquid hydrogen. This requires materials that can withstand the cryogenic conditions, but it is not expected to represent a critical area for R&D.

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[22] A spherical shape reduces the surface area and heat transfer.

3.2 Project pipeline

Liquefaction plants

The construction of several small hydrogen liquefaction plants have been announced, but so far none goes beyond current limits or approaches what would be required for large-scale global trade. The following are a selection from company press releases and news stories:

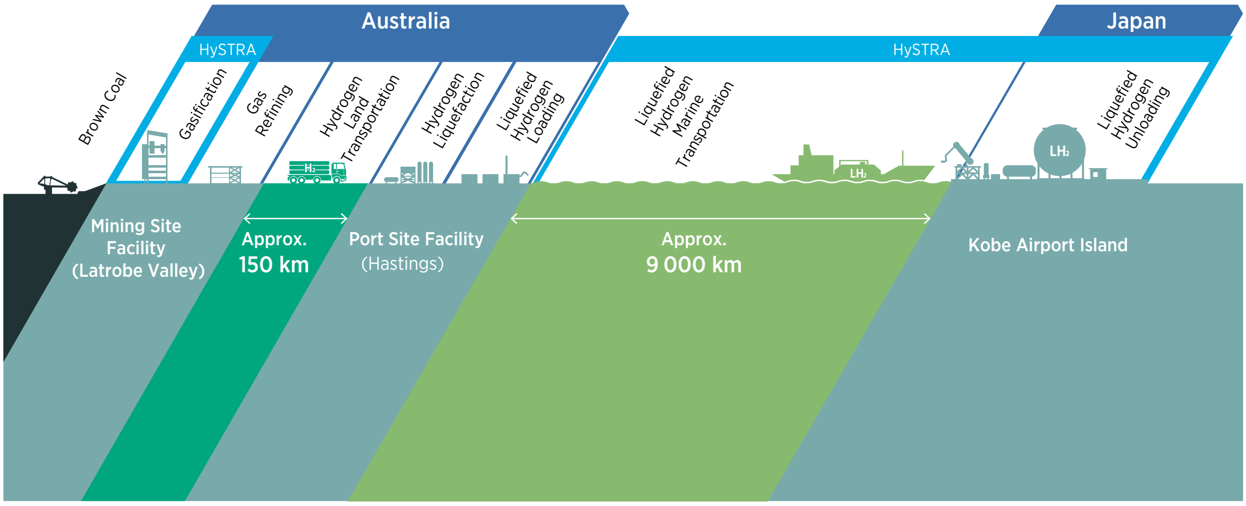
- Hyosung and Linde announced plans to build a 13 000 t/yr (35 t/d) liquefaction plant in Ulsan (South Korea). Operation at full load is expected by May 2023. The planned investment is USD 245 million (including transport and refuelling stations).
- In Texas (United States), two 30 t/d plants came online in 2021, both drawing from the existing hydrogen pipeline network on the Gulf Coast. One from Linde came online in July 2021 and the other from Air Products in October 2021.
- Air Products has announced plans to build a 30 t/d plant in Edmonton, Alberta (Canada) as part of Western Canada's Hydrogen Hub, together with an autothermal reformer for hydrogen production from natural gas and the existing pipeline network. The plant is expected to come on stream in 2024.
- Air Products is planning to build a 30 t/d plant in Haiyan, Zhejiang (China), starting operation in 2022. This is part of an MoU signed with China Jiutai Group, which has existing coal-to-syngas facilities.
- Air Products proposed a 10 t/d plant in Carson, California (United States) with on-site storage, operation due to start in 2022.
- Air Liquide has signed an agreement with Doosan Heavy Industries to build a 5 t/d liquefier in Changwon (South Korea), expected to be operational in early 2023. The company has designs for up to 50 t/d with energy consumption of less than 10 kWh/kg (Air Liquide, 2021). It also constructed a 27 t/d plant in California in 2020 at a cost of USD 150 million.
- Air Liquide is also constructing a 30 t/d plant in Nevada (United States) with a total investment of USD 200 million which is expected to come online in 2022. Hydrogen production is from steam reforming of biogas, landfill gas and waste-water treatment gas. The hydrogen produced will be used for light- and heavy-duty vehicles.
- Air Liquide also plans to develop a 90 t/d facility (three plants of 30 t/d) in South Korea, which is expected to come online in the second half of 2023.
- Plug Power (US company) is planning to have a hydrogen liquefaction capacity of 500 t/d by 2025 and 1 000 t/d by 2028.
- Origin Energy is collaborating with Kawasaki Heavy Industries to develop a 300 MW project (36 500 tH_2/yr) to export liquid hydrogen from the Port of Townsville (Queensland, Australia) to Japan. The plant is expected to be operating by 2025 with the first exports to Japan by 2026. The project is now in the front-end engineering and design phase.
- Saulsbury and Chart Industries were awarded a pre-front end engineering and design study in October 2021 for a 30 t/d plant in the United States.
- The H2OK project in Oklahoma, United States, entered the front-end engineering and design phase in January 2022. The project is being led by Woodside (Australian oil and gas company), which aims to make a final investment decision by the second half of 2022 and start operation by 2025. The initial plant capacity is 90 t/d of liquid hydrogen (290 MW facility) for the heavy transport sector, with enough space in the location to double the capacity.

Liquid hydrogen shipping

The HySTRA Project

As the earliest project to address liquid hydrogen shipping,[23] the HySTRA[24] project was launched in Japan in 2015 with the aim of achieving a pilot scale in 2020 (1 250 m^3 ship), scaling up to commercial scale by the mid-2020s and reaching full commercial scale (2 x 160 000 m^3) by 2030. The energy source for the hydrogen is brown coal from the Latrobe valley in Victoria (Australia), converted to hydrogen using gasification. The hydrogen is then transported for 150 km to the port site in Hastings, where it is liquefied and loaded into the ship. After a 9 000 km journey by ship (see Figure 3.2), it arrives at Kobe Airport Island in Japan (with storage tanks of 2 500 m^3), where the hydrogen is used for the airport's operation and to demonstrate power generation (only modifying the combustors). Partners in the project include Kawasaki Heavy Industries, J-POWER, Iwatani, Marubeni, AGL, Sumitomo, Shell, ENEOS and K-Line.

FIGURE 3.2. Hydrogen value chain in the HySTRA project from Australia to Japan



Source (HySTRA, n.d.).

The project was launched in 2015 with support from Japan's R&D agency, New Energy and Industrial Technology Development Organization (NEDO), for the hydrogen production step, shipping and regasification, and support from the Australian (and Victorian) government for the rest of the value chain. The construction of the ship (the *Suiso Frontier*) was finalised in late 2019. The first shipment with 75 t of liquid hydrogen took place in January 2022. The project is adopting a sequential de-risking of the value chain, where currently the hydrogen is produced from coal gasification without CCS. This, combined with the small scale, efficiency losses and the use of diesel for transport (instead of the hydrogen boil-off, which is burned without power recovery), results in high GHG emissions for the demonstrator. Project participants expect these to decrease as the value chain moves towards its large-scale model.

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[23] There are several small projects for ferries and other smaller applications, which are left out of this review as this report focuses on large ships for hydrogen trade. For an overview of smaller applications see ICCT (2022) and Global Maritime Forum (2021).

[24] The project is also called Hydrogen Energy Supply Chain (HESC).

In May 2021, based on the *Suiso Frontier* design, and with support from NEDO, Kawasaki received an AiP to develop a 160 000 m^3 ship with a commercialisation timeline of the mid-2020s. The design uses four tanks of 40 000 m^3 each. It satisfies the IGC Code, IMO recommendations for Carriage of Liquefied Hydrogen in Bulk and has cleared a HAZID risk assessment (Kawasaki, 2021). The main features of the cargo containing system are:

- Suitable for large-scale transport of liquefied hydrogen.
- Uses a self-supporting design to respond flexibly to the thermal contraction that occurs during hydrogen loading.
- Has better insulation to reduce boil-off gas production.
- Uses boil-off gas as fuel for the ship.

In December 2021, the *Suiso Frontier* was incorporated into the register of the Japanese ship classification society ClassNK. This follows the publication of class rules and guidelines for liquefied hydrogen carriers by ClassNK in 2017 (Ship Technology, 2021).

Other projects

In October 2020, another liquid hydrogen ship (20 000 m^3) from a joint industry project by Hyundai Heavy Industries, Korea Shipbuilding and Offshore Engineering, and Hyundai Mipo Dockyard received an AiP. The AiP was granted by the Liberian Registry as flag state and the Korean Register as Class Society. A novel aspect of the ship is that any boil-off gas from the cargo is used to drive the ship using fuel cells. Hyundai Heavy Industries aims to have the technology ready by 2025.

In October 2021, Hyundai Glovis signed an MoU with Air Products to establish a liquid hydrogen supply chain. Hyundai Glovis would secure a stable supply source of the hydrogen, while Air Products would provide the technology expertise on liquefaction. Hyundai Glovis is also looking to use ammonia for its shipping operations, while Air Products could provide the ammonia cracking technology.

3.3 Conversion (liquefaction)

Hydrogen is the lightest element in the world and requires extreme conditions for liquefaction – a temperature of -253°C (compared with -160°C for LNG). To achieve these low temperatures, multiple refrigerant cycles are needed and these are the cause of most of the energy losses in the process. Assuming an ideal process, the thermodynamic minimum energy consumption can be expressed as a function of the inlet pressure (see Figure 3.3). With a typical feed pressure of 20 bar, the minimum work is about 2.67 kWh/kgH_2 (Berstad, Skaugen and Wilhelmsen, 2021). This is equivalent to about 8% of the energy contained in the hydrogen.[25]

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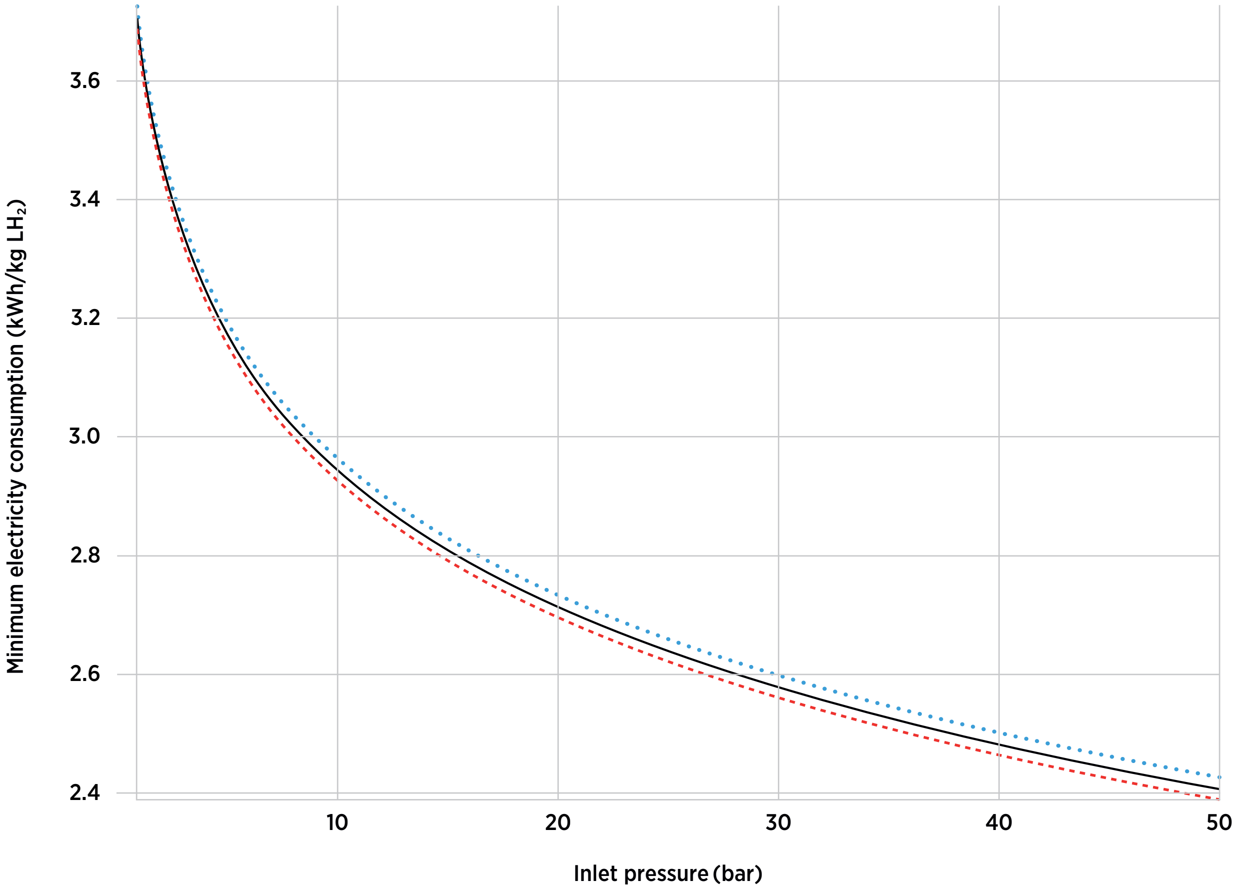
[25] This is used to put the value into perspective, but the energy input is in the form of additional electricity rather than sourced from the hydrogen.

FIGURE 3.3. Minimum liquefaction energy consumption as a function of inlet pressure



Notes: Lines in the figure refer to the outlet pressure: 1.3 bar (blue dash-dot line), 1.5 bar (solid line), 1.7 bar (red dashed line). Product hydrogen is assumed to be a saturated liquid hydrogen, where the para-hydrogen mole fraction has its equilibrium value at the saturation temperature.
Source: Berstad, Skaugen and Wilhelmsen (2021).

However, the actual process is far from ideal: there are pressure, heat and energy losses, which all add to the minimum work that is needed.

Sources of losses during liquefaction

The specific categories from where losses can come are heat exchangers, ortho-para conversion, purification of hydrogen gas, compression equipment, expansion equipment, nitrogen liquefaction process, and insulation (Aasadnia and Mehrpooya, 2018). The losses are also a function of the specific process configuration used. The simplest process would be with cooling and expansion. First, hydrogen is compressed to above the critical point (13 bar) to 20-30 bar. Later, the hydrogen feed is pre-cooled, typically with liquid nitrogen or other refrigerants to achieve temperatures of around -190°C. The hydrogen is further cooled using a cryogenic refrigeration cycle, typically using hydrogen or helium, and is then expanded to close to atmospheric pressure in the liquid hydrogen storage tank.

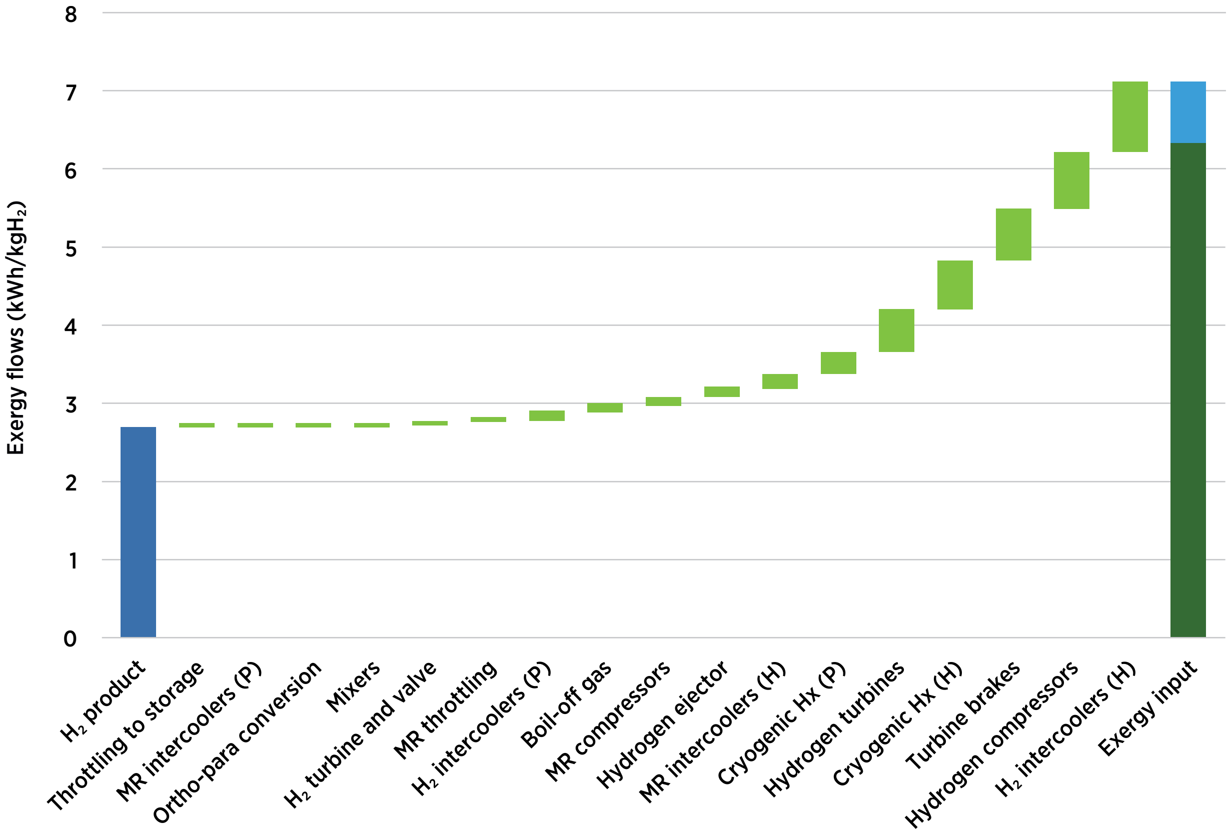
There are multiple variations in the liquefaction process based on pressure levels, refrigerant used, use of an expansion turbine or a throttling valve, open or closed cycles, use of cascade systems (where one cycle provides the cooling for the next cycle), and ratio of mass through the expander, among others (Aasadnia and Mehrpooya, 2018). These variations have led to different cycles including Linde, Linde-Hampson, Claude, Brayton, and mixed-refrigerant.

Figure 3.4 shows the breakdown of exergy losses for one of these cycles to give a sense of the major contributors to efficiency losses in the system. This will vary depending on the specific process configuration, leading to different deviations from ideality and different real energy consumption for each process (see Figure 3.5). Considering these losses, real energy consumption for existing plants is in the order of 10-15 kWh/kgH_2 (Cardella, 2018, 2019; NCE, 2016) with a strong dependence on size. The smaller plants (1-5 t/d) already constructed have energy consumption of 12-15 kWh/kgH_2, while the state-of-the-art plants, and especially larger sizes of 25-30 t/d, can already reach 10 kWh/kgH_2 (Cardella, Decker and Klein, 2017).[26]

Auxiliary equipment not part of the core liquefaction unit can add another 6% to the overall energy consumption. These can include (IdealHy, 2013a):

- instruments air compressor
- vacuum pump for the coldboxes
- control system, safety devices and lighting
- cooling tower water pumps and fans
- processing of the boil-off from the storage tank.

FIGURE 3.4. Breakdown of exergy losses for a Claude cycle with mixed refrigerant pre-cooling



Notes: Exergy is a measurement of quality of energy (e.g. 1 MJ of water at 800°C has more exergy than 1 MJ of water at 30°C). It is the amount of work that a system can perform when brought to environmental conditions. It has four components: kinetic, potential, thermo-mechanical, and chemical. (H) = losses during heat transfer or rejection; (P) = losses due to pressure drop; Hx = heat exchangers; MR = mixed refrigerant; boil-off gas is actually part of the exergy output of the process, but it is added separately to focus on the exergy of the main liquid hydrogen product.
Source: Berstad, Skaugen and Wilhelmsen (2021).

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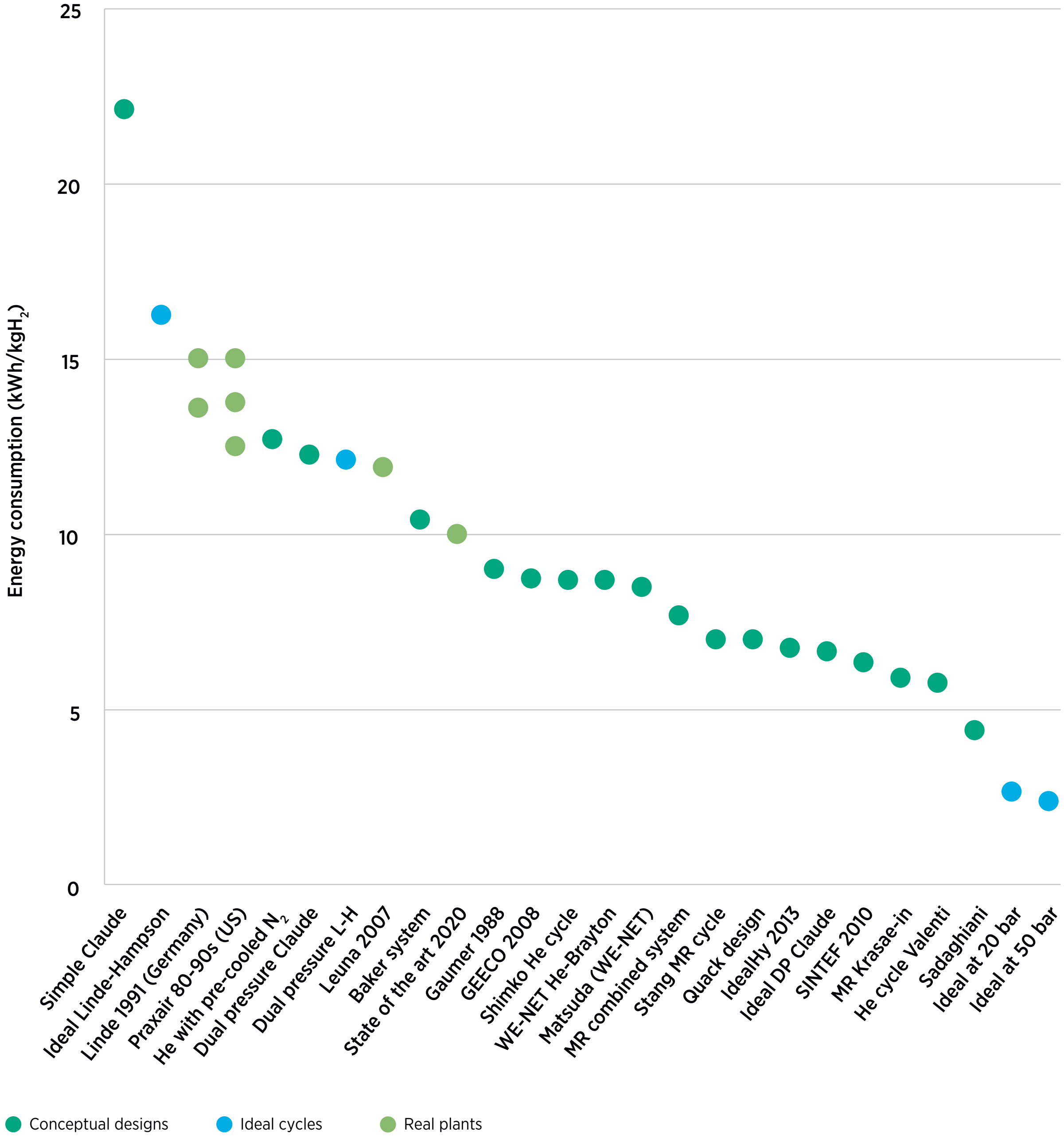
[26] For specific conditions and large sizes (above 60 t/d), energy consumption of 7 kWh/kgH_2 is possible today (Air Liquide, 2021).

The largest exergy losses take place in the hydrogen intercoolers, compressors and cryogenic heat exchangers. Most of the losses are associated with the lower temperature range (after pre-cooling with nitrogen), which is expected given these temperatures are more difficult to achieve and the temperature differential between the streams is smaller (decreasing the driving force). Relatively small losses, such as pressure drop across heat exchangers, accumulate and add up to about 8% of all losses (Berstad, Skaugen and Wilhelmsen, 2021).

FIGURE 3.5. Energy consumption for operating plants, conceptual designs and ideal cycles for hydrogen liquefaction



Notes: See Aasadnia and Mehrpooya (2018) and IdealHy (2012) for the references for each process; ideal processes at 20 and 50 bar are the thermodynamic minimum based on process conditions, while other ideal processes depend on the cycle configuration. References for operating points for real plants date back to early 2000s.
Sources: Aasadnia and Mehrpooya (2018); Cardella (2018); IdealHy (2012, 2013a).

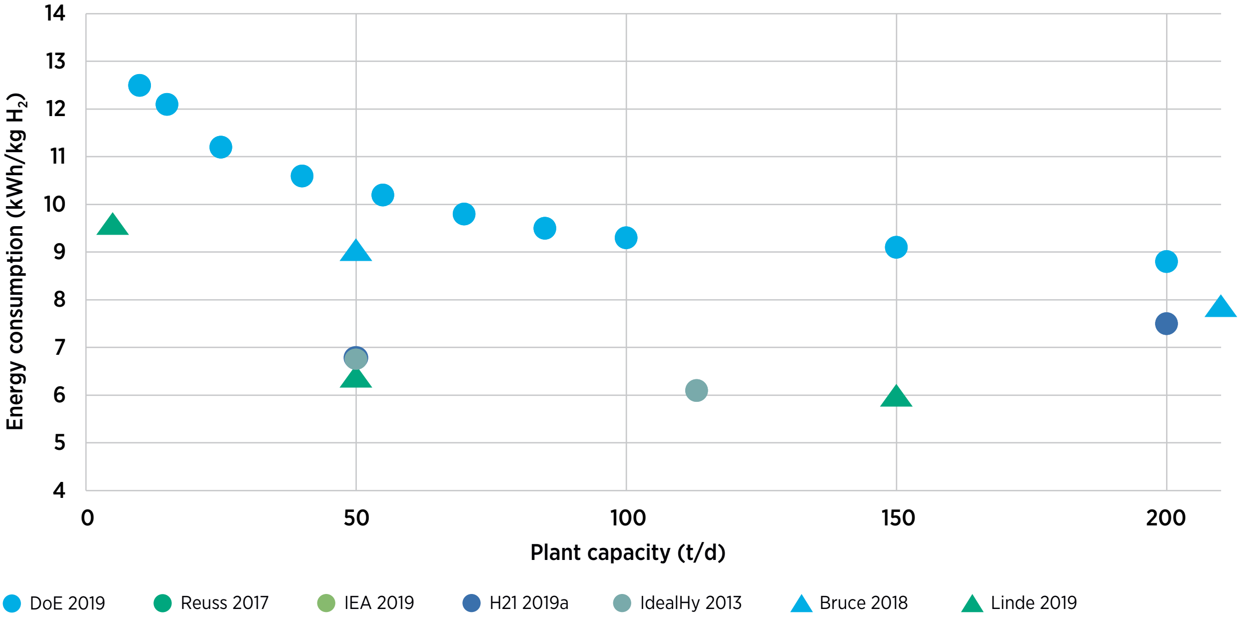
Based on these losses, several options are available to improve the efficiency of the cycle (Berstad, Skaugen and Wilhelmsen, 2021):

- Recover power from the shafts of the hydrogen turbines (0.65 kWh/kg exergy loss).
- Use an improved mixed-refrigerant cycle with a pre-cooling temperature of 80 K (changing the chemical composition of the refrigerant and high- and low-pressure levels).
- Replace the throttling valve with an expander (reduce the enthalpy of the stream instead of isenthalpic expansion).
- Extend the temperature range of the mixed-refrigerant cycle by decreasing the pre-cooling temperature.
- Reduce the pressure drop in the ejector that throttles the pre-cooled hydrogen.
- Use high-temperature chillers to supplement ambient cooling.
- Recover waste heat from the intercoolers.
- Use a mix of helium, neon and hydrogen in the refrigerant cycle, leading to higher molecular mass that makes possible the use of centrifugal compressors (instead of reciprocal piston compressors), which exhibit better economies of scale.

The influence of plant size on energy consumption

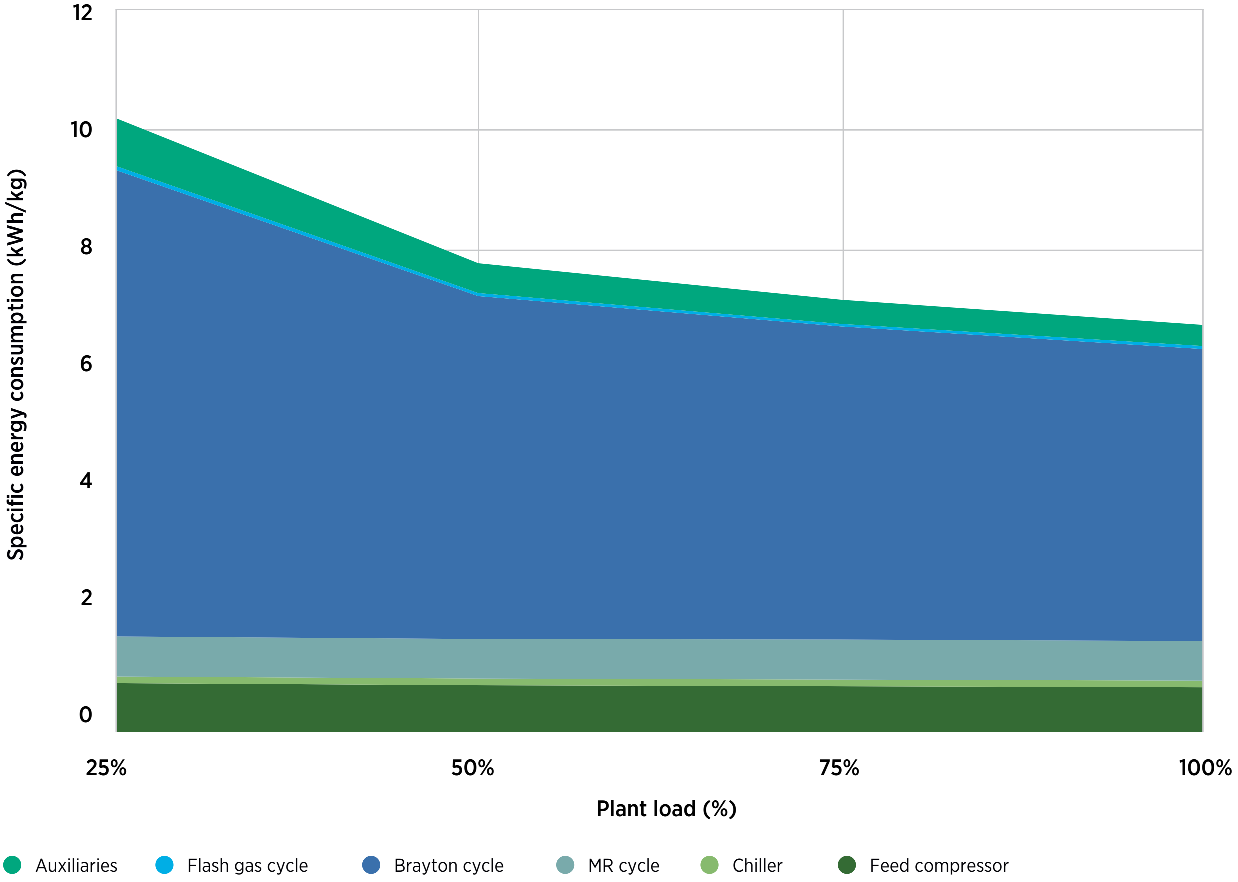
Two other parameters can have a large influence on the specific energy consumption of the liquefaction process: plant size and partial load. Increasing the plant capacity from today's typical scale (5-10 t/d) to a larger scale of 150-200 t/d is expected to decrease the energy consumption by 30-38% (see Figure 3.6). Efficiency at a larger scale has an asymptotic behaviour, where further increases in size only lead to marginal benefits in efficiency. Valenti and Macchi (2008) proposed a much larger plant of 860 t/d, which achieved a specific energy consumption of 5.29 kWh/kg. Regarding partial load, the liquefaction plant can operate down to 25% of the design load. The specific energy consumption with load is dependent on process configuration, but a specific example with a 50% higher energy consumption for the lower load is presented in Figure 3.7 (IdealHy, 2013a).

FIGURE 3.6. Specific energy consumption for liquefaction as a function of plant capacity



Sources: Bruce (2018); DoE (2019); H21 (2019a); IdealHy (2013); IEA (2019); Linde (2019); Reuss (2017).

FIGURE 3.7. Specific energy consumption for liquefaction as a function of plant load



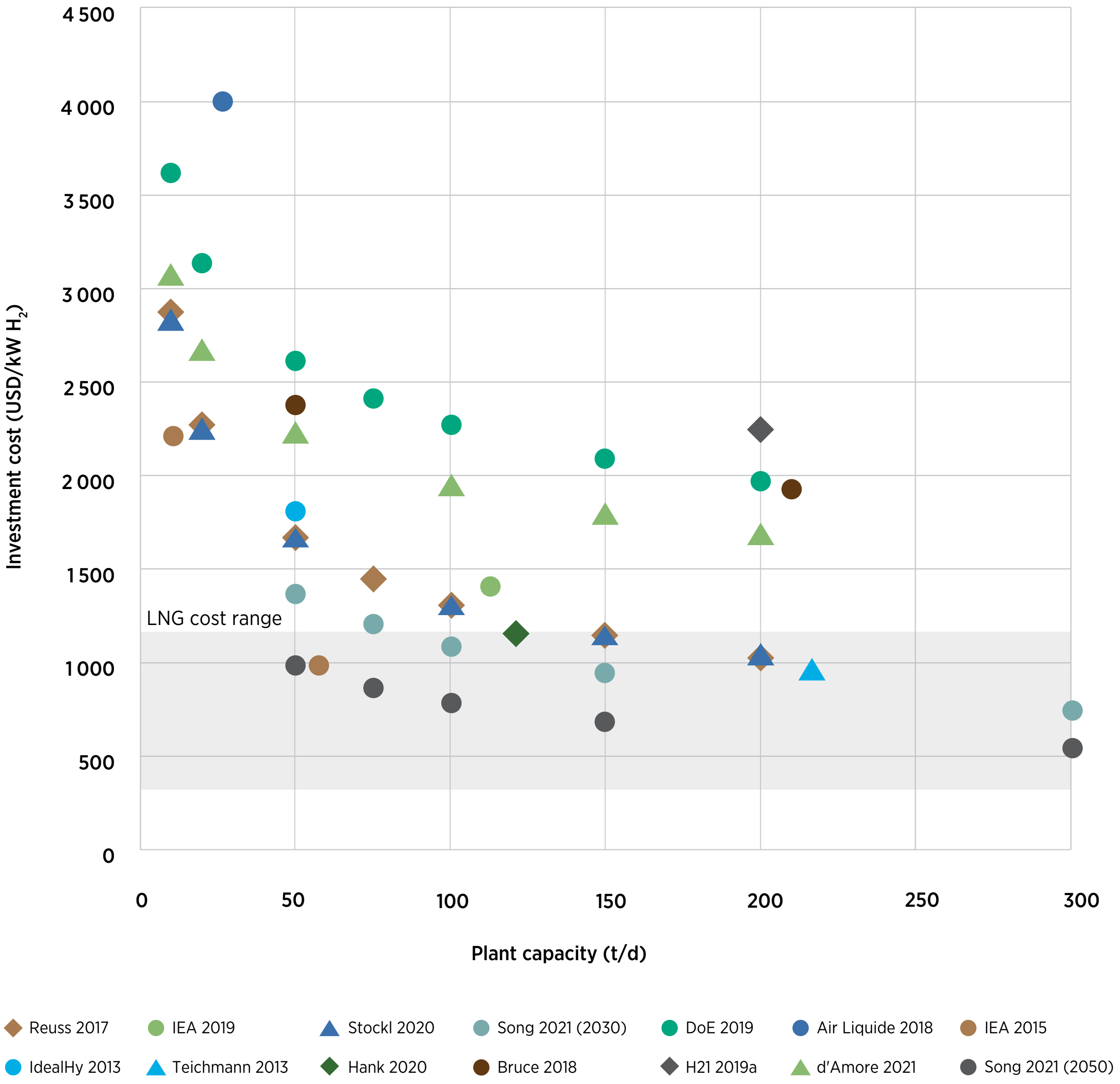
Notes: This is an indication of energy consumption's relationship with load for a specific design and may be different for other plant configurations.
Source: IdealHy (2013a).

Liquefaction also requires a catalytic conversion step. Hydrogen is a diatomic molecule and can exist in two forms depending on the spin of the nucleus: ortho and para. The ratio between them is mostly a function of temperature. At room temperature, the equilibrium concentration is about 75%/25% ortho/para, while at the boiling point, the equilibrium concentration is 0.2%/99.8% ortho/para. The ortho- to para- conversion releases heat, which means if it takes place once the hydrogen is liquid, this conversion can boil part of the liquid hydrogen, reversing the process in which so much energy has been invested. The heat generated for the ortho-para conversion is 0.388 kilocalories per mole (kcal/mol), while the latent heat of vaporisation is 0.213 kcal/mol (Aasadnia and Mehrpooya, 2018). This means that this conversion should be promoted at higher temperatures, but given this is a slow reaction, catalysts are needed. Modern liquefiers use a continuous ortho-para conversion below the precooling step (below about -190°C).

Capital cost for liquefaction

The design of the liquefaction unit is not only based on energy consumption – for most design choices there is a cost and efficiency trade-off (Cardella, Decker and Klein, 2017). Thus, it is important to include the other main component of techno-economic performance: the CAPEX. Here, there are two main factors to consider: economies of scale by increasing the plant capacity; and project cost as a function of the scope. The effect of economies of scale is shown in Figure 3.8. For plants smaller than 50 t/d (all the existing plants), the specific costs increase significantly from about USD 2 000/kWH_2 for a 50 t/d capacity, to USD 3 000/kWH_2 for 20 t/d. The scaling exponent (i.e. how fast the cost decreases with an increase in capacity) ranges from 0.67 (Reuß et al., 2017; Stöckl, Schill and Zerrahn, 2021) to 0.8 (DoE, 2019; d'Amore-Domenech, Leo and Pollet, 2021). At the same time, the uncertainty of the initial cost reference is also relatively high, which leads to a factor of almost two between the minimum and maximum specific investment cost across almost the entire capacity range. This uncertainty was captured as part of the cost range of the *Optimistic* and *Pessimistic* scenarios. Figure 3.8 also shows how hydrogen liquefaction compares with methane liquefaction, given that this is a similar process (i.e. cryogenic conditions) and that is already a developed industry that could serve as benchmark (see Box 3.1).

FIGURE 3.8. Specific CAPEX for hydrogen liquefaction as a function of plant capacity



Notes: Grey area represents the cost range for methane liquefaction plants, which also use a cryogenic process. However, methane liquefaction is done at -162°C, while hydrogen liquefaction is done at -253°C leading to an inherently higher cost. LHV has been used to convert capacities from t/d to kWH_2.
Sources: DoE (2019); d'Amore-Domenech, Leo and Pollet (2021); H21 (2019a); Hank et al. (2020); IdealHy (2013a); IEA (2015, 2019a); Reuß et al. (2017); Song et al. (2021); Stöckl, Schill and Zerrahn (2021); Teichmann, Arlt and Wasserscheid (2012).

Liquefaction plant capacities would need to increase by multiple times from their current values to reach the scale needed for global trade. This opens the possibility of cost reductions simply by scaling up the capacity of a single train. This is limited by the size of the equipment. At some point it becomes too large to manufacture or to transport (e.g. road width or bridge height) and the extra costs are higher than the lower material use. For comparison, in LNG liquefaction one factor that limits the size of a single train is the main cryogenic heat exchanger, where the lowest temperatures of the process are achieved. This practical limitation is expected to be similar for hydrogen liquefaction. The maximum feasible dimensions for the coldbox are limited by the dimensions that can transported via road (which are dependent on the country) or ship. This defines a maximum diameter of 4-5.5 m and length of 20-40 m (IdealHy, 2012). One alternative to overcome this limitation and achieve larger sizes is to use transport by ship rather than road. Another is to deliver pre-packaged transportable coldboxes or systems to gather and assemble them on site (as it is done for air separation units that also use coldboxes) with the trade-off that some work is needed (e.g. pressure testing) on site as opposed to at the workshop. A single cryogenic column, one of the main components of the plant, can weigh up to 170 t and be up to 7 m in diameter and 45 m long, while preassembled coldboxes can be 5 m by 7 m and 40 m long (Linde, n.d.). Lastly, the workshops could be located near the harbour or construction site with some of the welding and final manufacturing taking place at the site.

To date, the relatively small plants have not been limited by engineering, but rather by market size and the lack of need for larger plants. Considering these factors, the investment cost assumed for this study is USD 600/kWH_2 for the *Optimistic* scenario, which would fall close to the middle of the range for LNG, much lower than today but still realistic. The *Pessimistic* scenario assumes USD 1000/kWH_2, which would be at the lower end of cost estimates for 200 t/d (i.e. low-cost estimates for 200 t/d become the high-cost estimates for 2 500 t/d). These costs exclude storage and the terminal, which are estimated separately in this study.

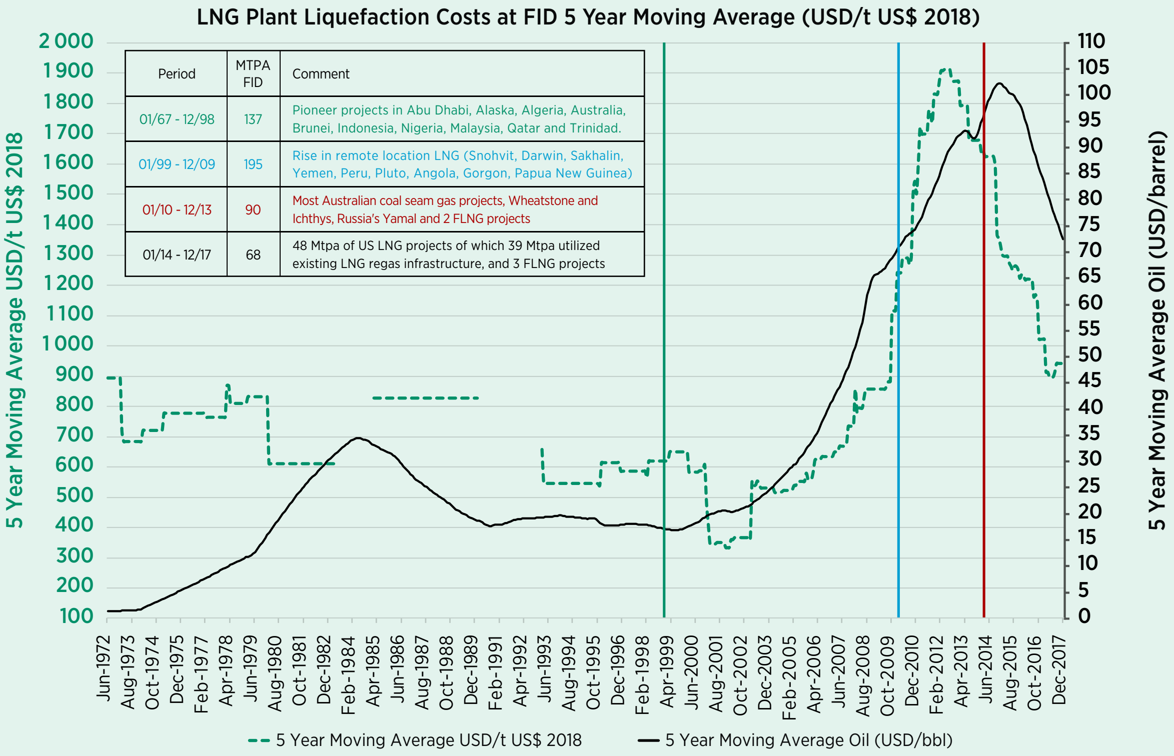
A plant size larger than 1000 t/d could offer possibilities of using new cryogenic refrigeration technologies that rely on centrifugal compressors, which could unlock lower costs by providing further economies of scale (Berstad et al., 2022). Designs with a larger capacity favour the use of a mixed-refrigerant Joule-Thomson Cycle for the pre-cooling and a dual hydrogen and neon cycle for the cryogenic refrigeration (Cardella, 2018). Above 200 t/d for a single train, the coldbox would reach the maximum practical dimensions for transport. Above 500 t/d, the electric motor drives of the compressors would reach the maximum sizes found today. In both of these cases, these limits could be overcome by using equipment in parallel.

Box 3.1. Lessons from LNG for hydrogen liquefaction

LNG is the closest commercial process to liquid hydrogen as it also requires cryogenic conditions (although at a very different temperature level), it is used for global trade and it has already reached a sizeable share of its market. By the end of 2020, global LNG trade represented about 13% of the world's gas production (BP, 2021) and about a third of the LNG is traded on the spot market (heavily concentrated in Asia, especially China) (IGU, 2021b). This, however, has not happened overnight. The first commercial-scale LNG plant was constructed in Ohio (United States) in 1941.[27] In 1956, a large gas field (Hassi R'Mel) was discovered in Algeria, leading to the construction of a 1.5 Mt/yr plant (three trains of 0.5 Mt/yr)[28] in 1964 to export LNG to the United Kingdom and France. By the 1970s, Japan and the United States had joined as importers, accelerating market growth and reaching about 3.5% of global gas production by 1990, 6% by 2000 and 9.6% by 2010. During the last 30 years, peak annual capacity growth has been around 12%, with an average of 6%. By end of 2020, global liquefaction capacity stood at 453 Mt/yr, with 892 Mt/yr in the project pipeline capacity (IGU, 2021a). So, it has taken almost 55 years for LNG to reach its current size.

During this time, the liquefaction capacity of a single train has grown by a factor of 21 (from 0.35 Mt/yr in Algeria to 7.8 Mt/yr of Qatari LNG) (Steuer, 2019). Similarly, project capacity has also increased by a similar factor (1.5 Mt/yr in Algeria to 32 Mt/yr in the North Field expansion project in Qatar). The cost change associated with this capacity increase has been far from smooth, and asymptotically decreasing (see green dashed line in Figure 3.9).

FIGURE 3.9. Five-year moving average of oil prices and LNG plant costs at time of final investment decision



Period	MTPA FID	Comment
01/67 - 12/98	137	Pioneer projects in Abu Dhabi, Alaska, Algeria, Australia, Brunei, Indonesia, Nigeria, Malaysia, Qatar and Trinidad.
01/99 - 12/09	195	Rise in remote location LNG (Snohvit, Darwin, Sakhalin, Yemen, Peru, Pluto, Angola, Gorgon, Papua New Guinea)
01/10 - 12/13	90	Most Australian coal seam gas projects, Wheatstone and Ichthys, Russia's Yamal and 2 FLNG projects
01/14 - 12/17	68	48 Mtpa of US LNG projects of which 39 Mtpa utilized existing LNG regas infrastructure, and 3 FLNG projects

Source: Steuer (2019).

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[27] This plant only operated for three years before an LNG tank failed, causing 130 fatalities, which put the industry on hold until 1959 when liquefaction was used to deliver the first LNG cargo.

[28] Initially with a capacity of 0.35 Mt/yr.

Box 3.1. (Continued)

Between the early 1970s and the early 2000s the cost of liquefaction nearly halved. However, one decade later, the cost more than quadrupled and has not reattained the minimum from the 2000s since then. Distinctive periods are evident in the cost development (Steuer, 2019):

- Initial pioneer projects (1967-1999): This period saw a cost decrease of 12.7% with a cumulative capacity of 137 Mt/yr.
- Growth in remote locations (1999-2010): This period actually experienced a cost increase of 12.5% due to capacity growth in remote locations with limited local energy supply or infrastructure. This period saw cumulative capacity of 195 Mt/yr deployed.
- New large-scale projects with new engineering challenges (2010-2014): This period included projects that were departing from the norm, resulting in new challenges and costs. One example is Prelude, which was the first floating LNG project. This resulted in a cost increase of 19.4% with a cumulative capacity of 90 Mt/yr.
- Building upon existing infrastructure – brownfield projects (2014-2019): This stage included expansion of previous projects that already had the utilities, storage and supporting facilities, reducing the overall cost. This resulted in a cost decrease of 42.6% with a cumulative capacity of 68 Mt/yr.

Another feature of LNG is that some of the early contracts were indexed with the price of oil. This resulted in periods of high oil prices attracting more investment into LNG, leading to higher project costs for access to more difficult resources and more challenging projects. Hence, the historical total project cost for LNG is highly correlated with oil price (see Figure 3.9).

The cost range experienced over the last two decades is USD 400-1 900/tonne, equivalent to USD 1.6-6.5/GJ or about USD 250-1 200/kW. In specific terms, this is much lower than hydrogen liquefaction, which is in the order of USD 2 000-3 000/kW for small plants of 15-30 t/d. Only the lowest estimates of larger-scale plants (200 t/d) attain the USD 1 000/kW level. This cost differential is explained to an extent by the lower temperatures needed for liquefying hydrogen (-253°C vs -162°C). A commercial LNG plant can consume 0.25-0.35 kWh/kg LNG (Pospíšil et al., 2019), which is equivalent to about 1.8-2.5% of the LNG feed,[29] in contrast to the 30-36% for hydrogen liquefaction. Similar differences are observed in train capacities. The largest LNG plant is equivalent to 21 300 t/d of LNG, while a large-scale hydrogen liquefaction plant today is about 40 t/d (even a factor of over 220 remains after correcting for the difference in energy content). This took decades, with the average hydrogen train size increasing by 2 Mt/yr (3.2 GW) every 25 years.

A typical capital cost breakdown for LNG plants is about 45-50% for the refrigeration and liquefaction, 25-27% for the jetty, storage and other offsite facilities, 16-20% for the utilities, and 6-7% for the gas pretreatment (Al-Breiki and Bicer, 2020; Songhurst, 2014) (see Figure 3.10). This means that the costs to consider are not only those associated with liquefaction, but also the supporting equipment, which can be anywhere between 50-100% of the liquefaction costs. Thus, the scope of the project will have a large impact on cost. The lowest cost is for additional trains in an existing plant; this is followed by a full plant on an industrial site (i.e. with a port, accommodation and infrastructure), a new plant on a new site and a new plant with the upstream gas supply (Songhurst, 2014).This will be especially important for projects looking to use remote locations with the best renewable resources. The liquefaction plant could be near the exporting port where presumably the supporting facilities are more developed, but the renewables will still be in a remote

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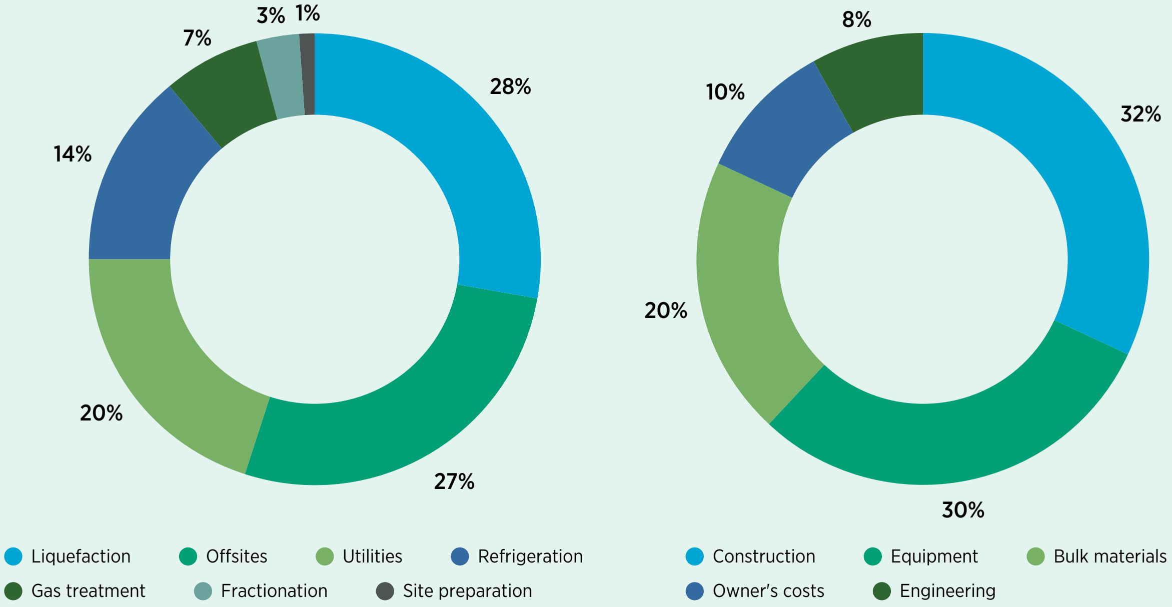
[29] This depends on the specific plant design and configuration and can be 5-6% of the natural gas feed.

Box 3.1. (Continued)

place with the need for an additional pipeline to transport the hydrogen. Given about a third of the total cost is for construction, the cost of domestic labour can also make a big difference. While labour cost is not the only factor, an LNG plant in Australia can be two to three times more expensive than a plant in Qatar (Steuer, 2019).

FIGURE 3.10. Average cost breakdown for LNG liquefaction by plant area (left) and by cost category (right)

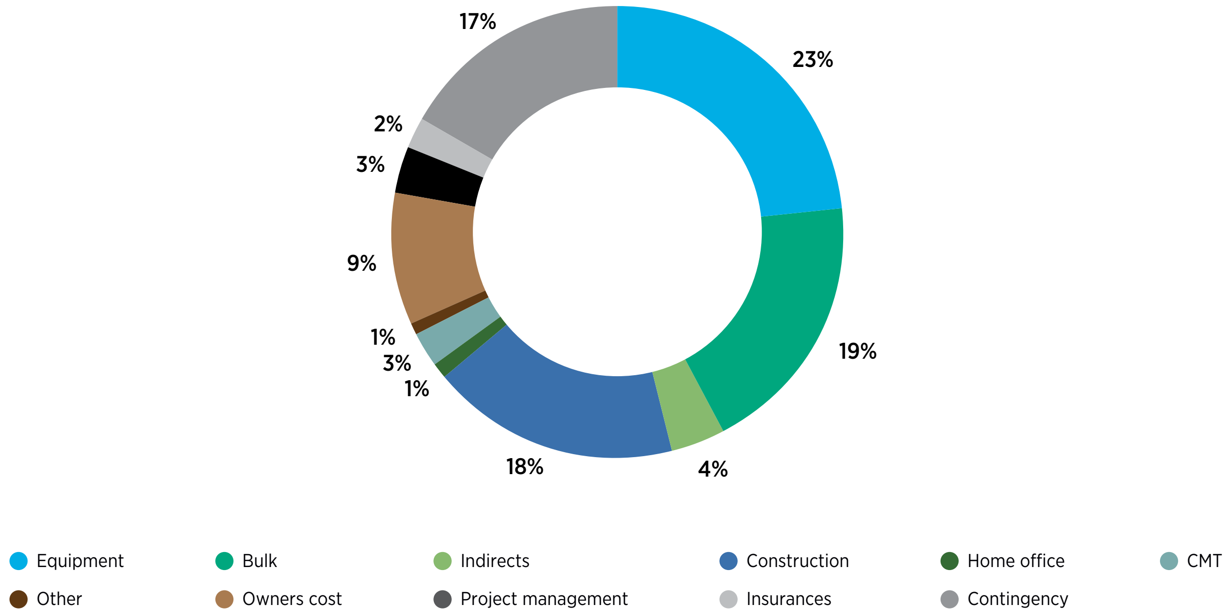


Source: Songhurst (2014).

The second factor in the CAPEX is how it is affected by the project scope. The equipment cost is just the starting point for the total cost estimate and there are multiple items that will increase the cost (see Figure 3.11). This not only highlights the importance of other costs, but also gives insight into some of the factors that might limit a continuous cost decrease as more capacity is deployed (see also Box 3.1):

- Remote locations with limited infrastructure, which increases the costs for pioneer projects that have to make additional investment for a minimum set of facilities.
- Low availability of skilled workforce in instances where industry develops faster than people can be (re)trained and allocated to projects.
- Need for higher salaries to attract people to work in remote locations (mostly for construction and low-skilled workers).
- Uneven growth of the supply chain where some elements represent bottlenecks, increasing the cost of specific components and increasing the overall cost. This could also happen for specific materials (e.g. similar to the price increase during the second half of 2020 and early 2021 for common materials such as steel and copper).

FIGURE 3.11. CAPEX breakdown for a 3 x 200 t/d hydrogen liquefaction facility



Notes: CMT = commissioning management including transport and freight of equipment.
Source: H21 (2019a).

Liquefaction has the advantage of not requiring any toxic components (such as ammonia) or special organic compounds (such as LOHC). It also does not require any critical minerals like PEMFC electrolysers. Instead, the materials used for liquefaction mostly consist of steel and concrete and should not create a limit to scaling up (see Table 3.1).

TABLE 3.1. Estimated material inventory for a 50 t/d liquefaction plant

MATERIAL	MASS (TONNES)
Carbon steel	380
Stainless steel	595
Copper	150
Aluminium	140
Concrete	46 620

Source: IdealHy (2013a).

3.4 Shipping

The only hydrogen ship currently in existence is a 1 250 m^3 pilot vessel (see Section 3.2). The most advanced ship design so far is from Kawasaki Heavy Industries, and has a volume of 160 000 m^3 (Kawasaki, 2021), which means a scale up of 64 times from the pilot is needed. The main considerations to address to enable this growth are similar to those for ammonia: prime mover, regulations and standards, and infrastructure.

Prime mover

Hydrogen can be used in ICEs or fuel cells (see Table 3.2). Fuel cells have the advantage of very low levels of noise, vibration and pollutant emissions, and lower maintenance cost due to no moving parts. Some of their challenges are their tolerance to impurities (e.g. in the air intake), especially for PEMFCs, and shock resistance. Both PEMFCs and SOFCs have an efficiency of about 60%. SOFCs have the additional advantage that they operate at high temperature (700-1000°C), which can be used to produce steam and additional power in steam turbines. This can increase the overall system efficiency to about 80% (Sekkesæter, 2019). For both technologies, additional auxiliary components (i.e. balance of plant) decrease the overall efficiency by a few percentage points. These losses become higher as the fuel cells become larger. SOFCs have a lower specific power (kg/kW) than PEMFCs by a factor of 12.5 and, given their high operating temperature, starting up takes longer and they are less tolerant of load variations. ICEs become more efficient at larger sizes, have a higher average power density and lower cost, are more tolerant to load variations and have a longer lifetime. Some of their disadvantages are the noise and vibration and lower efficiencies.

TABLE 3.2. Comparison between direct hydrogen use in fuel cells and ICEs

	ICE	PEMFC	SOFC	GAS TURBINE
Conversion efficiency (%)	50%	52%	60%	35%
System efficiency (%)	50%	56%	80%	58%
Cost (USD/kW)	< 500	> 1 500	> 4 500	-
Specific power* (kg/kW)	2-11	4	50	1.25-2
Partial load efficiency	High	High	High	Low
Tolerance to load variations	High	Medium	Low	High
Maturity	High	Medium	Low	High
Lifetime	High	Low	Low	High
Noise/vibration	High	Low	Low	High
NO$_x$, CO and hydrocarbon emissions	Medium	Low	Low	Medium

* Specific power is commonly defined as power output (kW) per unit of weight, but the inverse is reported here to give values higher than 1.
Sources: CMB (2019); Sekkesæter (2019); Welaya, El Gohary and Ammar (2011).

Fuel cells have been the preferred choice in the demonstration projects that are ongoing. These, however, are for small ships (e.g. ferry, pusher) with fuel cells that reach up to 600 kW. The current limit for fuel cell size is around 2 MW. To put this into perspective, a commercial liquid hydrogen ship would require at least 5 MW of power. The other type of demonstration project is for international trade (see Section 4.2), where there are no examples using hydrogen as fuel.

Regulation

Hydrogen is not currently included in the IGF Code or IGC Code. Since HySTRA has been the only demonstration so far, and it uses diesel as fuel, the process has been to attain approval under the IGC Code first, with the IGF Code application expected in the next few years. The IGC Code is more flexible as an agreement between port administrations (and the IMO) based on a provisional assessment is enough at least for interim approval (IGC Code 1.1.6). The application process started in December 2014, with the interim guidelines for carrying hydrogen being adopted in November 2016. As a reference, LNG took six years between the first interim guidelines and the final adoption of the code. The Sub-committee on Carriage of Cargoes and Containers is also working on interim guidelines for the safety of ships using fuel cells, which would be used to amend the IGF Code. These draft guidelines, however, detail only the provisions for fuel cell installations and not the storage or use of hydrogen as a fuel.

As regards classification societies, the International Association of Classification Societies carried out a hydrogen risk assessment in August 2016 (IACS, 2016), which is one of the key requirements for approval as a fuel under the IGF Code. Class NK, one of the leading classification societies, released guidelines for construction and operation of liquid hydrogen carriers in 2017 (ClassNK, 2017). Lloyd's Register has given approval for hydrogen use in fuel cells for small ships, such as the Hydroville project (a passenger vessel), but not for large ships to date. It has also granted an AiP for a dual-fuel 1 MW engine. ABS published rules for the use of fuel cells in marine vessels following the interim guidelines and has also issued an initial assessment of the safety, regulatory and design considerations for hydrogen use in ships (ABS, 2021b).

There are also various international and national standards to be considered during the design of liquid hydrogen carriers, as listed in the Appendix: International and national standards to be considered during the design of liquid hydrogen carriers (ABS, 2021b).

Infrastructure

New facilities need to be developed. Brownfield projects located at existing LNG plants could reduce the cost of hydrogen liquefaction as some of the equipment could be used. For example, the Brayton cycle compressor operating with nitrogen that is used in some LNG processes could be used for the initial cooling of the hydrogen (Alekseev, 2016). This would be good enough to achieve temperatures of -190°C, but a new expansion and cooling system will always be needed for the lowest temperature range (up to -253°C). Chart Industries (a provider of LNG technology) claims that modifying existing LNG infrastructure for hydrogen could lead to 50-60% lower costs than building new infrastructure (NGI, 2020). A potential saving may also be available by retrofitting existing LNG storage tanks. One option is to attach membrane insulation panels to the inside of the storage tanks. Another (more expensive) option is to install a new vacuum-insulated storage tank inside the existing concrete construction. There could also be savings in the common equipment and supporting utilities if a terminal has both LNG and hydrogen liquefaction.

This opportunity to repurpose would take advantage of the 42 locations that liquefy LNG (several of these with multiple trains, and another 11 locations under construction) and 133 receiving terminals around the world (IGU, 2021a). Box 3.2 shows some of the aspects of LNG shipping that can provide a useful reference for liquid hydrogen.

Box 3.2. Lessons from LNG for liquid hydrogen transport

Experience from LNG transport can be useful to put the numbers for hydrogen into perspective and give a sense of the scale that hydrogen ships could reach. The first LNG tankers were the *Methane Princess* and the *Methane Progress*[30] in 1964 (same specification for both ships), with a capacity of 27 400 m^3 (GIIGNL, 2014). By the end of 2020, the largest LNG tanker was the Mozah QMax LNG with 266 000 m^3. If a hydrogen carrier were able to handle the same volume, it would be the equivalent of almost 19 000 tH_2. For LNG, the market is settling on an average size between 170 000 m^3 and 180 000 m^3, which coincides with the size limits for the new Panama Canal expansion (Steuer, 2019). A lesson for liquid hydrogen is the size ratio between the initial ships and the latest, which is a factor 10. This contrasts with the almost 130 times that would be needed to go from the current largest demo ship of 1 250 m^3 to the commercial scale of 160 000 m^3.

The global LNG trade was 356 Mt in 2020 (IGU, 2021a). This is equivalent to 16 Exajoules (EJ) or about 3.9% of total final energy demand in 2020. This was achieved with a global LNG fleet of 572 vessels. LNG vessels can use boil-off gas, diesel or heavy fuel oil to power them. Of the current fleet, 40% use steam turbines, which have fuel flexibility but low efficiency (35%), resulting in the technology being phased out. Newer ships use dual-fuel generators that drive electric motors, which increases the efficiency by up to 30% compared to steam turbines. These represent about a third of the current fleet. Other technologies are slow-speed dual-fuel and slow-speed diesel with re-liquefaction. The average delivery time for an LNG carrier is 30-50 months (IGU, 2021a). Like hydrogen, depending on the size of the storage tanks and vessel's speed, the boil-off gas might not be enough to propel the ship. Boil-off rates for LNG are 0.1-0.15% per day for large ships and 0.2-0.6% per day for smaller ships (with a higher surface-to-volume ratio) (Al-Breiki and Bicer, 2020; Kim et al., 2019). There are multiple ways to deal with the boil-off, from flaring (Liu et al., 2010) to its use for steam generation and re-liquefaction (Romero Gómez et al., 2015). With these boil-off rates and all the additional costs (e.g. canal fees), the total transport costs for LNG are equivalent to about USD 0.03/kgH_2 per every 1 000 km (see Figure 6.7). This would be equivalent to the best case for hydrogen liquefaction (0.1% per day) without the additional costs (only the cost of the vessel), noting that items such as labour, insurance, port fees and others can be about 50% of the operational cost (Al-Breiki and Bicer, 2020).

Lessons for liquid hydrogen from the above include the long delivery time for commercial carriers (2.5-4 years), which needs to be considered during the planning of global trade projects. Similarly, it has taken more than 55 years from the first LNG carrier to reach a global fleet of 572 vessels. If the global liquid hydrogen fleet were to reach the same size, it would hold about 6.5 MtH_2[31] (about 1% of the expected 2050 global annual demand).

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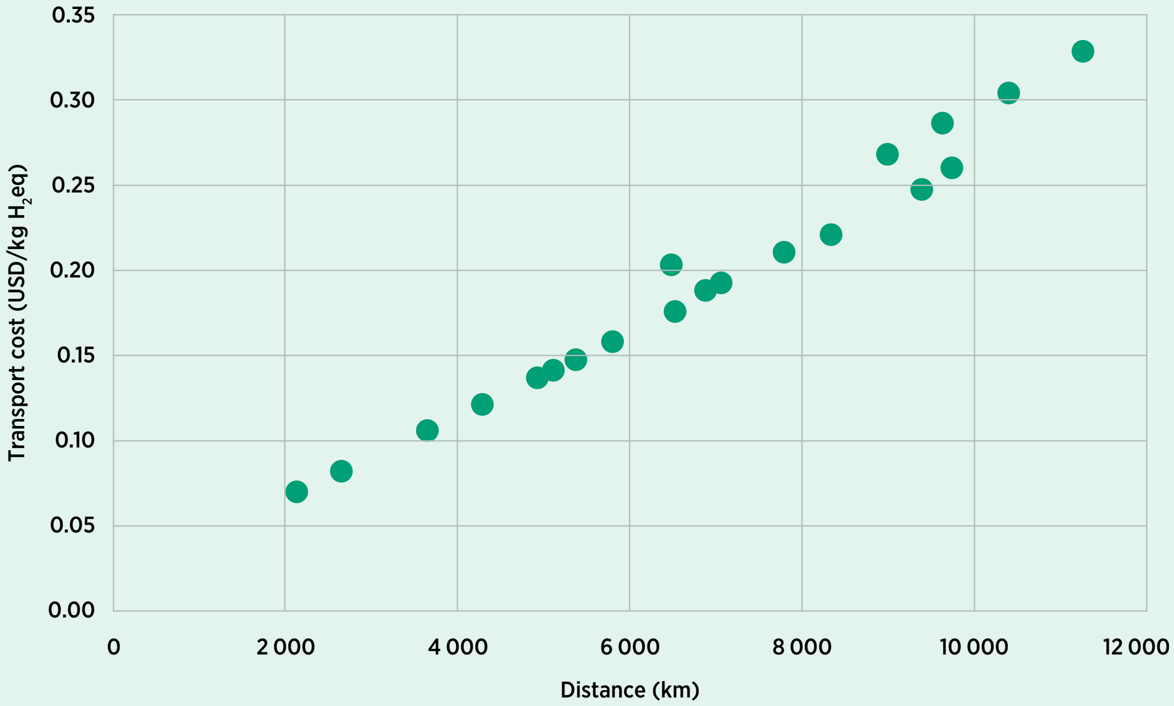
[30] There were LNG ships before these (e.g. Methane Pioneer), but those were cargo ships converted to LNG carriers.

[31] Assuming a volume of 160 000 m^3 per carrier.

Box 3.2. (Continued)

FIGURE 3.12. LNG transport cost expressed in hydrogen equivalent



Notes: Costs are converted to hydrogen equivalent using the LHV of hydrogen. This is done to put values on a scale that can be easily compared with other costs in this report, but they do not represent hydrogen transport costs.
Source: (Steuer, 2019).

When looking at the cost of LNG storage at the terminal, tanks have a typical investment cost of USD 30-40/kg for tanks above 100 t and USD 80-100/kg for smaller cryogenic tanks (NCE, 2016). The largest LNG storage tanks at terminals in Europe are in France (Dunkirk) with an individual capacity of 200 000 m^3, while the largest tank farm is 1 million m^3 in the United Kingdom (Isle of Grain) (GIE, 2019).

There are three types of bunkering for LNG ships: ship-to-ship, tank truck to ship, and terminal (from a storage tank) to ship using a pipeline. However, the first two are better suited to small volumes (up to 100-200 m^3) and only a pipeline from storage is suitable for large volumes and high transfer rates (DMA, 2012). For this option, the storage tanks need to be close to the berths where bunkering is performed. These pipelines require vacuum jacketing and their design needs to consider layout (space), safety and other terminal activities. This is standard practice for liquid nitrogen and LNG systems. For large hydrogen flows, there might be a limitation on the current valve and pipe sizes, but this can be overcome by allowing higher pressure drops (which are small for liquid hydrogen) or installing parallel valves (which is standard practice in cryogenic helium plants).

Other components, such as bunkering facilities and transport to and from the port, would have to be new as they cannot be adapted from LNG. The specific location of the bunkering facilities is defined according to multiple criteria (see Table 3.3). The cost of the jetty and terminal is taken as EUR 54 million for a 225 ktH_2/yr plant (Raab et al., 2021) and scaled according to the project capacity. Using this assumption, the cost contribution is equivalent to about 10% of the liquefaction plant.

Liquid storage tanks

At the terminal, liquid storage tanks are needed as buffers between the liquefaction plant (outgoing) and regasification plant (incoming) and the ships, since it is a transition from a continuous to a batch process. During the transfer operation between the ship and the storage tank, some of the liquid hydrogen can be expected to gasify due to unavoidable temperature fluctuation. This can be 1.2-1.3% of the transferred quantity for each operation (Wijayanta et al., 2019) (although it can be as high as 5% for smaller volumes (US Drive, 2013)). Furthermore, boil-off from the storage tank is 0.05% per day (*Optimistic*) to 0.25% per day (*Pessimistic*).[32] These streams can be re-liquefied and returned to the storage tank at an additional energy penalty. The energy penalty for this is relatively small (in the order of 0.1-0.15 kWh per kgH_2 per day that needs to be re-liquefied, which is in turn a fraction of the total hydrogen flow), as it is already a cold stream (below -240°C) and the energy input is only the latent heat of vaporisation (Petitpas, 2018). The use of integrated refrigeration and storage (IRAS) heat exchangers can lead to no boil-off losses by using an internal coil with cryogenic refrigeration using helium (NASA, 2021a). The CAPEX for this system can be equivalent to about 5-7% of the storage tank cost and can achieve a payback time of less than a year for a 40 000 m^3 tank with a boil-off rate of 0.06% per day (NASA, 2021b).[33]

TABLE 3.3. Port criteria for liquid hydrogen bunkering (adapted from LNG)

CATEGORY	PARAMETER	DESCRIPTION
Economic	Investment cost	Investment needed for adapting quays, fairways and berths
	Operational cost	Staff costs, bunkering fee, port fees and fairway dues
	Incentives	Including financing schemes and measures to compensate for higher risk
Technical	Vessel dimensions	Length, beam, maximum draught, speed, manoeuvrability and traffic density
	Storage	Capacity, connections and transfer rate
	Access to gas grid	To reduce the need for additional pipelines from/to port
	Land availability	For jetty and terminal
Logistical	Layout	Ability to anchor and protected anchorage spaces for bunkering
	Manoeuvrability	Carriers to be able to perform different manoeuvres without constraints
	Fairways	Depth, width, speed limitations, wind, waves, currents, navigational aids, bank clearance, turn radius, tides and visibility, among others
Safety	Separation of activities	Separation of hazardous activities and liquid hydrogen
	Mooring	This can affect safety in combination with port/basin layout

Source: DMA (2012).

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[32] These are still conservative since experience from NASA at Cape Canaveral indicates losses could be as low as 0.03% per day (NCE, 2016)

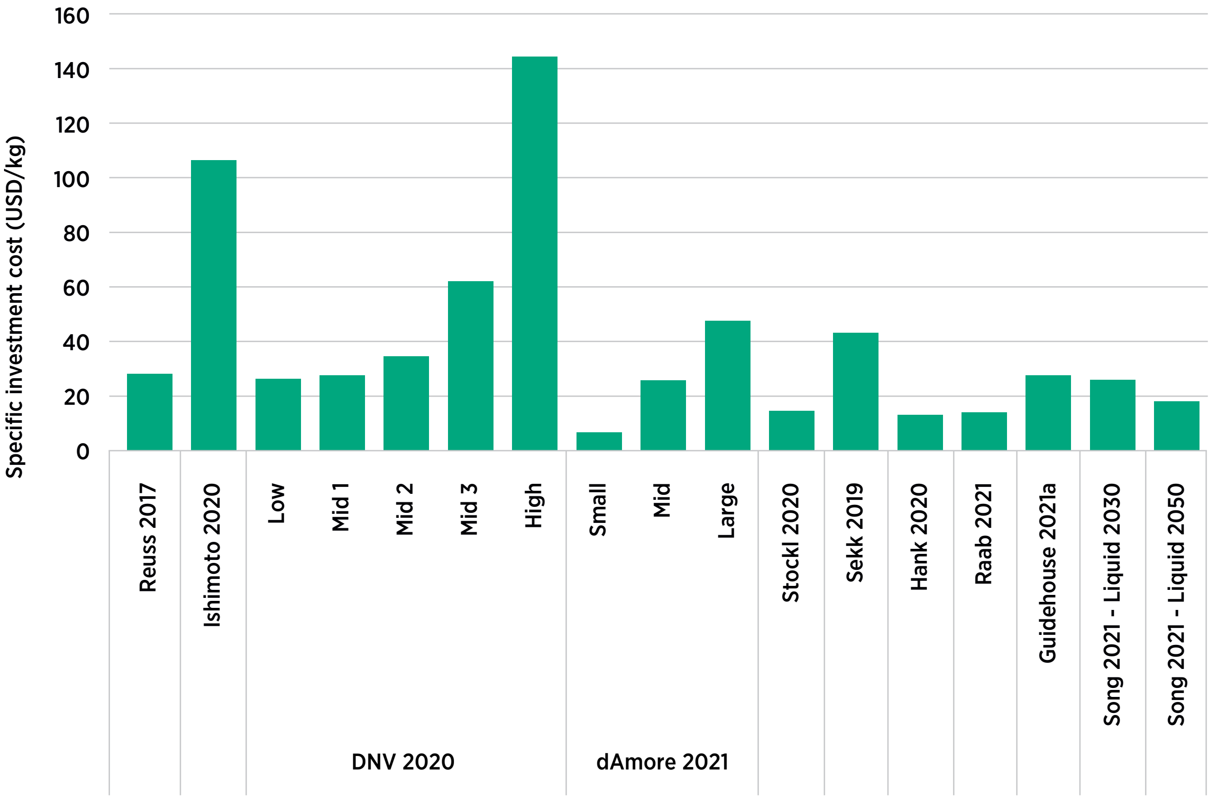
[33] With a hydrogen price of USD 6.25/kgH_2 and an electricity price of USD 120/MWh.

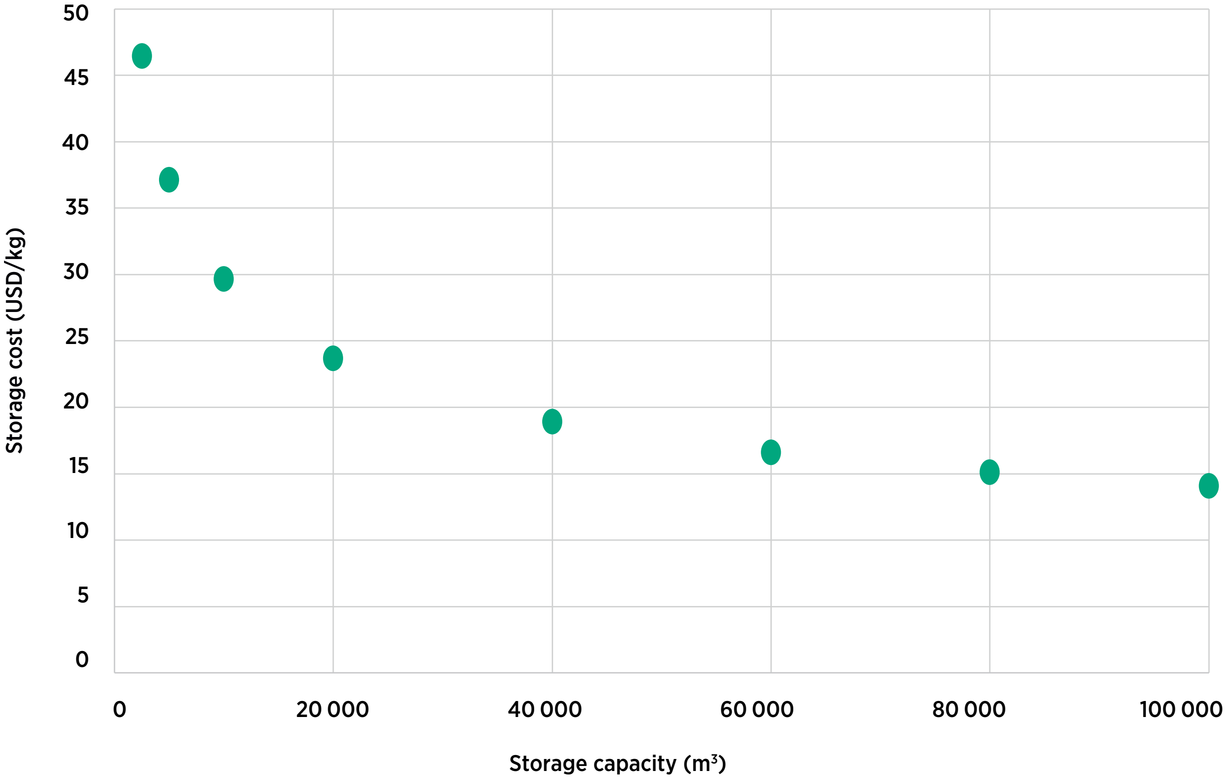
Storage tanks at each terminal are sized according to the maximum of two values. First, each tank should be at least the size of a single ship to ensure that when the ship arrives in port it can be completely filled with the storage inventory. Having smaller tanks would mean the ship needs to stay docked while the production of the liquefaction plant fills it, which would lead to idle time and a higher cost contribution from the ship. Second, each tank must be able to store at least one week of equivalent production from the liquefaction plant to avoid too frequent a turnover. For long-distance routes (e.g. Chile to Japan) that require dozens of ships combined with a large scale (> 5 MtH_2/yr), the capacity of a single ship might be equivalent to one day of liquefaction capacity. For operational flexibility and to avoid too frequent a turnover of the inventory, a minimum of one week of storage is assumed. Even with these criteria, storage represents less than 15% the cost of liquefaction.

Liquid hydrogen storage tanks need to be well insulated due to the low boiling point of hydrogen. Most hydrogen storage vessels are double-walled with a vacuum between. This space between can also contain additional materials such as alumina-coated polyester sheets, alternating layers of aluminium foil and glass fibre; or aluminium, silica or perlite particles. The vacuum is intended to reduce losses via conduction and convection, while the alternating layers aim to reduce losses via radiation (Andersson and Grönkvist, 2019). The heat losses can also be reduced by decreasing the ratio of exposed surface to volume of the tank and that is why spherical tanks are used to store liquid hydrogen. There is a trade-off with cost. Cylindrical tanks have a higher surface-to-volume ratio than spheres, but are easier to manufacture (i.e. lower cost), which makes them more common. The boil-off ratio depends on tank size and intended usage pattern. For example, small tanks of 300 m^3 can have boil-off ratios of 0.3% per day, while tanks of 1100-2 300 m^3 can already achieve rates of less than 0.1% per day (Berstad et al., 2022).

This complex design results in a storage capital cost of about USD 15-45/kg (see Figure 3.13). The highest cost estimate from Figure 3.13 is for a relatively small tank of about 4.3 t of LH_2 (SNL, 2016). In contrast, a commercial tank is expected to be much larger. The HySTRA project considers a ship with individual tanks of 40 000 m^3 and it envisages storage of 50 000 m^3 at the importing terminal. The US Department of Energy allocated USD 6 million of funding (complemented by USD 6 million of private funding) to demonstrate storage at a scale of up to 100 000 m^3 targeting a boil-off rate of 0.01-0.01% per day, a CAPEX below 150% of LNG storage cost, and including safety and regulatory aspects. The project runs until 2024, and includes model validation and the construction of a demo tank. Construction of these large tanks can take at least 3-5 years. Another cost outside the USD 15-45/kg range is from Ishimoto et al. (2020) at almost USD 100/kg (see Figure 3.13), where the difference is explained by the use of spherical tanks (instead of cylindrical). There is also uncertainty in the behaviour of cost as the scale increases. The scaling exponent (i.e. cost change with capacity) ranges from 0.67 (Ishimoto et al., 2020; Raab et al., 2021) to 1 (Reuß et al., 2017; Stöckl et al., 2021) or even values above 1 (1.344 from d'Amore-Domenech, Leo and Pollet [2021]). For this study, a 0.67 scaling exponent was used, with the lowest cost for 2050 assumed to fall to USD 15/kg. This cost range is also in line with the *Ultimate* target from the US Department of Energy (DoE, n.d.). Large storage volumes favour not only the cost, but also the heat losses, as it improves the surface-to-volume ratio.

FIGURE 3.13. Specific CAPEX of liquid hydrogen storage and uncertainty from literature





Sources: DNV (2020); d'Amore-Domenech, Leo and Pollet (2021); Guidehouse (2021a); Hank et al. (2020); Ishimoto et al. (2020); Raab et al. (2021); Reuß et al. (2017); Sekkesæter (2019); Stöckl et al. (2021).

Even with the complex insulated design of liquid hydrogen storage tanks, the higher energy density compared to compressed gaseous hydrogen storage tanks predominates, resulting in a lower specific cost. Liquid hydrogen is about 80% denser than compressed hydrogen at 700 bar. However, because of the high pressure, more steel per kilogram of hydrogen is needed for gaseous storage (about 23-24 kg of steel per kg of hydrogen for 700 bar vs about 9 kg/kg for liquid hydrogen) (SNL, 2016). This makes gaseous storage more expensive at USD 300-1 200/kg (Carr et al., 2014; Karellas and Tzouganatos, 2014; Katikaneni et al., 2019; Weinert, 2005).

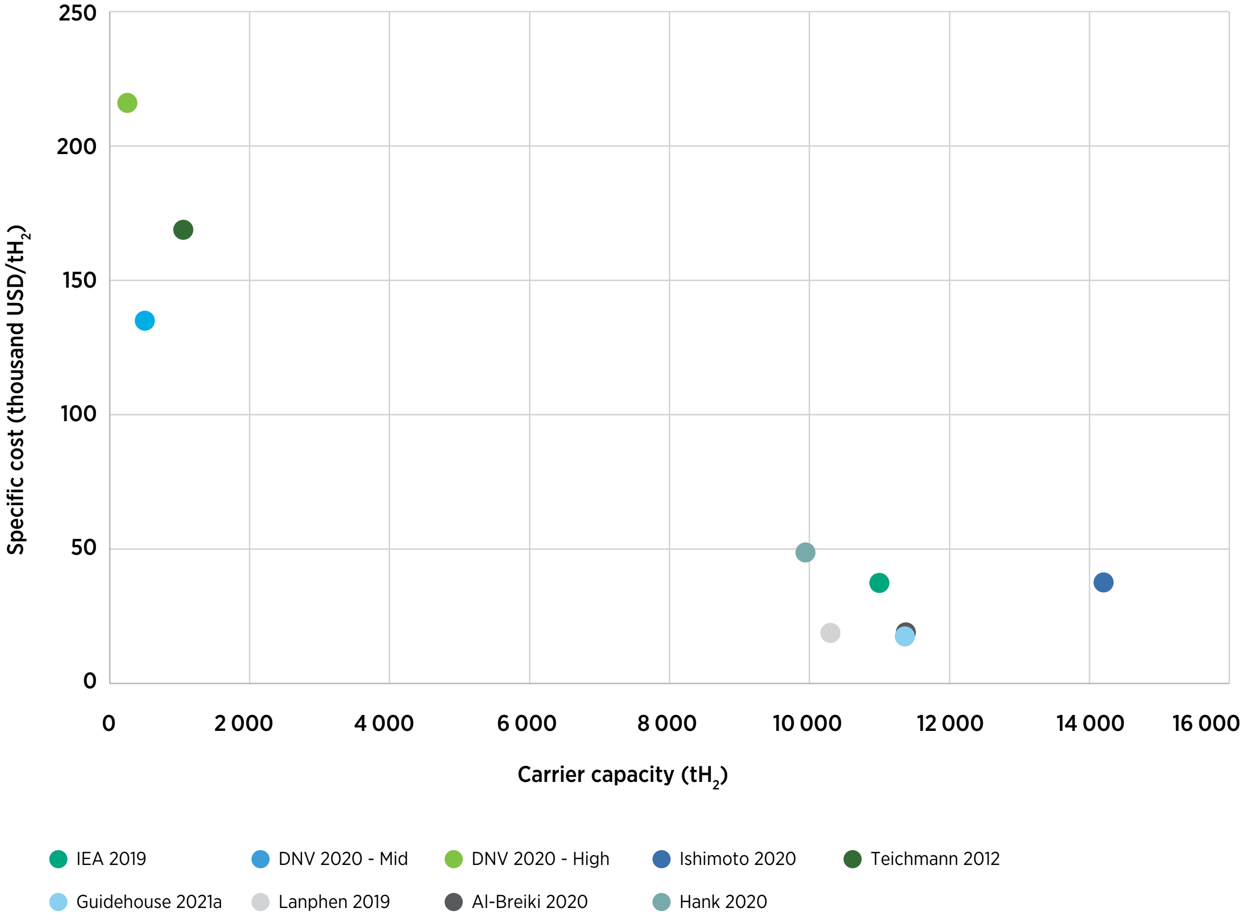
Other terminal components

Other components at the terminals are the piping manifold and the loading arms. The costs for these components are approximated based on LNG. For an equivalent capacity of 4 t/d of liquid hydrogen, the cost of LNG bunkering is estimated to be USD 550 000 (DMA, 2012). For liquid hydrogen, the pipes need to be vacuum jacketed, which makes them more expensive (by a factor of five to ten) (SNL, 2016). Considering that the piping is about 10% of the total cost, the total cost for liquid hydrogen would be USD 770 000. The lower temperature of liquid hydrogen (vs LNG) also requires pre-cooling the lines, prolonging the time needed for bunkering. A 1 t fill may take 40 minutes for cool-down, 30 minutes for transfer and 30 minutes for purge and warm-up (NCE, 2016). Pre-cooling could also be done before the vessel arrives in port. Hydrogen liquid pumps also need to be scaled up to be able to handle the rates that are needed for global trade. Current liquid hydrogen turbopumps have a capacity of up to 30 t/hr (Cryostar, n.d.) and are expensive, while commercial tanks would be in the order of 11 000 dwt (SNL, 2016). In the case of LNG, loading a 160 000 m^3 carrier can take about a day (Rogers, 2018).

Ship specification

One of the main cost components is the CAPEX of the ship (see Figure 6.8). This cost is a strong function of the ship size. For smaller ships, the specific cost can be over ten times that of low-cost estimates for larger ships. Large-scale ships are expected to be in the > 10 000 dwt range (e.g. if liquid hydrogen carriers achieve the same size as today's LNG carriers, they would transport about 12 000 dwt). Within this large-scale range, there is still uncertainty of a factor 2.5. On the low side, Al-Breiki and Bicer (2020), Guidehouse (2021a) and Lanphen (2019) estimate a cost of USD 17 000-19 000 per tonne of hydrogen for a 10 300-11 300 dwt ship. In contrast, Hank et al., 2020 estimate USD 49 000 for an 11 400 dwt ship. To capture this uncertainty, while still being conservative, the range used for this study is USD 35 000 and USD 50 000 per tonne of hydrogen for the *Optimistic* and *Pessimistic* scenarios respectively. On an energy basis, this is equivalent to about USD 290-420/GJ, which would be 3-7 times higher than the specific cost for LNG carriers (Fikri et al., 2018; Rogers, 2018).

FIGURE 3.14. Specific investment cost for a liquid hydrogen carrier as a function of ship size



Sources: Al-Breiki and Bicer (2020); DNV (2020); Guidehouse (2021a); Hank et al. (2020); IEA (2019a); Ishimoto et al. (2020); Lanphen (2019); Teichmann, Arlt and Wasserscheid (2012).

The other main cost component for the ship is energy consumption. The boil-off from storage can be used as a fuel to drive the engine or fuel cell. This, however, is a fine balance. The fuel consumption is a function of the power of the engine and the ship speed. The relationship is non-linear, resulting in large increases in fuel consumption with small increases in speed. At the same time, the power needed to propel the ship is a function of the weight, which will be different for the laden and ballast journeys. The boil-off from the tanks is a function of the stored hydrogen, which means it is also different for each journey. This results in a very specific speed at which the boil-off is exactly the fuel needed to drive the ship. Higher speeds will require gasifying additional hydrogen and lower speeds will require re-liquefying the boil-off. In the case of very low speeds (e.g. approaching the terminals), the energy consumption is actually higher than at higher speeds due to the energy requirement of the onboard re-liquefaction (Sekkesæter, 2019).

Manufacturers of commercial hydrogen ships are targeting cargo capacities of 11 000-12 000 tH_2. This would be lower than the 60 000 t for a typical ammonia carrier or the 110 000 t for an LOHC tanker. The lower weight can translate into lower energy consumption. At the same time, fuel cells can have slightly higher efficiencies (especially when using high temperatures and heat recovery). These factors lead to a lower fraction of the hydrogen being consumed during the journey for liquid hydrogen. A 20 000 km journey would consume about 3.3% of the cargo, which is 17% lower than the amount an ammonia ship would consume. Depending on the ship size and design, the fuel consumption as a share of the cargo can be as high as 12.5% (Teichmann, Arlt and Wasserscheid, 2012).

With a cargo capacity of 11 000-12 000 tH_2, a large number of ships would be needed to ensure a stable flow. For example, Kawasaki Heavy Industries aims to build 80 hydrogen carriers to import 9 MtH_2 to Japan by 2050 (presumably for a 9 000 km journey from Australia to Japan). As a point of reference (see Box 3.2), 572 LNG vessels were used in 2020 to globally trade the equivalent of 134 MtH_2 over the entire year. An additional consideration for liquid hydrogen is that some cargo needs to be left in the tank for the ballast journey, even if the ship is powered by another fuel. This is for tank cooling purposes, similar to the heel of LNG tankers, to keep the tank cold and ready for the next cargo. This can be in the order of 5% of the cargo.

There is limited information on the specific design specifications of the ships, but one example is the 1 250 m^3 carrier from Kawasaki (see Table 3.4). The anticipated berth requirements for hydrogen ships is expected to be a channel depth of 14.2 m, berth pocket size of 350 m by 9 m, depth alongside of 15.7 m, and a maximum length of 300 m, for an 80 000 t deadweight[34] carrier (ARUP, 2019).

TABLE 3.4. Specifications for a 1 250 m^3 liquid hydrogen carrier

COMPONENT	PARAMETER	SPECIFICATION
Ship	Dimensions	110 m x 20 m x 11 m
	Gross tonnage	8 000 t
	Propulsion system	Diesel electric
	Speed	13 knots
Cargo	Tank type	Suitable for pressure vessels
	Design pressure	0.4 MPa
	Insulation	Vacuum multi-layer insulation
	Boil-off gas management	Pressure accumulation

Source: ClassNK (2019).

3.5 Reconversion (gasification)

The major energy requirement in the liquid hydrogen value chain is for liquefaction and transport. During regasification, hydrogen goes back to its natural (gaseous) state, requiring limited effort. All the energy that was put into the hydrogen to make it cold is released, and in most cases, wasted. The hydrogen is simply heated up with seawater or air. This can be done in open rack vaporisers, shell and tube vaporisers, or intermediate fluid vaporisers with some additional cost due to the cryogenic conditions and corrosivity of seawater. For LNG, more than 95% of facilities use seawater (Agarwal et al., 2019).

Hydrogen is transported at low pressure (1-4 bar) while transmission pipeline requirements are usually 70-100 bar. Achieving this pressure increase is much easier with liquid hydrogen than with gaseous hydrogen. For example, pumping gaseous hydrogen from 3 bar to 700 bar (for use in a car) requires about 1.2 kWh/kg (Petitpas, 2018), while reaching the same pressure ratio

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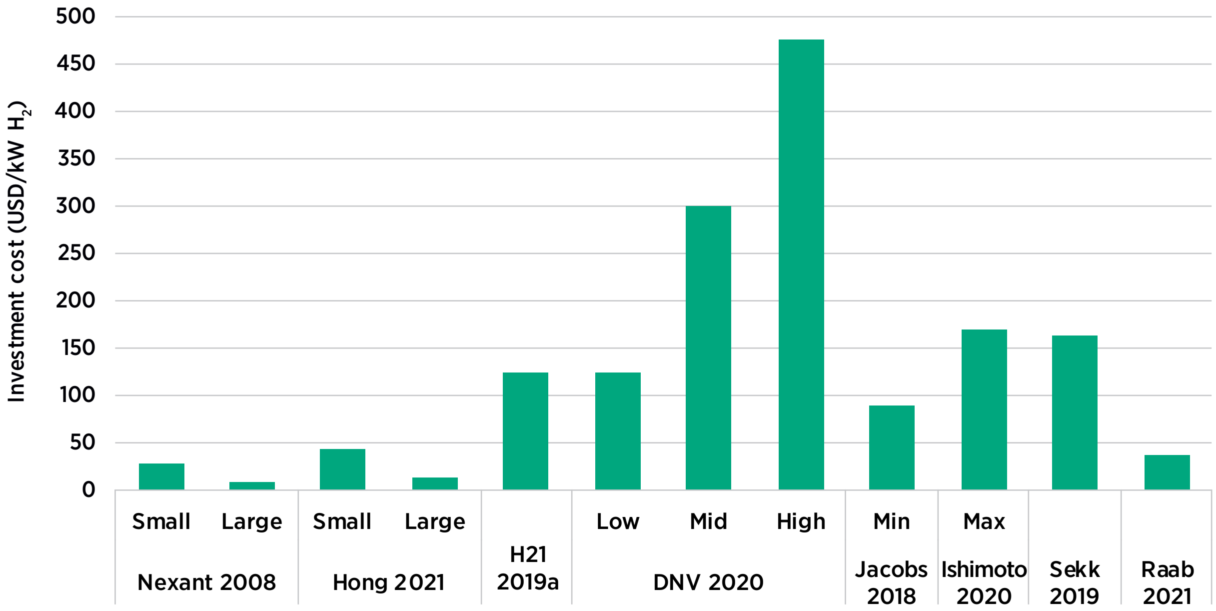
[34] Commercial-scale carriers could be much smaller than this, with a 160 000 m^3 carrier being equivalent to about 11 400 t of hydrogen cargo

with a compressor would consume about 3.8-4 kWh/kg. If the liquid hydrogen is ultimately needed as a gas, another option is to just regasify the liquid hydrogen at a constant volume, with the gasification providing the pressure increase and avoiding the need for pumping.

Regasification costs comprise the evaporators and associated equipment (i.e. pumps or fans), the liquid hydrogen pump, storage and other auxiliary equipment. Despite the simple design, there is relatively large uncertainty in the costs (see Figure 3.15).

FIGURE 3.15. Specific investment cost of liquid hydrogen regasification

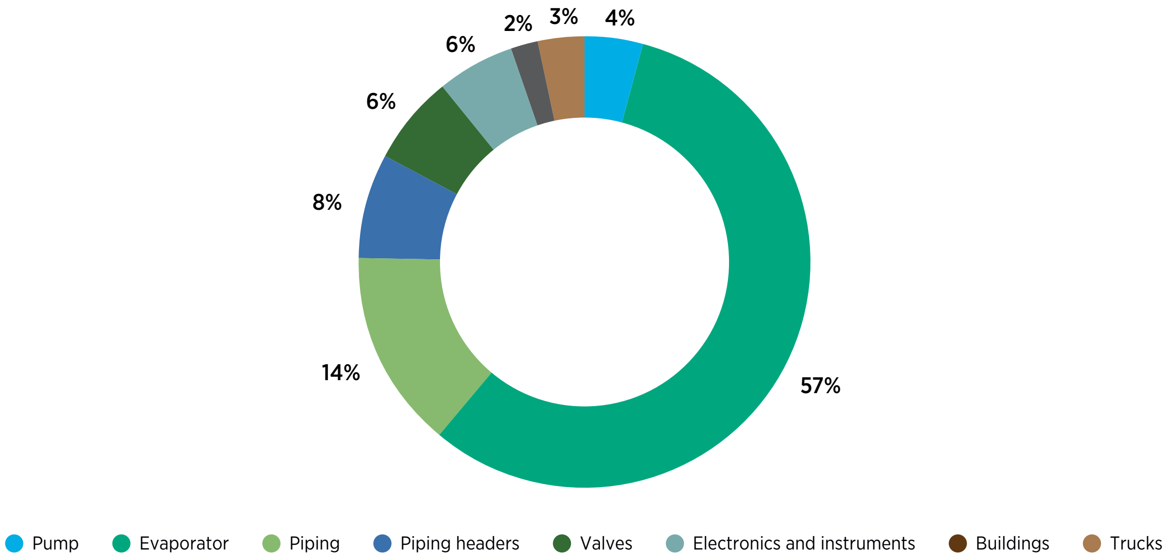


Sources: DNV (2020); H21 (2019a); Ishimoto et al. (2020); Jacobs (2018); Nexant Inc. (2008); Raab et al. (2021); Sekkesæter (2019).

A large part of the cost differential is explained by the scale, while another part is explained by the scope of each estimate. The highest cost estimate of USD 475/kWH_2 corresponds to a plant size of only 10 t/d (DNV, 2020). The cost decreases by two thirds by increasing the plant size to 850 t/d. To put this into perspective, single liquefaction trains are currently up to 34 t/d (see Section 3.3), but are expected to scale up multiple times to support global trade. For consistency with the liquefaction plant, a size of 2 500 t/d is assumed for regasification as well. A further reference is that by February 2021 there were 163 LNG regasification terminals around the world with a cumulative capacity of 850 Mt/yr (IGU, 2021a). This equates to about 9.5 GW of capacity per terminal, or the equivalent to about 7 000 t/d of hydrogen regasification capacity. Therefore, if it is expected that hydrogen reaches at least the scale LNG has today, the assumed 2 500 t/d of capacity is still conservative and further cost reductions by scaling up could be possible.

On the low side of the cost estimates, the cost from Nexant Inc. (2008) only includes the evaporators. As can be seen from Figure 3.16, this is only part of the total cost. Figure 3.16 excludes the main cost component of the importing terminal, which is the storage tanks. These follow similar criteria to the ones at the exporting terminal (at least able to handle the entire cargo of a single ship and avoid overly frequent turnover). According to a tool by the US DoE, storage could represent up to 95% of the total cost of all equipment required at the importing terminal (ANL, n.d.). Using this input, the *Optimistic* scenario assumes a value of USD 65/kWH$_2$ excluding storage and USD 165/kWH$_2$ for the *Pessimistic* scenario. As a reference, the total capital cost for regasifying LNG has been estimated to vary in the range of USD 50-100/kW (Chicago Bridge & Iron, n.d.). In HySTRA (pilot project), the cost of the receiving terminal in Kobe (Japan) is USD 83.5 million.

FIGURE 3.16. Cost breakdown for a 150 t/d liquid hydrogen terminal (excluding storage)0



Source: ANL (n.d.).

The energy consumption of the terminal is composed of the liquid hydrogen pump, the pumps for the seawater and other minor equipment. An estimate of 0.2 kWh/kgH$_2$ is used for the *Optimistic* scenario. The range of uncertainty in literature is shown in Table 3.5. Despite the wide range, this would still be much smaller than the 10-12 kWh/kg for liquefaction or the more than 12 kWh/kg of energy required for ammonia cracking and LOHC dehydrogenation.

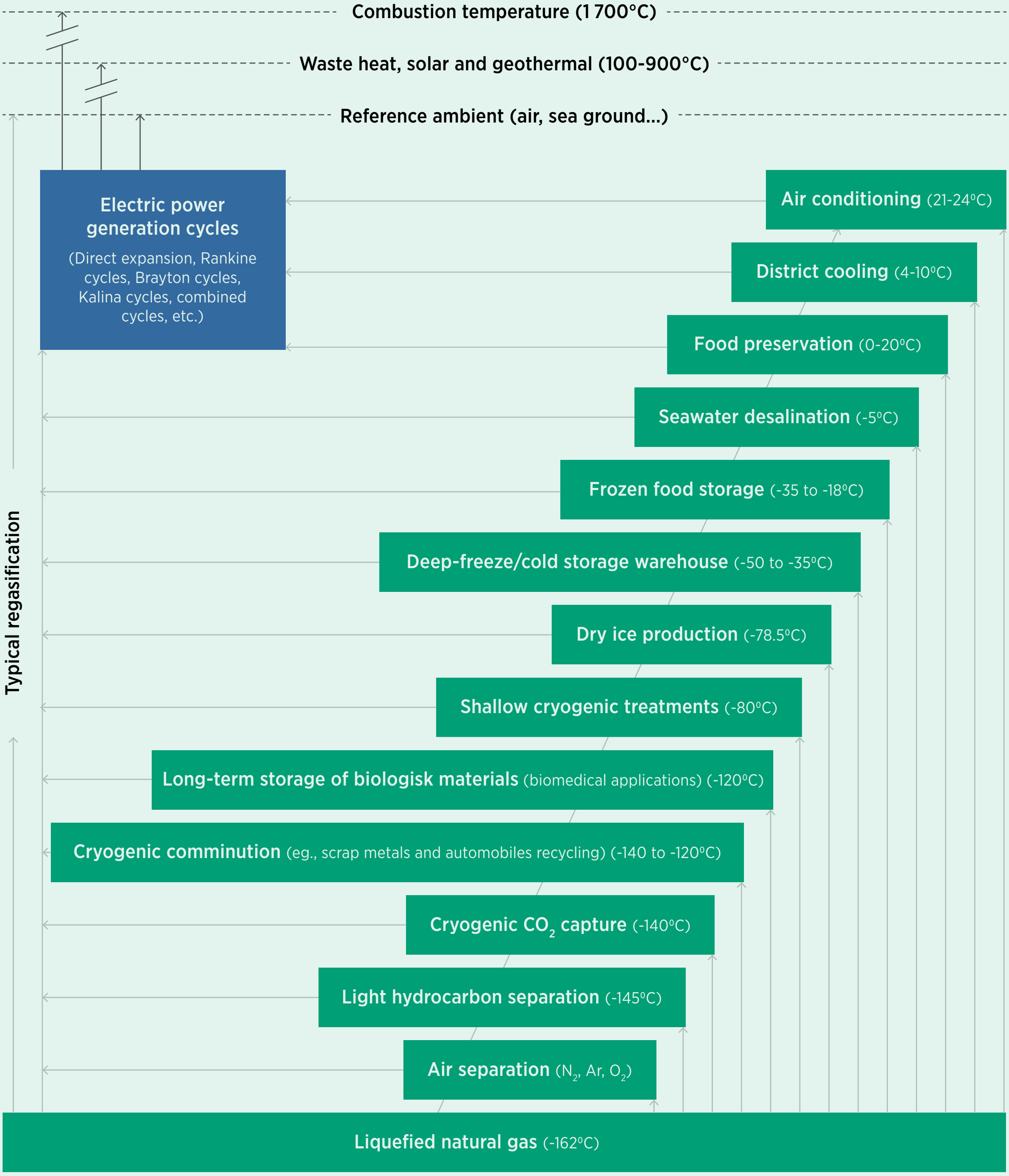
TABLE 3.5. Energy consumption for liquid hydrogen regasification

REFERENCE	ENERGY CONSUMPTION (kWh/kgH$_2$)
Reuss et al., 2017	0.6
Wijayanta et al., 2019	1.665
IEA, 2019a	0.2
Ishimoto et al., 2020	0.182
Sekkesæter, 2019	0.03
Guidehouse, 2021a	0.1

Box 3.3. Lessons from LNG for cold recovery

While most LNG is simply gasified using seawater, several options have been studied to use the energy for cold applications. The temperature level is higher for LNG (-162°C vs -253°C), but there are limited applications for the lowest temperatures that liquid hydrogen achieves, so applications suited to LNG could also be applied to hydrogen. One alternative application would be to use the cold from the hydrogen for LNG liquefaction or vice versa, (Riaz et al., 2021) but that would probably be uncommon in reality since countries importing liquid hydrogen are not likely to be exporting LNG (or vice versa). Figure 3.17 shows some of the potential applications for the cold and the typical temperature ranges.

FIGURE 3.17. Temperature levels for applications that can use the cold from LNG regasification

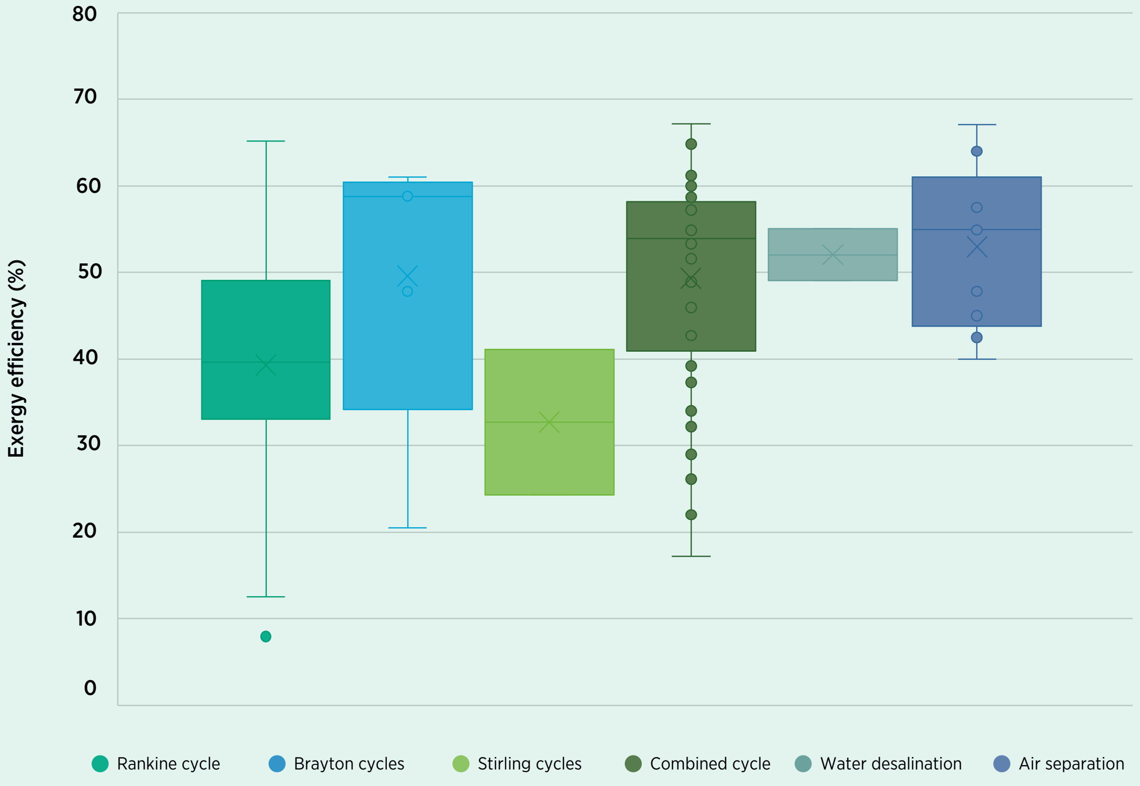


Source: Atienza-Márquez, Bruno and Coronas (2018).

Box 3.3. (Continued)

One of the applications is air separation. This requires compressing the air and cooling it through expansion (to reach up to -196°C). The major power consumption in the process is for compression. If cold from LNG (or hydrogen) is used, the expansion needs (and therefore compression) are lower. Some studies claim that the energy saving can be up to 50% (Jieyu et al., 2015). This possibility of liquefying air also opens up the possibility of using it for energy storage (Zhang et al., 2018). The cold can also be used to cool certain working fluids as part of a power generation cycle. Multiple fluids could be used for this purpose including propane, aromatic hydrocarbons, ammonia and nitrogen, among others (Mehrpooya, Sharifzadeh and Katooli, 2018). Cold could also be used for water desalination by freezing the water and separating the salt (Chang et al., 2016). The efficiency for some of these pathways is shown in Figure 3.18. The potential for cold production from LNG was identified as 12 GW in 2015 (IGU, 2016). Since then, the capacity has expanded by about 12% up to the end of 2020.

FIGURE 3.18. Exergy efficiency for use of cold from LNG regasification



Notes: Line inside the box represents median; × in the box represents average; the bottom line of the box represents the first quartile; the top line of the box represents the third quartile; the whiskers (vertical lines) represent the minimum and maximum value; dots outside the box represent outliers.
Source: Mehrpooya et al. (2018).

Most of these applications are not applied at scale and would require further demonstration to be applied. More specifically for LNG, none of them is applied as most of the LNG is heated with seawater. Some of the additional barriers that hinder the use of the cold are the distance to the potential users and finding a cost-effective way to transport the heat transfer fluid, fluctuating cold demand and the need for co-ordination by two different types of stakeholders (Atienza-Márquez, Bruno and Coronas, 2018).

4

LIQUID ORGANIC HYDROGEN CARRIERS

LIQUID ORGANIC HYDROGEN CARRIERS

Highlights

Liquid organic hydrogen carriers (LOHC) are compounds that can react with hydrogen and be used multiple times. The hydrogen is "loaded" into the carrier at the exporting site and "unloaded" at the importing terminal. These compounds are mostly oil derivatives and could build upon existing facilities with no boil-off losses and a liquid state at ambient conditions. Conversion (hydrogenation) and reconversion (dehydrogenation) are only being done in pilot projects and need to scale up further to reach the size needed for global trade. Shipping could be done as for oil transport today with limited adaptations.

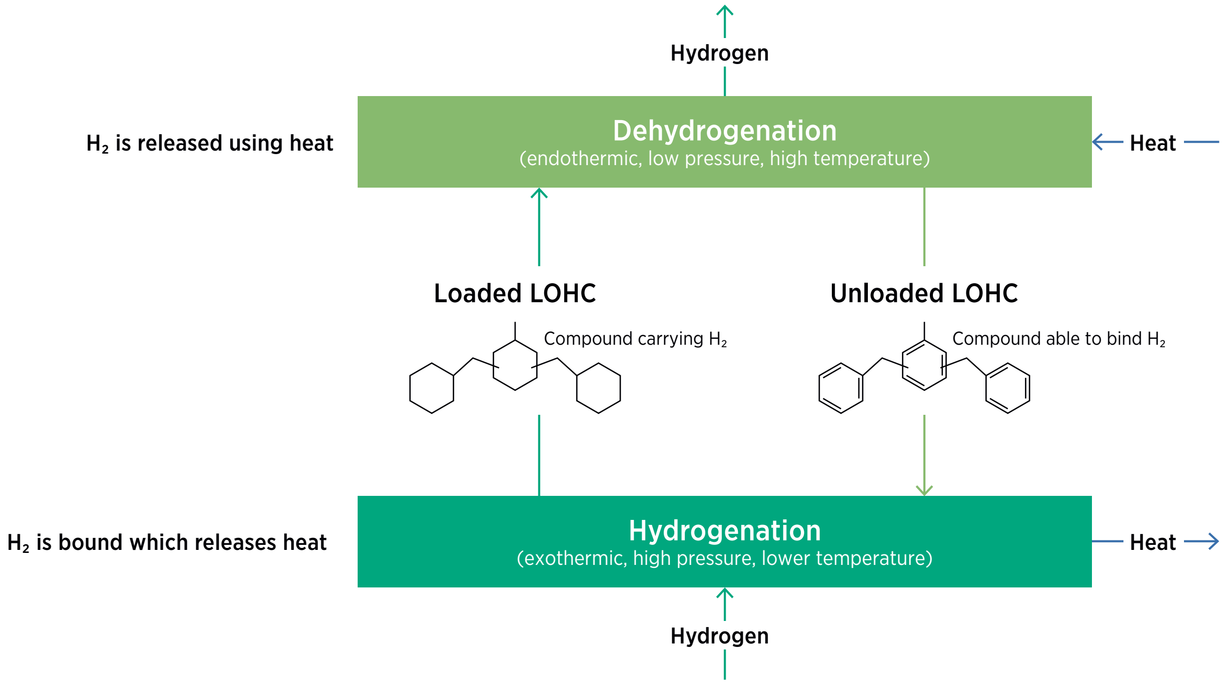
There are several challenges associated with LOHC. Sustainable pathways for the carriers have not been proven and currently rely on oil production. While the carrier is recycled, there are losses (about 0.1% per cycle) that would require compensating. Should some of these losses find their way into the environment, it would mean fossil carbon being released. Further research is needed to demonstrate and scale up a sustainable route. Most LOHC are speciality chemicals that are produced in limited quantities and would require production to be scaled up multiple times just to satisfy this new market. Given the small market size for most LOHC, they are subject to low liquidity, which can lead to price spikes due to small changes in supply and demand. This makes the capital cost of the inventory significant, increasing the overall working capital that would be needed to establish this pathway for global trade. All LOHC have a relatively low hydrogen content (4-7% weight), which translates into a large mass of LOHC to be transported and increases the share of the cargo that is consumed as fuel. An alternative is to use another fuel (e.g. ammonia or diesel) instead of the cargo, but this supports the case for pursuing other pathways (ammonia), or could compromise the environmental performance of the pathway (fossil diesel).

One of the main limitations of this pathway is the heat required at a medium temperature level (270-320°C) to recover the hydrogen from the carrier. This energy consumption is equivalent to 30-40% of the energy contained in the hydrogen and is limited by thermodynamics (which means even with research it will not decrease drastically). In short, this pathway presents multiple challenges that can limit its role in global hydrogen trade.

4.1 Technology status

In this pathway the hydrogen is bound to a liquid hydrocarbon and is released back at the importing terminal. The carrier is regenerated upon dehydrogenation so it can be shipped back to the exporting terminal for another cycle (see Figure 4.1). The absorption releases heat, while the dehydrogenation requires exactly the same amount of heat (since it is the opposite reaction). How this heat is supplied has a fundamental impact on the economics and environmental impact (see Section 6.1). This pathway is not carried out on a large scale currently, and the conversion and reconversion steps still need to go through demonstration before reaching commercial scale, which technology providers expect will occur in the coming decade. The current LOHC capacity from Hydrogenious, one of the leading companies, is about 0.25 t/d, which means there is a wider gap in capacity (compared to ammonia or liquid hydrogen) to satisfy large-scale demand in the future. The largest plant in the world is being constructed in Germany (Chempark Dormagen) with a capacity of 5 t/d and funding has been received for a 24 t/d plant. This is in contrast to 3 000 t/d (or about 500 t/d in hydrogen terms) of typical capacity for an ammonia plant today.

FIGURE 4.1. Main steps and conditions of the hydrogen transport with LOHC



Source: Hurskainen (2019).

One advantage of this pathway is that the carriers are oil derivatives, which are already traded today around the globe with plenty of loading facilities and storage capacity. This makes LOHC suitable for routes that would require multi-mode transport (e.g. ship, rail and then truck). Another advantage is that some of the carriers considered are non-toxic (unlike ammonia), are not flammable, are liquids under normal conditions, and have no boil-off losses (unlike liquid hydrogen). Storage is stable and the carrier can stay in the hydrogenated state for long periods of time without losses or significant costs.

On the other hand, this pathway faces several challenges that could limit its large-scale deployment:

- **Load**. The hydrogen content of the carriers is small (in the order of 4-7% weight). This means that most of the weight transported is actually not hydrogen and a relatively high share of the hydrogen transported is consumed as fuel. For instance, a typical carrier ship with a cargo capacity of 110 000 t would only carry about 5 500 tH_2 and would consume almost a quarter of the hydrogen transported in a 20 000 km journey (e.g. Chile to Japan).
- **Fuel for ships**. Using the cargo as a fuel implies an onboard dehydrogenation unit, which means an additional space requirement, a high specific cost of the unit due to low economies of scale, and higher energy penalty since hydrogen would most likely be used to provide the heat. This is different from ammonia or liquid hydrogen where the cargo can be used directly. In cases where heavy fuel oil is used to power the ship, this would have a negative impact on the GHG emissions in the value chain, and where ammonia is used, it would require a separate storage system. An alternative being researched is the integration of the dehydrogenation unit and a high-temperature fuel cell, which could save space and energy but has a low efficiency of 45% (Preuster et al., 2018).[35]
- **Heat supply**. The amount of heat that dehydrogenation needs is non-negligible. For instance, the trading of 10 MtH_2 would need about 0.4 EJ of medium-temperature heat. Given the amounts available, using waste industrial heat (i.e. zero cost) from nearby sources will not be possible once a global scale is reached, also considering that the temperature level required (150-400°C) is frequently used for other applications rather than just being released to the environment. Furthermore, this heat needs to be co-located with dehydrogenation, which might not be the same place where hydrogen is needed.
- **Multiple carriers**. There is no clear winner for the chemical carrier to be used, although there are various promising options. While this provides flexibility in the quest for success, it also dilutes effort as researchers and companies are working on different options and their knowledge might not be fully transferrable from one to another.
- **Production capacity**. Most of the carriers being considered are niche speciality chemicals. This means the global production capacity would need to be scaled up multiple times to satisfy LOHC demand. For instance, transporting 10 MtH_2 a year over a distance of 20 000 km would require over 300 ships with a total inventory of almost 35 Mt of toluene. Global toluene production stood at about 30 Mt in 2020, which means one year of the world's entire production would be needed to satisfy the LOHC needs of 10 MtH_2 of trade (in comparison to global hydrogen demand of over 600 MtH_2 by 2050). At the same time, most LOHC are produced as one element of a mix of products, meaning there will be co-products, possibly saturating demand in those other markets. This would lead to price depreciation and lower incentives for LOHC production (or would need to be compensated with a higher LOHC price and a higher cost penalty for the hydrogen transport process).
- **High cost**. Also associated with their characteristics as speciality products, most LOHC have a high production cost in the range of USD 660-44 000/tonne (Niermann et al., 2019). This increases the total capital cost of the project. On the optimistic side (USD 660/t), the cost of

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[35] Electric output of the fuel cell in comparison with the LHV of LOHC-bound hydrogen.

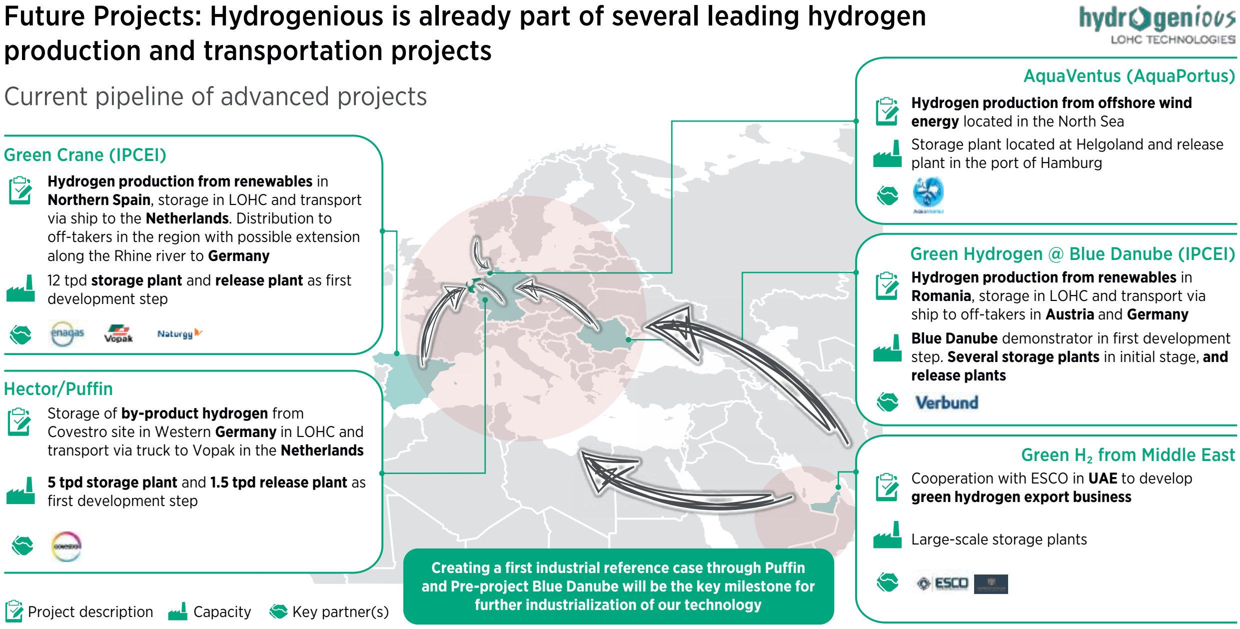
the carrier can be almost the same as the cost of the ships. This is in the order of USD 125 billion for the same 180 Mt of toluene mentioned above (for 10 MtH_2). This is a non-negligible part of the total project cost and it would be even more critical for more expensive carriers.

- **Losses**. While there are no boil-off losses, there are losses due to side reactions and during transfer. These are commonly quantified as losses per cycle of 0.1% (BNEF, 2019; Niermann et al., 2019; Teichmann, Arlt and Wasserscheid, 2012) but can reach levels of up to 3% per year depending on the number of cycles (Reuß et al., 2017; Stöckl et al., 2021). These losses mean that part of the carrier will ultimately be released into the environment with the associated environmental impact. It also increases the operational costs due to the need to compensate for losses and can already represent up to USD 0.05/kgH_2 for a relatively cheap carrier. Synthetic routes from electrolytic hydrogen and biogenic CO_2 or from the air are possible, but these would increase the carrier cost even further and would need to be demonstrated. Research into synthetic LOHC through biogenic CO_2 use is ongoing.

4.2 Project pipeline

The leading companies for LOHC are Hydrogenious LOHC Technologies and Chiyoda Corporation. Hydrogenious is a German company that uses benzyltoluene as a carrier and currently offers small-scale containerised LOHC units. Larger plants with a capacity in the range of 1.5 t/d for the dehydrogenation unit and 5 t/d for hydrogenation on a skid basis are planned (Hydrogenious, n.d.). Hydrogenious has been selected to receive funding for projects in Spain, the Netherlands and Germany from the Important Projects of Common European Interest (IPCEI). This is an instrument of the EU Industrial Policy Strategy and is meant to bridge the gap between R&D and commercialisation; it was launched for hydrogen in December 2020. Hydrogenious is also looking at the use of LOHC as a carrier for hydrogen as a fuel for shipping, with a target for a commercially ready product by 2025. Hydrogenious projects are mostly located in Europe (see Figure 4.2).

FIGURE 4.2. Current project pipeline for Hydrogenious



Future Projects: Hydrogenious is already part of several leading hydrogen production and transportation projects

Current pipeline of advanced projects

Green Crane (IPCEI)

Hydrogen production from renewables in **Northern Spain**, storage in LOHC and transport via ship to the **Netherlands**. Distribution to off-takers in the region with possible extension along the Rhine river to **Germany**

12 tpd **storage plant** and **release plant** as first development step

Hector/Puffin

Storage of **by-product hydrogen** from Covestro site in Western **Germany** in LOHC and transport via truck to Vopak in the **Netherlands**

5 tpd storage plant and **1.5 tpd release plant** as first development step

AquaVentus (AquaPortus)

Hydrogen production from offshore wind energy located in the North Sea

Storage plant located at Helgoland and release plant in the port of Hamburg

Green Hydrogen @ Blue Danube (IPCEI)

Hydrogen production from renewables in **Romania**, storage in LOHC and transport via ship to off-takers in **Austria** and **Germany**

Blue Danube demonstrator in first development step. **Several storage plants** in initial stage, **and release plants**

Green H_2 from Middle East

Cooperation with ESCO in **UAE** to develop **green hydrogen export business**

Large-scale storage plants

Creating a first industrial reference case through Puffin and Pre-project Blue Danube will be the key milestone for further industrialization of our technology

Disclaimer: This map is provided for illustration purposes only. Boundaries and names shown on this map do not imply the expression of any opinion on the part of IRENA concerning the status of any region, country, territory, city, or area or of its authorities, or concerning the delimitation of frontiers or boundaries.
Source: Schmidt (2021).

Some of their projects are for domestic hydrogen transport or storage, but three are related to international trade. The Green Crane project aims to promote hydrogen flows from southern to northern Europe. The project is led by Enagas (Spain) and SNAM (Italy). It involves the production of green hydrogen in Spain and transporting it via LOHC to the Netherlands, where it is expected to be used for road transport, stationary fuel cells, injection into the gas grid and as an industrial feedstock (H2V, n.d.). The first phase has a capacity target of 24 t/d and has already been selected to receive IPCEI funding (BMWi, 2021). The Blue Danube project envisages the establishment of a pan-European supply chain for green hydrogen based in the Danube region. The full project envisages the use of 2 GW of renewables coupled with a 1.5 GW electrolyser to produce over 80 000 tH_2/yr to be transported from Austria to Germany. Its first phase uses a 20 MW electrolyser to produce about 2 000 tH_2/yr. The final Hydrogenious project is exploring the potential to export hydrogen from the United Arab Emirates to Europe, but is still in the early stages.

In terms of concrete projects, the largest project by Hydrogenious is a plant at a chemical site in Dormagen (Germany). The plant has a target capacity of 1 800 tH_2/yr and aims to test three aspects: the catalyst's behaviour in real operation; possible influences of the LOHC or hydrogen quality on the hydrogenation process; and further development of industrially usable quality assurance procedures for the LOHC system. The project could also be expanded to import hydrogen from Rotterdam at a later stage. Green hydrogen is due to be provided in the future by Covestro Deutschland. Construction is expected to start in 2023. The state of North Rhine-Westphalia is supporting the project with funding of EUR 7 million (Hydrogenious, 2021).

Chiyoda is a global engineering company with experience in LNG and petrochemical plants. It developed the SPERA Hydrogen® technology, which is based on methylcyclohexane. It started R&D on LOHC in 2002, with catalyst development in 2008, a demonstration plant in 2014 (operation of a 50 Nm^3/hr unit for 10 000 hours) and the demonstration of global shipping in 2020. In the AHEAD (Advanced Hydrogen Energy chain Association for technology Development), Chiyoda partnered with Mitsubishi Corporation, Mitsui and Nippon Yusen Kabushiki Kaisha to transport hydrogen for use in power generation from Brunei to Japan (5 000 km) using SPERA technology. This project used steam reforming of natural gas as its production pathway. It could reach a maximum of 210 tH_2/yr and it was funded by NEDO (New Energy and Industrial Technology Development Organization).

Other relevant projects for Chiyoda are:

- A feasibility study for importing hydrogen into Singapore that started in March 2020 and has a target of 20-30 ktH_2/yr by 2026 and 300-400 ktH_2/yr by 2030. Five Singaporean companies are part of the project, including a producer and retailer of town gas, a port operator, a supply infrastructure operator and an LNG corporation.
- A feasibility study to assess the economic viability of large-scale import and distribution of hydrogen in the Chubu (Japan) region. Partners in the project include Sumitomo Corporation, Toyota, Japan Research Institute and Sumitomo Mitsui Banking Corporation. The project is also receiving support from NEDO. The uses considered include injection into existing gas pipelines and other uses across all sectors. If the project progresses, construction is expected by 2023, with a 40 000 tH_2/yr scale by 2025 and 110 000 tH_2/yr by 2030.
- A feasibility study for importing hydrogen into the Netherlands using LOHC, announced in July 2021. Chiyoda will provide the SPERA technology and Mitsubishi the value chain integration, importing to a Koole Terminal. The feasibility study is expected to take one year. It is the ambition of the companies to import 100-200 ktH_2/yr by 2025 and 300-400 ktH_2/yr by 2030.

- A feasibility study that was completed in 2019 for a 300 MW electrolyser project in British Columbia (Canada). It combined hydropower with a PEMFC electrolyser (from ITM Power) and LOHC (SPERA). The hydrogen demand was both for domestic use and export (California and Japan). The study received support from the British Columbia government.
- A joint Eneos and Chiyoda project for the development of a technology that combines the electrolysis and hydrogenation steps, reducing the cost from about USD 11/kg to USD 3/kg. Process intensification reduces the CAPEX by half. The target start year for the plant is 2030 and the targeted capacity is 500 kW, scaling up to 0.3 Mt/yr by 2030.

Other companies that are developing LOHC solutions include the following:

- H2-Industries uses dibenzyltoluene (DBT) as carrier and offers all the components of an LOHC-based Power-to-Power solution. The company's conversion module (H_2STORE) is less than 1 t/d (1.2 MW) and the reconversion module (H_2RELEASE) is even smaller at 0.7 t/d (1 MW). It has an integrated electrolysis and conversion technology that takes electricity and produces the loaded LOHC (eSTORE), but these come in small sizes of 1 MW of electric input with 60% efficiency. Similarly, it offers integrated reconversion and fuel cell technologies to convert loaded LOHC to power (eRELEASE), with an even smaller capacity of 0.3 MW of energy input and 50% efficiency. Storage sizes are 5-4 000 m^3.
- Framatome/Covalion (owned by EDF), which builds LOHC plants with DBT and is a licensee of Hydrogenious, has carried out some research into DBT.
- Hynertech is a Chinese company that supplies 1-50 kW high-purity hydrogen supply systems for mobile and stationary applications (Hurskainen, 2019).

In September 2021, Petronas and Eneos announced a feasibility study to export hydrogen from Malaysia to Japan. About USD 2.3 billion of the USD 18.2 billion green innovation fund from the Japanese government will be allocated to establish the first commercial-based international hydrogen trade, supporting the LOHC and liquid hydrogen routes to improve their costs.

Hydrogenious and H2-Industries are members of the AquaVentus project in Germany, which aims to deploy 10 GW of offshore wind in the North Sea by 2035 and use some of that to produce hydrogen and transport it to shore by pipeline. AquaVentus has connections with the TransHyDE project, which was started as a follow-up to the German hydrogen strategy and includes a project (Helgoland) to test the LOHC route. Green hydrogen is produced on an island, transported via a pipeline to shore and converted to LOHC for further transport inland. The dehydrogenation plant is being constructed in the Port of Hamburg.

4.3 Conversion (hydrogenation)

Hydrogenation is the process of binding the hydrogen to the LOHC. It is an exothermic reaction, which means it is thermodynamically favoured by low temperatures. However, to achieve a minimum reaction rate the process uses medium temperatures (100-150°C). It is also favoured by high pressures (10-70 bar) (Schneider, 2015). The pressure is generally lower than the operating pressure of the electrolyser, so intermediate compression can be avoided.

Alternative carriers

There are multiple LOHC that could be used. Some of the desired properties are (Hurskainen, 2019):

- A high hydrogen storage density (to reduce the amount of carrier needed).

- Low reaction enthalpy (to reduce the energy consumption for dehydrogenation).
- Low degradation (to avoid by-products and reduce top-up costs).
- Non-toxic (easier to handle).
- Cheap (to reduce both operating cost and initial inventory cost).
- High enough melting point to stay in liquid form even in cold conditions (easier to handle without losses).
- High boiling point (to avoid phase changes during processing).
- Conversion reactions take place in moderate conditions with low-cost catalysts (to reduce capital cost).

The potential LOHC are aromatics with double bonds between the carbon atoms. This means that upon hydrogenation, those C-C bonds are substituted by C-H bonds (called saturation), increasing the hydrogen content of the molecule. Molecules with other atoms like nitrogen and oxygen make the dehydrogenation easier, so some LOHC (e.g. NEC) use this approach (Jung et al., 2021). Table 4.1 shows some of the key properties for various compounds considered as potential LOHC. Sodium borohydride ($NaBH_4$) has also been proposed as an LOHC, but has been excluded from this list given the large energy requirement (181 GJ/tH_2), the need to recycle the solid powder, the consumption of the acid or catalyst precursor, and the low TRL (Tijdgat, 2020).

TABLE 4.1. Typical conditions for hydrogenation and chemical properties of LOHC

		NEC	DBT	BT	AB	FORMIC ACID	METHANOL	NAP	BENZENE	TOLUENE
Hydrogenation	Pressure (bara)	50	50	30	10	50	50	69	10-50	20
	Temperature (°C)	150	150	220	80	50	250	200	200	200
	STY (g/(L*hr))	388	279	296	78	8	220	218	-	467
Heat of reaction (kWh/kgH_2)		7.4	9.1	8.8	5.0	4.3	2.3	9.2	9.5	9.5
Price (USD/kg)		44	4.4	4.4	110	0.55	0.3	0.66	1	0.88
Market size (Mt)		<0.1	0.009	<0.01	<0.01	1.1	100	1	65	30
Amount needed for 10 MtH_2/yr[36]		15.7	14.7	14.7	13.0	20.7	7.3	12.5	12.6	14.9
Storage density (kgH_2/kgLOHC)		5.8%	6.2%	6.2%	7%	4.4%	12.5%	7.3%	7.2%	6.1%
Health hazard		1	0	-	-	3	1	2	2	2
Flammability		0	1	-	-	2	3	2	3	3
Flash point (°C)		186	200	132	23	69	11	88	-11	4.4
Boiling point (°C)		190	380	270	114	100	65	218	80	111

Notes: NEC = N-ethylcarbazole; DBT = dibenzyltoluene; BT = benzyltoluene; AB = 1,2-dihydro-1,2-azaborine; NAP = naphthalene; THF = tetrahydrofuran; STY = space time yield (a measure of reactor productivity and size needed for a fixed production rate). Health hazard and flammability are mostly taken from the NFPA (National Fire Protection Association) classification, which has a scale from 0 to 4 (0 is not flammable and no health unusual hazard upon exposure). Price for DBT could decrease to about EUR 1.65/kg at a scale of 0.1 Mt/yr (Hurskainen, 2019).

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[36] This refers to the total inventory needed, not the annual flows, and it assumes a 10 000 km journey.

One key parameter driving both the economics and the environmental impact of hydrogen transport with LOHC is the energy consumption, of which the major driver is the heat of reaction. The same amount of heat is released upon hydrogenation as is needed for dehydrogenation. Based on this, the best LOHC would be methanol (see Table 4.1), which requires about 25% of the energy that toluene would need. The theoretical 2.3 kWh/kgH_2 required for methanol is about 7% of the energy contained in the hydrogen.

The current global production of each of the LOHC is also useful to put into perspective how much the industry would need to scale up to satisfy a potential new market as a hydrogen carrier. To satisfy a hydrogen demand of 10 MtH_2/yr, Table 4.1 shows that a total amount of 7-21 Mt of carrier would be needed (considering that the carrier can be reused multiple times). The carriers that could support the largest transport market are methanol and toluene. Most of the carriers have a production level much lower than 1 Mt/yr given that some are speciality chemicals (see Table 4.1).

Some of the production pathways are not sustainable and some seem to have challenges for scaling up:

- Formic acid is produced from syngas[37] and could be further scaled up without constraints on the raw material. Syngas is mostly produced from natural gas and coal, but the process could transition to using CO_2 and green hydrogen as feedstock with the challenge that the pathway still has a low TRL of 3-5 (Pérez-Fortes and Tzimas, 2016).
- Naphthalene is mostly produced from coal tar and is one of its aromatic compounds. Tar is the heaviest and a more polluting component of coal. Expanding its use as a carrier based on coal tar as feedstock would not be sustainable. One sustainable pathway could be to use lignin as the raw material for producing benzene (Meng et al., 2021) and then producing naphthalene (Mebel et al., 2017). Benzene (along with toluene and xylene) could also be produced from methanol, which could in turn be produced in a sustainable way (e.g. biogenic CO_2 and renewable hydrogen) (Niziolek et al., 2016). A shortcoming of these routes is that they are based on theory and lab experiments, far from the industrial scale needed.
- Toluene is mainly produced in oil refineries by the catalytic reforming of naphtha (87% of global production), separation from pyrolysis gasoline, a by-product from steam cracking (9%), a by-product of styrene production, and from coal tars (Van Hoecke et al., 2021). As oil production and refining activities decrease to be in line with a 1.5°C trajectory, the traditional feedstock for toluene will decrease and fail to satisfy the LOHC market. Sustainable routes exist as mentioned above (benzene, toluene and xylene are usually produced together), with the limitation of low TRL and need for innovation before scaling up.
- DBT is produced from toluene and benzyl chloride. Benzyl chloride, in turn, is produced from toluene and chlorine. The annual production capacity for benzyl chloride in 2016 was 320 kt (HyStoc, 2019) while annual chloride production is about 75 Mt/yr (Li et al., 2021). Thus, DBT production would be potentially limited by the benzyl chloride capacity, but that may, in turn, be scaled up given a much larger production capacity for toluene and chlorine. Today, however, global DBT production is estimated to be just 9 000 t/yr (HyStoc, 2019), far from the scale needed to support a global LOHC market.
- AB is an aromatic compound that combines carbon, nitrogen and boron, and with chemical properties between benzene (organic) and borazine (the inorganic isoelectronic relative of benzene). The synthesis is complex – it was first done in 2009 (Marwitz et al., 2009)

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[37] A mixture of carbon monoxide and hydrogen.

and is not done on a commercial scale today. Thus, this route would present not only the challenge of having to transition to a sustainable feedstock, but also of reaching large-scale production.

- NEC is a carbazole, which is an aromatic compound combining two benzene rings with a pyrrole ring (a ring with nitrogen as opposed to carbon). In other words, it is another highly specialised chemical that is only produced in limited quantities today and ultimately derived from benzene. The thermal stability of NEC is relatively low since it decomposes at 180°C, which would pose challenges for its dehydrogenation (Jung et al., 2021).

Based on most parameters in Table 4.1, methanol is one of the most attractive carriers. From the perspective of the carrier price, methanol is the most attractive. Naphthalene, formic acid and even toluene have reasonable prices within the range where their cost would not be disproportionate compared to the rest of the value chain. For NEC, DBT and AB, however, the costs are considerably higher. Another key parameter is market size. For LOHC that have a small market base, LOHC demand could drive the market price and lead to a situation where small imbalances between supply and demand lead to even higher prices than today, making the entire supply chain too expensive. Such a market would also be dependent on a few players, which does not help competition, liquidity or cost reduction. For example, DBT is mainly supplied by Total, Sasol (now Eastman Chemical), Soken tecnix and Yantai Junzheng Fine Chemical (HyStoc, 2019).

Another property is volatility, the tendency of the compound to be in the gaseous phase. This has a twofold effect: it influences the tendency to have boil-off losses; and it defines the temperature at which the concentration of the compound in the gaseous phase is high enough to reach a flammable mixture. These are represented by the boiling and flash points respectively in Table 4.1. In this dimension, methanol is the worst performing; a low flash point of almost 10°C means that flammable mixtures are easily reached, which is reflected in a score of 3 for flammability.[38] The boiling point is also the lowest among the carriers. Toluene and AB also have a low flash point below ambient temperatures, which indicates they are more prone to form flammable mixtures than the rest. This high volatility is also related to forming vapours that can cause damage through inhalation, leading to a score of 2 under the NFPA for health hazards.

A common limitation of carbon-containing carriers is the availability of a sustainable carbon source, which faces the challenge of in either amount or cost. Direct air capture (DAC) currently has a cost of several hundred dollars per tonne, but the company Global Thermostat has large-scale proposals (1 $MtCO_2$/yr) for a high-temperature variation of DAC with a cost target of USD 94-232/tCO_2 (Keith et al., 2018), while low-temperature variations (Climeworks and Carbon Engineering) are targeting a similar cost of USD 100/tCO_2 once large-scale activity is reached (Climeworks, 2021). The impact this would have on the methanol cost, for example, is about USD 140/tCH_3OH for every USD 100/tCO_2 increase in the CO_2 cost (a 1.4:1 ratio). A relatively low cost of hydrogen at USD 2/kgH_2 would already represent about USD 430/tCH_3OH, making renewable methanol at least double the cost of the current fossil-based benchmark (see Figure 4.3).

The other sustainable CO_2 source is biogenic. There is a wide range of potential biomass estimates. The latest 1.5°C report from the IPCC suggests 40-310 EJ/yr of biomass potential, with the median at 150 EJ/yr (IPCC, 2018). Such median potential would be enough to produce

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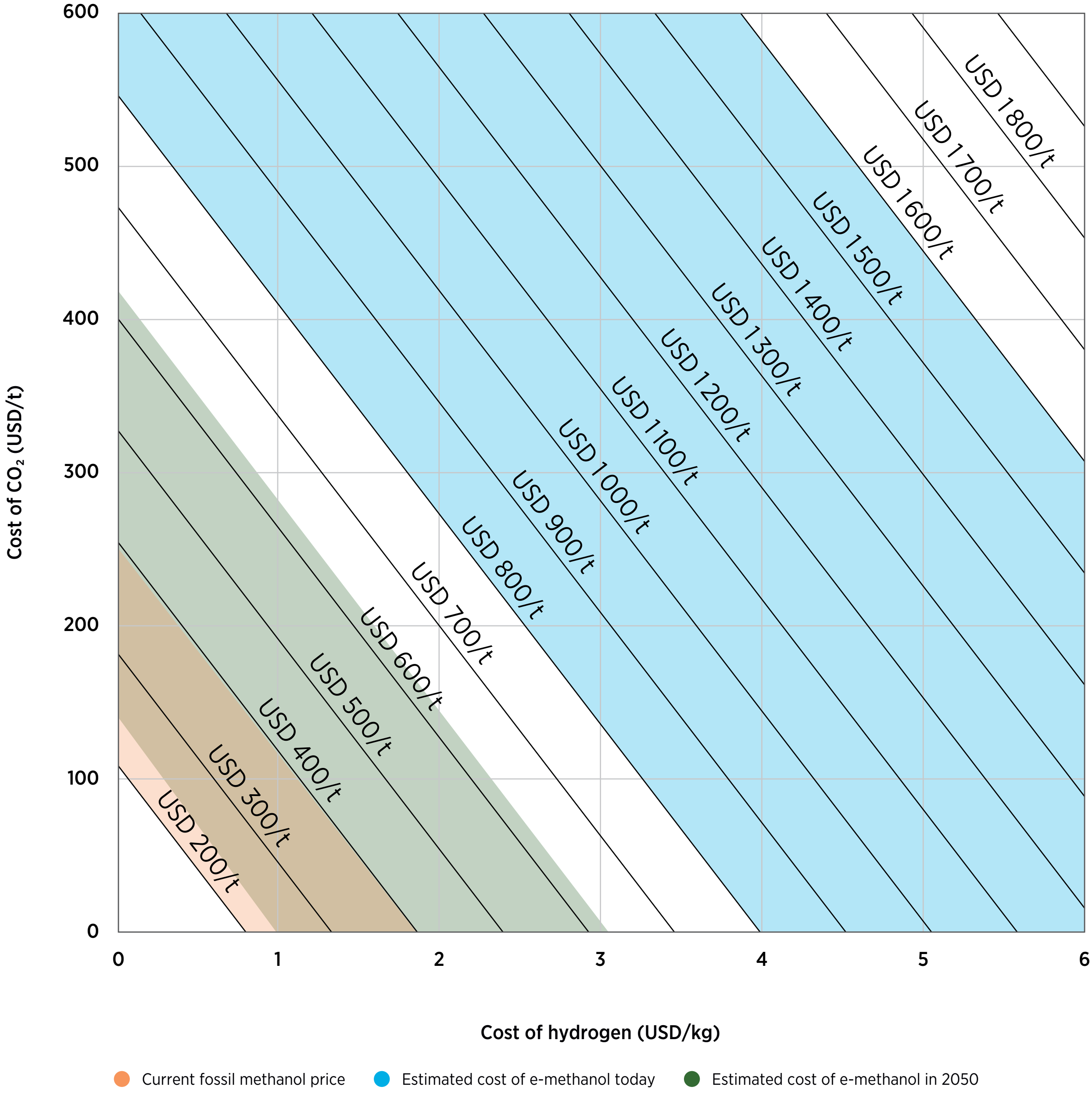
[38] Scale goes from 0 to 4, with 4 being the most hazardous.

about 15 $GtCO_2$/yr.[39] However, part of the carbon is needed for negative emissions (BECCS) and fuel production (synthetic fuels), leaving only a small fraction for lower-priority pathways such as LOHC.

The other limitation of using CO_2 as feedstock is energy consumption. DAC can consume about 10-12 GJ/tCO_2 (potentially falling to about 6 GJ/tCO_2 as the technology develops [Fasihi, Efimova and Breyer, 2019]). This would increase the overall energy consumption of the process to the equivalent of the energy contained in the today's hydrogen.

FIGURE 4.3. Renewable methanol production cost as a function of hydrogen and CO_2 cost



Source: IRENA (2021c).

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[39] With an LHV of 18 MJ/kg and a carbon content of 50% (by mass).

Energy consumption for hydrogenation

Like other pathways, two of the key parameters are efficiency and cost. As regards efficiency, the hydrogenation step is a net energy producer. The heat produced is at a medium temperature (150-250°C), which could be used for steam and power generation or for heat integration with other processes (e.g. if the facility is on an industrial park). From this perspective, the higher the heat production rate and the temperature the better since it means more heat is available for alternative uses. However, dehydrogenation is exactly the opposite reaction and any additional heat released during hydrogenation means more heat will be required in the importing region to dehydrogenate the carrier. Electricity consumption for the hydrogenation process ranges across 0.4-1.8 kWh/kgH$_2$ (see Table 4.2). The major consumption is for hydrogen compression where the electrolysis is carried out at low pressure. Toluene has a lower hydrogenation pressure (20 bar) compared to DBT (50 bar), which reduces the compression needs. This can lead to zero electricity consumption if toluene is used in combination with a pressurised operation of the electrolyser (Sekkesæter, 2019).

TABLE 4.2. Energy consumption for hydrogenation of LOHC

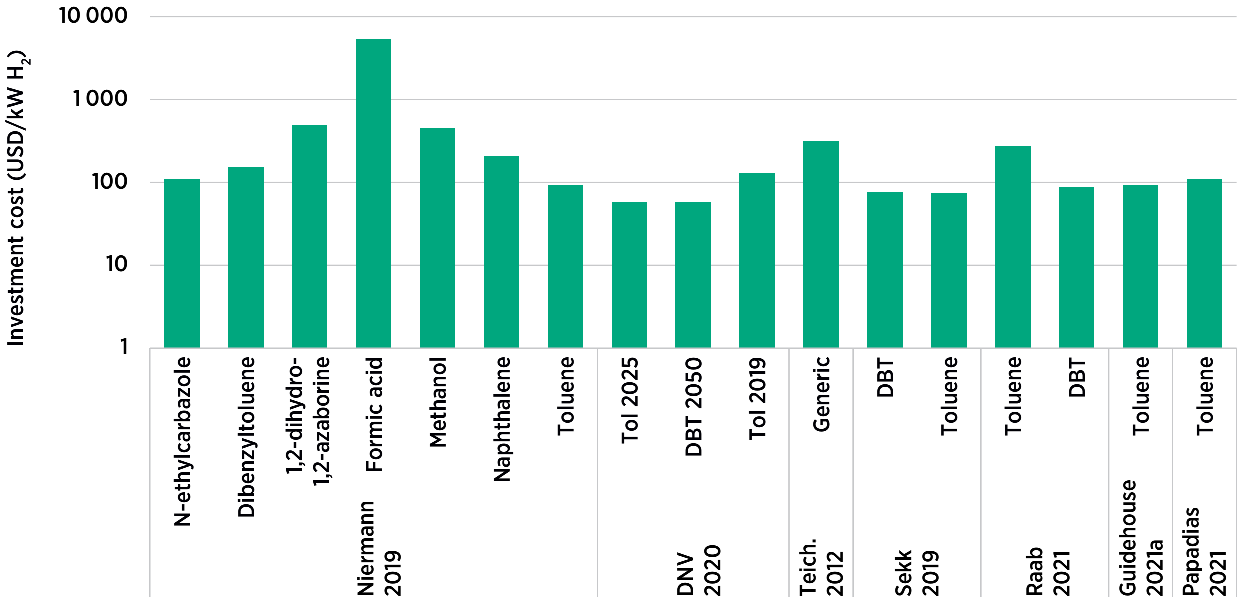
ELECTRICITY CONSUMPTION (kWh/kgH$_2$)	CARRIER	REFERENCE
0.37	DBT	Reuß et al., 2017
1.5	Toluene	IEA, 2019a
0.1	NEC	Niermann et al., 2021
0.1	DBT	Niermann et al., 2021
0.2	Toluene	Niermann et al., 2021
4.3	Methanol	Niermann et al., 2021
0.8	Toluene	BNEF, 2019
1.8	DBT	BNEF, 2019
1.4	Methanol	Pérez-Fortes and Tzimas, 2016
0.3663	DBT	Teichmann, Arlt and Wasserscheid, 2012
0.37	DBT	Stöckl et al., 2021
0.446	DBT	Sekkesæter, 2019
2.5	Methanol	Hank et al., 2020
1.7	Toluene	Guidehouse, 2021a

Notes: The table only reflects electricity consumption. Once the heat production from the reaction is considered, LOHC hydrogenation is a net energy producer.

Capital cost of hydrogenation

The hydrogenation process is relatively simple, with the hydrogenation reactor at the core, heat exchangers for heat recovery and hydrogen compression (if required). However, the reactor size is largely defined by the productivity of the reaction (see STY in Table 4.1). For reactions with low productivity, a large reactor would be needed resulting in a proportionally higher CAPEX. This means that the cost for formic acid synthesis is much higher than for toluene given the lower reactor productivity (see Figure 4.4). Most of the references are between USD 60/kWH$_2$ and USD 120/kWH$_2$, so these are the values used for the *Optimistic* and *Pessimistic* scenarios.

FIGURE 4.4. Specific investment cost for hydrogenation for different LOHC



Source: DNV (2020); Guidehouse (2021a); Niermann et al. (2019); Papadias, Peng and Ahluwalia (2021); Raab et al. (2021); Sekkesæter (2019); Teichmann, Arlt and Wasserscheid (2012).

A further factor is the behaviour of the cost with scale. Reuß et al. (2017) use a scaling exponent of 0.66, which was also adopted by Stöckl et al. (2021), while Niermann et al. (2021) use 0.6 for all the LOHC. At the same time, current plant sizes are only a few t per day, while a commercial plant is expected to be in the order of 800-1 000 t/d (see 6.1). Thus, the *Optimistic* and *Pessimistic* values are assumed to already correspond to the large-scale plants.

There are no major barriers up to 100 t/d. Larger scales need to consider the trade-off between cost, logistical (transport) and technological (design) aspects. Additionally, depending on the potential users' storage and release demands for hydrogen, it might be useful to have several trains of equipment, which would provide additional operational flexibility and reliability. This adds to the flexibility that low-cost LOHC storage can provide.

4.4 Shipping

The advantage of LOHC is that they can be handled in the same way as oil derivatives. They are stored and shipped close to atmospheric conditions (Tijdgat, 2020). Both toluene and methanol, which are two of the most attractive carriers, have low flash points, which mean they can easily form flammable mixtures requiring special handling. Toluene is transported in a chemical tanker (IMO Ship Type III) and falls in Category C of hazardous chemicals under MARPOL (The International Convention for the Prevention of Pollution from Ships). This means it presents a (minor) hazard to marine and human health in case of a spill and requires special operational conditions.

Energy consumption

Like the other hydrogen carriers, LOHC ships could use the cargo to fuel the ship. This requires an onboard dehydrogenation unit, which will occupy space and will have a relatively high specific cost due to the lack of economies of scale. One aspect that is different from other hydrogen carriers is that since the hydrogenated and dehydrogenated form of the carrier are different chemical compounds, additional tanks are needed for the fuel. At the beginning of the journey, these tanks are empty (meaning loss of cargo space) and will progressively be filled as the LOHC is dehydrogenated. Another difference is that most (93-95%) of the weight is the carrier, so on the ballast journey the fuel consumption is similar to the laden journey resulting in a higher fuel consumption overall. Once the hydrogen has been produced, it can be used in various prime movers with different efficiencies (see Table 4.3).

If an SOFC is used, the high-temperature heat could be integrated into the dehydrogenation process on board. The HyNjord project, which has received about EUR 2.5 million in funding from the Norwegian government, will test this configuration in a 200 kW pilot project. Hydrogenious LOHC Technologies GmbH and Johannes Østensjø dy AS are planning to have a MW-scale commercial product ready by 2025 (Østensjø, 2021).

TABLE 4.3. Prime mover efficiencies and heat recovery systems for LOHC ships

TECHNOLOGY	HEAT PRODUCED (kWh/kgH$_2$)	HEAT LEVEL (°C)	WASTE HEAT RECOVERY	EFFICIENCY (%)
SOFC	13	900	Heat transfer for dehydrogenation or combined cycle	68
PEMFC	9	90	None	42
ICE	8	400	Heat transfer for dehydrogenation	46
Gas turbine	20	600	Heat transfer for dehydrogenation	36
Steam turbine	20	500	Heat transfer for dehydrogenation	32

Note: Efficiency in the last column already captures the efficiency loss and heat integrated for dehydrogenation. For this reason, PEMFC is the lowest as it does not allow for heat recovery.
Source: Sekkesæter (2019).

In contrast to ammonia, which can be partially cracked during shipping, LOHC needs to be fully dehydrogenated, resulting in the full energy penalty for the production of fuel. Furthermore, dehydrogenation is carried out at atmospheric pressure, while some of the prime movers require the hydrogen to be at high pressure, meaning an additional onboard compressor is needed. Some LOHC do not provide full reconversion to pure hydrogen, leading to impurities. Notably, a PEMFC requires a highly pure hydrogen, which would need an additional onboard purification system, making it less attractive compared to the other options. Regarding the effect of speed on fuel consumption, very low speeds might incur an increase in specific fuel consumption given that ICEs are more efficient at higher loads.

Capital cost for ships

Two types of tanker could be used for LOHC: oil and chemical. Chemical tankers have a capacity of 5 000-59 000 dwt with a double hull and a stainless steel or epoxy coating. This would be the most suitable for toluene. IMO 3 cargoes (such as toluene) can also be carried in “clean tankers”, which have a capacity of 43 000-50 000 dwt. The hydrogenated form of DBT is non-toxic and non-corrosive, so it can be transported in product or crude oil tankers (Tijdgat, 2020). These have higher capacity: the AFRAMAX have 80 000-120 000 dwt, very large crude carriers (VLCCs) have 160 000-320 000 dwt and the largest ultra-large crude carriers (ULCCs) reach 550 000 dwt. While the larger tankers can reduce the specific cost of cargo transport, the number of ports that can handle their dimensions decreases (see Table 4.4). For this study, an average size of 110 000 dwt is used.

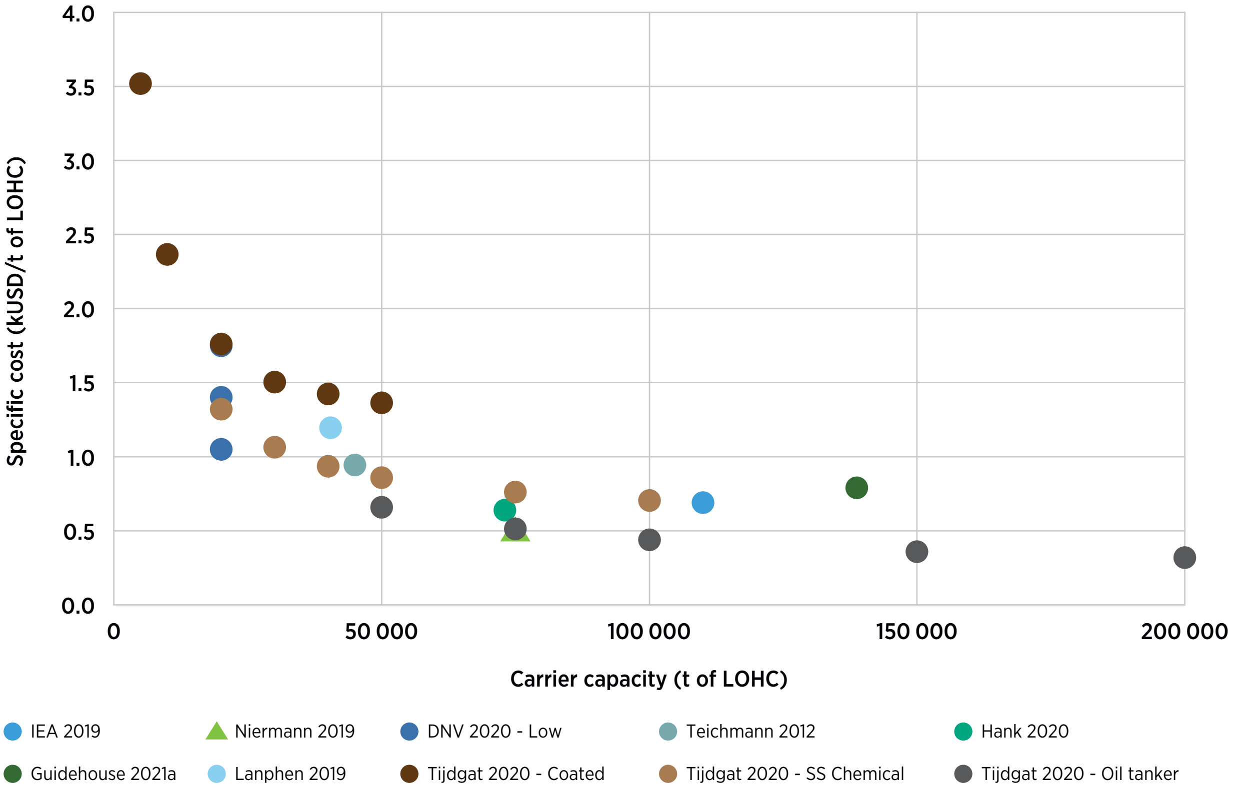
TABLE 4.4. Dimensions for different types of tankers

CLASS	LENGTH (m)	BEAM (m)	DRAFT (m)	WEIGHT (THOUSAND dwt)
Coastal tanker	205	29	16	<50
Aframax	245	34	20	80-120
Suezmax	285	45	23	125-180
VLCC	330	55	28	160-320
ULCC	415	63	35	320-550

Note: dwt = deadweight tonnage.
Source: Marine Insight (2021).

Economies of scale also apply to LOHC ships. For relatively small carriers of 20 000 dwt, DNV (2020) refers to uncertainty in the capital cost of the ship of USD 21 million to USD 35 million, resulting in a relatively high specific cost. As the size increases, costs tend to rapidly fall below USD 800/tLOHC for capacity above 60 000 dwt (see Figure 4.5). This converts to about USD 16 000 when expressed per tonne of hydrogen, which is between ammonia ships and liquid hydrogen ships (see Sections 2.4 and 3.4). The outcome is therefore a higher cost than ammonia ships combined with a lower efficiency due to higher weight and higher energy penalty for producing the onboard hydrogen. The fixed operating costs are assumed to be about 3% of the CAPEX (Teichmann, Arlt and Wasserscheid, 2012).

FIGURE 4.5. Investment cost for an LOHC vessel as a function of ship size



Notes: SS = stainless steel. Scale is in t of LOHC to be able to directly benchmark values with oil and chemical tankers (which are not hydrogen carriers); to convert values to USD per tonne of hydrogen, the hydrogen content can be used (see Table 4.1).
Sources: DNV (2020); Guidehouse (2021a); Hank et al. (2020); IEA (2019a); Lanphen (2019); Niermann et al. (2019); Teichmann, Arlt and Wasserscheid (2012); Tijdgat (2020).

4.5 Reconversion (dehydrogenation)

Dehydrogenation is carried out at atmospheric pressure and medium temperatures (see Table 4.5). This means the hydrogen needs downstream compression, which can incur a significant energy penalty (about 2 kWh/kgH$_2$ or 6% of the energy contained in the hydrogen).[40] The operation at atmospheric pressure also makes the compressor more expensive. Hydrogen is a small molecule that requires the use of displacement-type compressors such as piston and screw compressors, which have small maximum sizes and require multiple pieces of equipment in parallel, leading to poor economies of scale (Berstad et al., 2022).

Dehydrogenation is a catalytic reaction based on palladium or platinum (content of precious metals is typically below 0.5% weight). The catalyst productivity is about 500 t of LOHC per hour per every kilogram of catalyst, and the catalyst cost is around USD 165/kg (Teichmann, Arlt and Wasserscheid, 2012). Furthermore, the conversion rate of the reaction is not 100% for all carriers. This requires a separation process downstream of the reactor, increasing the capital cost. A pressure swing adsorption (PSA) process is commonly used to improve the hydrogen quality. The PSA equipment is also needed for the by-products formed from side reactions that take place due to the high temperatures (Jung et al., 2021). This process, however, does not result in full hydrogen recovery (90%), some of the hydrogen ending up in the off-gas. The off-gas, in turn, can be combusted to generate the heat required for the dehydrogenation. Additionally, there are heat losses in the process and deviations from ideality that push the heat requirement about 20-30% higher than the enthalpy of the reaction in Table 4.1. For example, the heat of the reaction for toluene is about 9 kWh/kgH$_2$, while the process energy consumption is about 13.2 kWh/kgH$_2$ (Niermann et al., 2021). Actual energy consumption from equipment supplied by manufacturers is 12 kWh/kgH$_2$ (Schmidt, 2021). Dehydrogenation also requires a burner for the off-gas and fuel to provide the heat needed for the reaction.

TABLE 4.5. Typical conditions for dehydrogenation and chemical properties of LOHC

	NEC	DBT	BT	AB	FORMIC ACID	METHANOL	NAP	TOLUENE
Dehydrogenation								
Pressure (bara)	1	1-2	1	1	1	1	1	1
Temperature (°C)	270	310	260	80	60	420	280	320
STY (g/(L*hr))	163	28	32	27	0.2	45	16	62
Conversion (%)	90	97	99	99	100	100	99	95

Notes: NEC = N-ethylcarbazole; DBT = dibenzyltoluene; AB = 1,2-dihydro-1,2-azaborine; NAP = naphthalene; THF = tetrahydrofuran; STY = space time yield (a measure of reactor productivity and size needed for a fixed production rate). Health hazard and flammability are mostly taken from the NFPA (National Fire Protection Association) classification.
Sources: Aakko-Saksa et al. (2018); Jorschick et al. (2020); Niermann et al. (2019); Schneider (2015).

One option to decrease the energy consumption of the downstream hydrogen compression is to run the dehydrogenation at higher pressure. There is, however, a temperature and pressure trade-off, with higher pressures requiring higher temperatures to achieve the same conversion (see Figure 4.6). Thus, it depends on the temperature of the heat available; as higher temperatures will also cause slightly higher energy consumption, it is not usually attractive.

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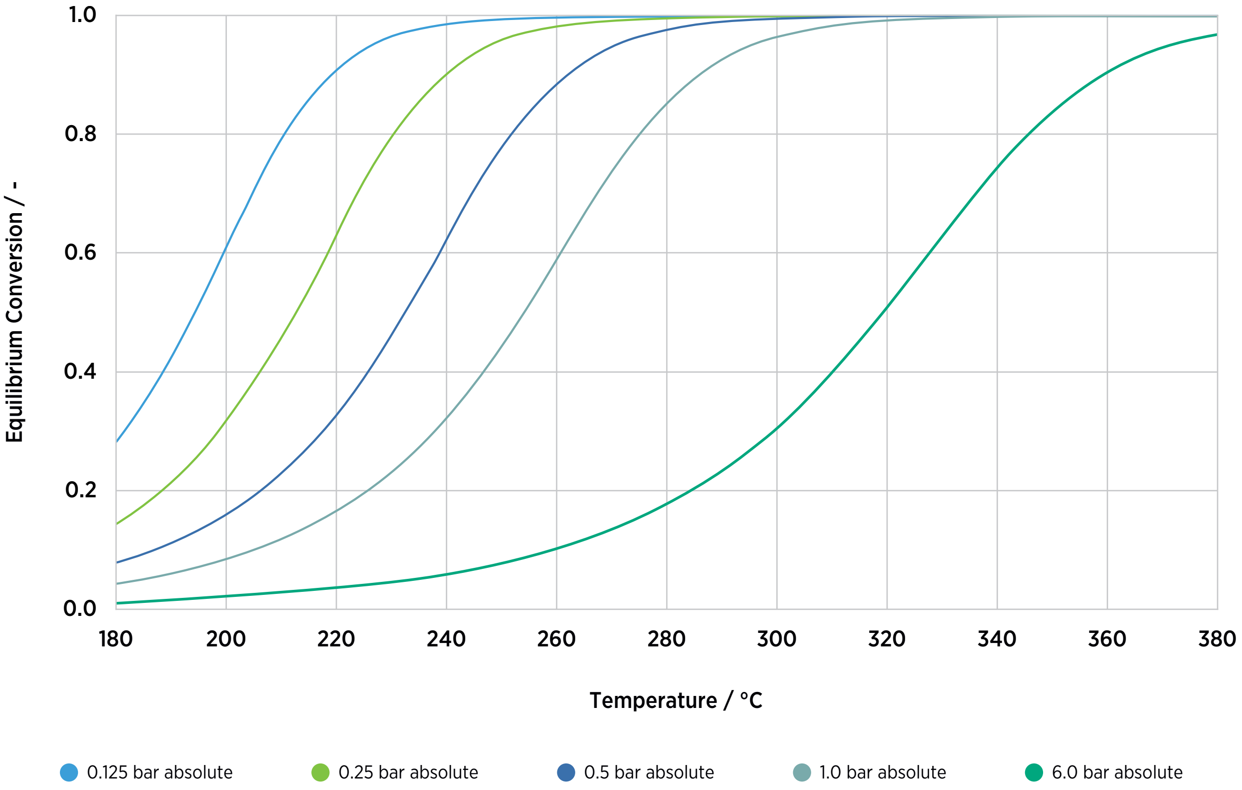
[40] The outlet of the reactor needs to be compressed to 40-70 bar for the separation, and the separation product (pure hydrogen) needs to be recompressed to reach the delivery pressure as the pressure is lost in the separation process.

Most dehydrogenation processes operate at atmospheric pressure (Niermann et al., 2019), with some configurations going up to 2 bar(a) (Papadias, Peng and Ahluwalia, 2021). Furthermore, there are conversion and separation losses. For instance, the conversion from MCH reaches over 95% with a toluene selectivity of 99.9% and a hydrogen yield of 95%, so the hydrogen losses are relatively modest and can be used to supply the heat needed for the reaction.[41] The catalyst lifetime is only one year, increasing the operating cost (although catalyst cost is only about 2-3% of the operating cost) (Chiyoda Corporation, 2018). For a relatively small plant of 225 ktH_2/yr, seven dehydrogenation reactors would be needed (Raab et al., 2021).

FIGURE 4.6. Equilibrium conversion for LOHC dehydrogenation as a function of pressure and temperature



Source: Mrusek et al. (2021).

The heat demand for dehydrogenation can be supplied in various forms (see Section 6.1). In instances where it is supplied by variable renewable energy, the flexibility of the system becomes relevant. There are mainly three parameters that can be varied to adjust the hydrogen production (Fikrt et al., 2017):

- The operating temperature of the reactor. As the supply is cut, the temperature will not instantaneously decrease, and the reaction can continue as the reactor cools down. If the renewable supply is restored, the reactor can be heated up again. One factor to consider is that the time it takes to cool down/heat up will depend on the reactor mass and heat capacity, and the heating system. Furthermore, if temperature changes are severe enough during these cycles, it can lead to early material failure due to thermal fatigue.
- The LOHC mass flow. The heat input required is proportional to the amount of LOHC and hydrogen produced. Decreasing the feed of the reactor would reduce the total hydrogen

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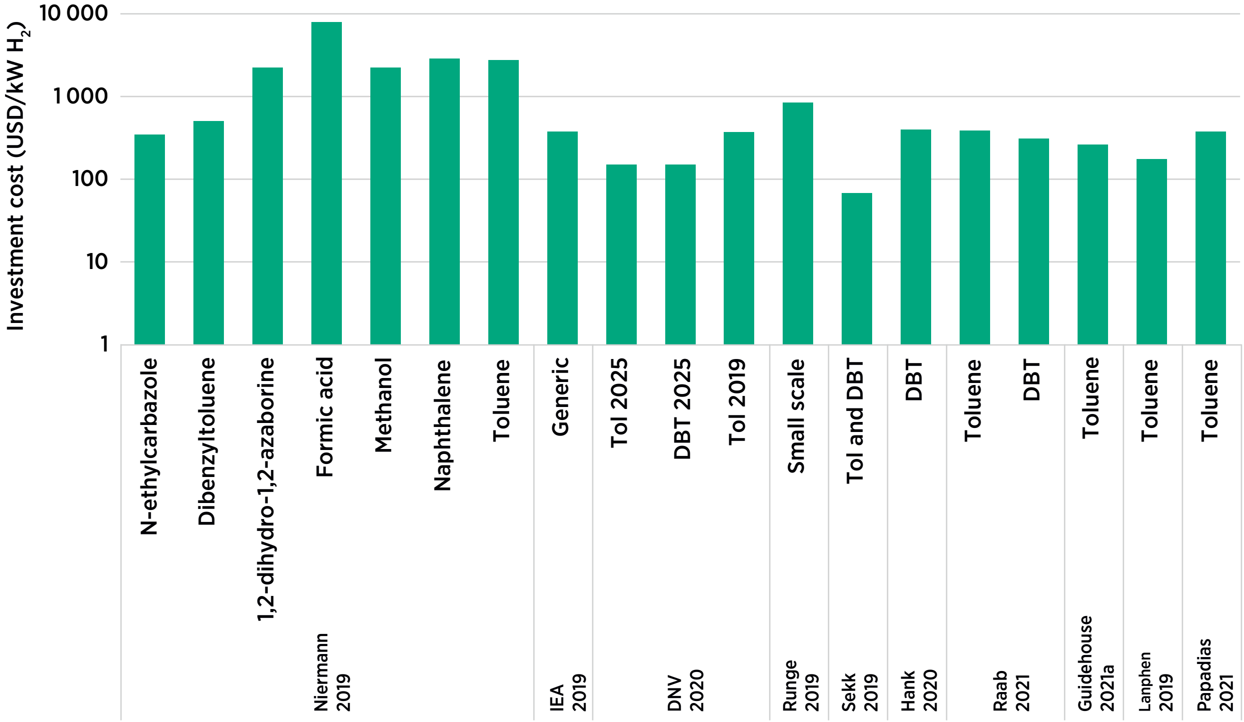
[41] Methylcyclohexane is the hydrogenated form of toluene.

produced and could keep the reactor in a hot state longer, giving a greater opportunity to restore the energy supply.

- Pressure in the reactor and equipment inventory. If the fluctuations are short (in the order of seconds or perhaps a few minutes), the pressure in the reactor could be changed as a lever to change the reaction rate and, therefore, the heat required. The specific effect will depend on equipment design, but pressure fluctuations could also lead to earlier material failures.

The range of costs for dehydrogenation in various studies is shown in Figure 4.7. Like hydrogenation, the reactor size is defined by its productivity (see Table 4.5). As a consequence, formic acid has a considerably higher cost than the alternatives. Most of the cost estimates are between USD 100/kWH$_2$ and USD 250/kWH$_2$, so these are used as the *Optimistic* and *Pessimistic* assumptions, with the potential to be even lower if larger facilities are considered.

FIGURE 4.7. Specific investment cost for LOHC dehydrogenation



Sources: DNV (2020); Guidehouse (2021a); Hank et al. (2020); IEA (2019a); Lanphen (2019); Niermann et al. (2019); Papadias (2021); Raab et al. (2021); Runge et al. (2019); Sekkesæter (2019).

In terms of flexibility, LOHC dehydrogenation seems to be mainly suited to fluctuations on a minute scale within about 30% of the set point (with larger peaks possible with a shorter duration). Due to the long start-up period (resulting from the thermal mass of the reactor), the technology is mainly suited to a constant flow or at least only short periods of shutdown. However, some decomposition might occur if the LOHC material is kept inside the reactor for long periods at high temperatures (Fikrt et al., 2017).

5

HYDROGEN PIPELINES

COMPRESSED HYDROGEN VIA PIPELINES

Highlights

Pipelines become more attractive as the volume to be transported increases, because as the pipe diameter increases, its capacity increases more rapidly than the amount of material needed. Costs well below USD 1/kgH_2 can be reached for the largest pipelines and 5000 km, with the capital cost of the pipeline representing the main cost contributor. An alternative to reduce the capital cost by 65-94% is to repurpose some of the 1.4 million km of existing natural gas transmission pipelines. The main challenges to achieving this benefit are material compatibility and higher energy consumption for compression, but these are not expected to outweigh the advantages. Material compatibility needs to be assessed on a case-by-case basis, but studies completed so far (mostly in Europe) show that a large part of the network can be repurposed. Furthermore, not all the network might be needed, since the need for hydrogen transport might be more limited when compared to natural gas today. Repurposing natural gas pipelines for hydrogen has already been proven (in the Netherlands) and future networks are already heavily reliant on this option. However, this option is not widely available across the world and is mostly limited to North America, eastern China, Europe and Russia.

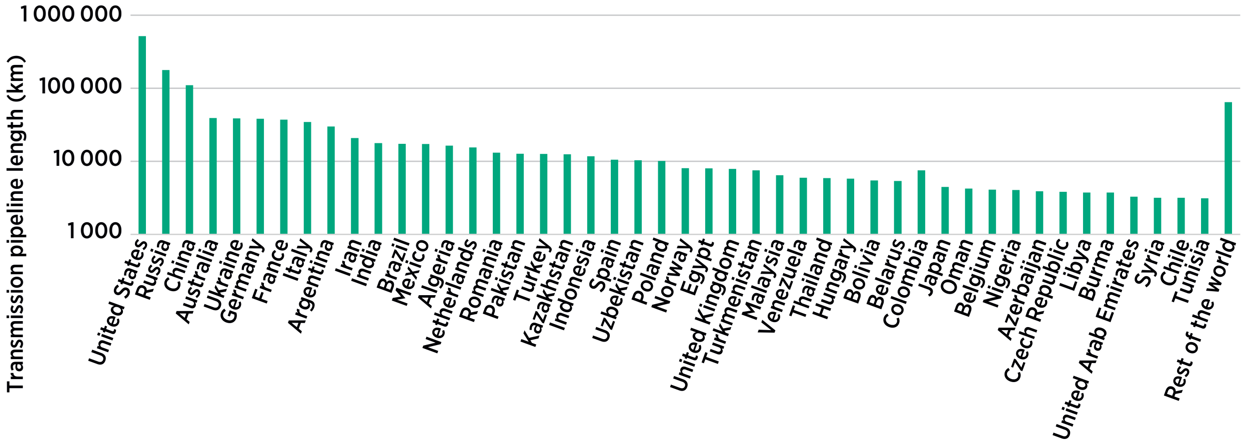
Blending can also be an option to use existing infrastructure. The only benefit is that it allows production to be scaled up without the need to include infrastructure or end use within the scope of the project, given that the hydrogen would be injected into the gas grid. However, this option faces multiple challenges. The CO_2 benefit is small, equivalent to about a third of the blending fraction (i.e. a blending target of 20% by volume only leads to about 7% lower CO_2 emissions). It increases the gas price, as relatively cheap hydrogen of USD 3/kgH_2 is still about 10 times higher than the typical natural gas price in the United States (assuming USD 2.5 million British thermal units (MMBtu)). This results in an equivalent GHG mitigation cost that can exceed USD 500/tCO_2. Blending implies mixing a high-value commodity with a cheap one and would require expensive separation (at least USD 1.5/kgH_2) if pure hydrogen is needed. Hydrogen limits are not consistent across borders and there is currently no regulation of the variability of the hydrogen concentration with sufficient temporal resolution to capture the changes introduced by wind and solar, for example, during the course of a week. Blending is only at the pilot project scale and further de-risking is needed, so it is not an option that is readily available.

Transporting hydrogen is already a mature technology and there are 4 600 km of pure hydrogen pipeline in the United States and Europe. Hydrogen storage is also proven on a large scale, but only in six salt caverns in the United States and the United Kingdom. Salt caverns represent only about 10% of the world's natural gas storage capacity and other types of reservoirs would be needed to ensure there is enough storage capacity for all countries, as salt formations are not equally spread around the globe. To be able to access the existing natural gas storage capacity, further research is needed to overcome the challenges associated with other types of reservoirs such as depleted oil and gas fields, aquifers and lined rock caverns.

5.1 Technology status

There are almost 1.4 million km of natural gas transmission pipeline around the world (CIA, n.d.), while the are only about 4 600 km of pure hydrogen pipeline (mostly in the United States and northwest Europe) (HyArc, 2016). The natural gas network in the United States accounts for almost a third of the world's total, with Russia in second place at less than 12.5% of the global length (see Figure 5.1). These are pipelines that could be potentially repurposed for hydrogen, leading to lower transport costs.

FIGURE 5.1. Total natural gas transmission network length by country.



Sources: CIA (n.d.); Rodríguez-Gómez, Zaccarelli and Bolado-Lavín (2016).

Repurposing natural gas pipelines

Some of the aspects to consider when evaluating repurposing gas pipelines are material suitability, compression needs and pipeline capacity. Regarding materials, a key challenge is hydrogen embrittlement. This is where atomic hydrogen diffuses through the structure of the steel, reducing the ductility of the material, its toughness, and tensile strength, making the pipeline more likely to fail. The susceptibility depends on the specific type of steel[42] and conditions such as pre-existing cracks, cyclic loading (e.g. due to fluctuations in pressure) and sulphur content can make this mechanism worse. Hence, the suitability of a pipeline for repurposing is very specific and needs to be done on a case-by-case basis. The higher vulnerability that cracks introduce can be mitigated with changes in the pipeline monitoring system, which can result in a higher operating costs. Other methods of repurposing pipelines are the use of an internal coating, inhibitors or a pipe within the pipeline (Cerniauskas et al., 2020). Options to deal with hydrogen embrittlement are more continuous monitoring to detect and monitor crack growth and reduced operation with pressure variations (i.e. cyclic loading) (Guidehouse, 2020).

Hydrogen emissions can occur in three ways: permeation through the steel, leakage and operational emissions. Permeation rates are very small compared to the other two. Hydrogen is more prone to leakage than methane, due to the smaller size of the hydrogen molecule. This means components such as pressure regulators, valves and seals need to be replaced to repurpose natural gas pipelines for hydrogen. Similarly, different gas meters are also needed since hydrogen has different gas properties and pipeline operation methods, including pressure fluctuation control. Depending on the hydrogen purity needed, a thorough purging and cleaning procedure is needed to ensure there are no impurities left in the pipeline. These requirements are a relatively small fraction of the total costs (HyWay, 2021). If planned well in advance, these components could also be replaced by hydrogen-ready devices as part of the regular maintenance schedule.

The volumetric energy content of hydrogen (MJ/m^3) is about a third of that of natural gas. This means that three times more volume would be needed to transport the same amount of energy. At the same time, its lower molecular weight and gas properties result in a mass density that is about nine times lower than natural gas. Both factors almost cancel each other out, and it means that for an existing pipeline (i.e. same diameter) and a fixed pressure drop, the energy transport capacity with hydrogen is 80-98% of the energy capacity of the natural gas pipeline (Haeseldonckx and Dhaeseleer, 2007).

The compression power demand for hydrogen is three to four times higher than for natural gas due to its lower volumetric energy density and the larger volumes handled. The power requirement has a non-linear behaviour with respect to the pressure differential, which can mean that it is better to compress it more frequently instead of using larger compressors further apart. This means the optimal distance between compressors will most likely be different from the existing natural gas compression stations. Alternatives (resulting in a non-optimal pressure profile) are to increase the compression power or deliver the hydrogen at lower pressures. Compressor locations can be influenced by pipeline utilisation, terrain, and injection and withdrawal points, among other factors. Given the larger volume, investment costs for the hydrogen compressor can be 40-80% higher than for natural gas and the energy required is about three times higher than for natural

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

gas. This higher energy consumption still represents less than 1.5-2% of the transported energy for every 1000 km in most cases (Guidehouse, 2020).[43]

An electrolyser can be designed to operate at 30 bar or higher, while the transmission pressure can be 40-80 bar, meaning that compression is required in most cases. The energy consumption for this step can be about 1% of the energy contained in the hydrogen when compressing from 15 bar to 70 bar. There is a balance to be found between a higher cost for an electrolyser designed for high pressure and a lower cost to undertake compression (IRENA, 2020).

Previous conversion examples could serve as a reference for hydrogen. These are the change from town gas to natural gas in Europe following initial production from the North Sea (1960s) (Dodds and Hawkes, 2014) and the conversion from low-calorific gas to high-calorific gas in northwest Europe with the closure of the Groningen field (IEA, 2020a). All these cases required progressive repurposing from one gas to another, involving simultaneous adaptation by downstream users (both industrial and residential) to the new gas properties. This transition took about ten years in both cases and would be similar for a change from natural gas to hydrogen.

Blending

Another option to use the existing infrastructure is to blend hydrogen with natural gas in the existing network. The benefits are that the gas network is ubiquitous in some regions (e.g. Europe, North America, Russia and eastern China) and it allows production to be ramped up without the need to consider transport and end use in the same project. This can facilitate financing and execution due to the narrower scope and also provide a guaranteed offtake that decreases project risks. Some equipment used for residential heating is already tolerant of up to 20% (by volume) blending. There are, however, multiple disadvantages that limit the prospects of this option:

- **Limited CO_2 benefit.** Each component of the gas network has a different tolerance to hydrogen. The limit for the network is defined by its least tolerant component. Existing gas turbines, compressors, metering equipment, CNG tanks and industrial users are among the most sensitive components (Marcogaz, 2019). The tolerance of CNG tanks, for example, can be as low as 0.1% (by volume) (UN, 2014). In instances where the downstream users can handle it, blending of up to 20% (by volume) without major investment can be achieved. After this threshold, more research and more investment are needed. A 20% fraction only represents about 7% in energy terms (due to difference in molecular weight), which means blending could achieve, at best, only 7% CO_2 emissions reduction.
- **Higher energy cost.** Hydrogen is a relatively expensive carrier, while methane is among the cheapest. A relatively low-cost gas at USD 2/GJ (typical in the United States) is still four times cheaper than a very low cost of hydrogen at USD 1/kg.[44] Thus, as hydrogen is blended in the grid, it will progressively increase the gas price, which has to be compensated by the government through subsidies (not sustainable) or paid by the end consumer (increasing energy prices and potentially leading to equity issues) (IRENA, 2021d).

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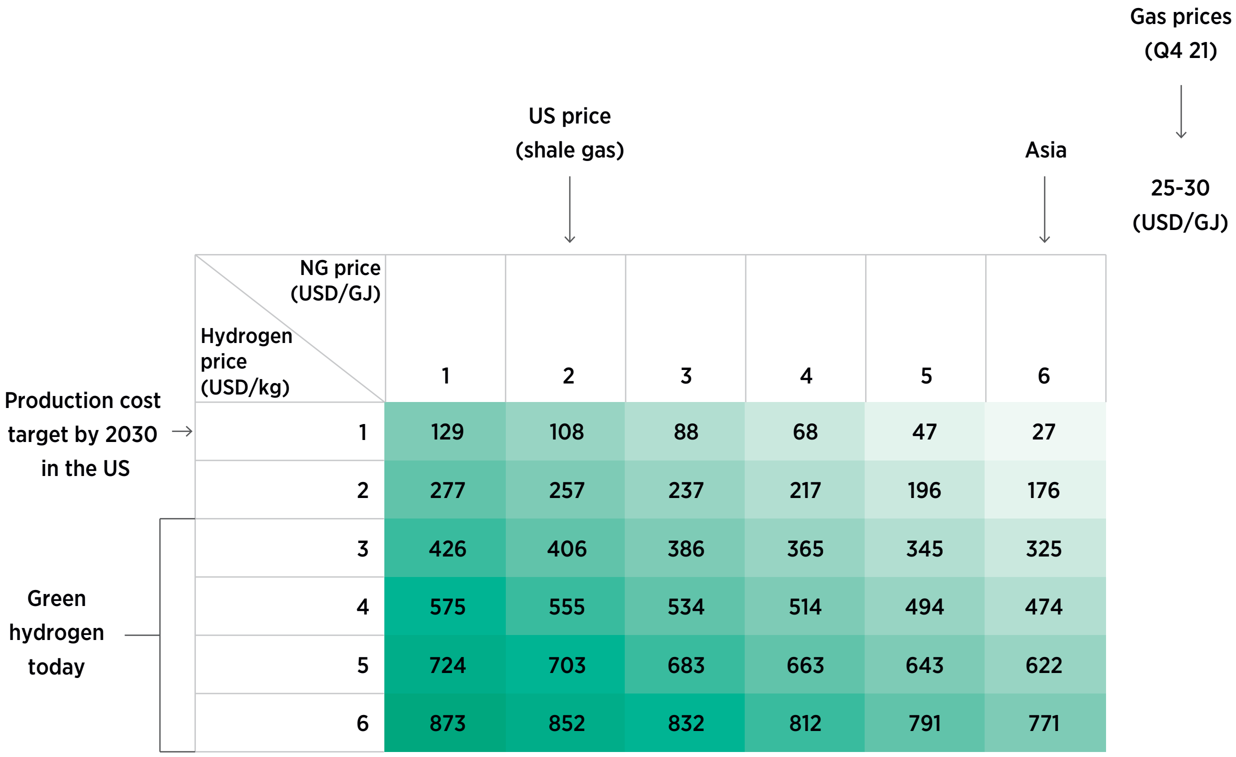
[43] Compressors would use the local electricity grid rather than the energy in the transported hydrogen, so this is just to put the energy consumption in perspective.

[44] For reference, hydrogen from natural gas with carbon capture can be as low as USD 1.4-2/kg (depending on gas price) and renewable hydrogen can be USD 3-6 USD/kg (depending on electricity price).

- **Tolerance of users.** The tolerance of the network is only as high as its most sensitive component. While many residential appliances are tested for up to 23% (Altfled and Pinchbeck, 2013) and there are projects that have demonstrated up to 30% blending without any problems (Kippers, 2011), most downstream users are tolerant to a few percentage points of hydrogen, with existing gas turbines, CNG vehicles and feedstock among the most sensitive components (Marcogaz, 2019). This means that if any of these applications is on the network, the blending limit will be low.
- **High mitigation cost.** Blending leads to limited CO_2 benefits and to a large increase in energy cost. This translates into a very high cost of mitigating the GHG emissions of natural gas (see Figure 5.2). Given the current production cost for renewable hydrogen, the cost may be above USD 500/tCO_2 for most gas prices (see Figure 5.2).

FIGURE 5.2. CO_2 mitigation cost for different combinations of natural gas and hydrogen prices

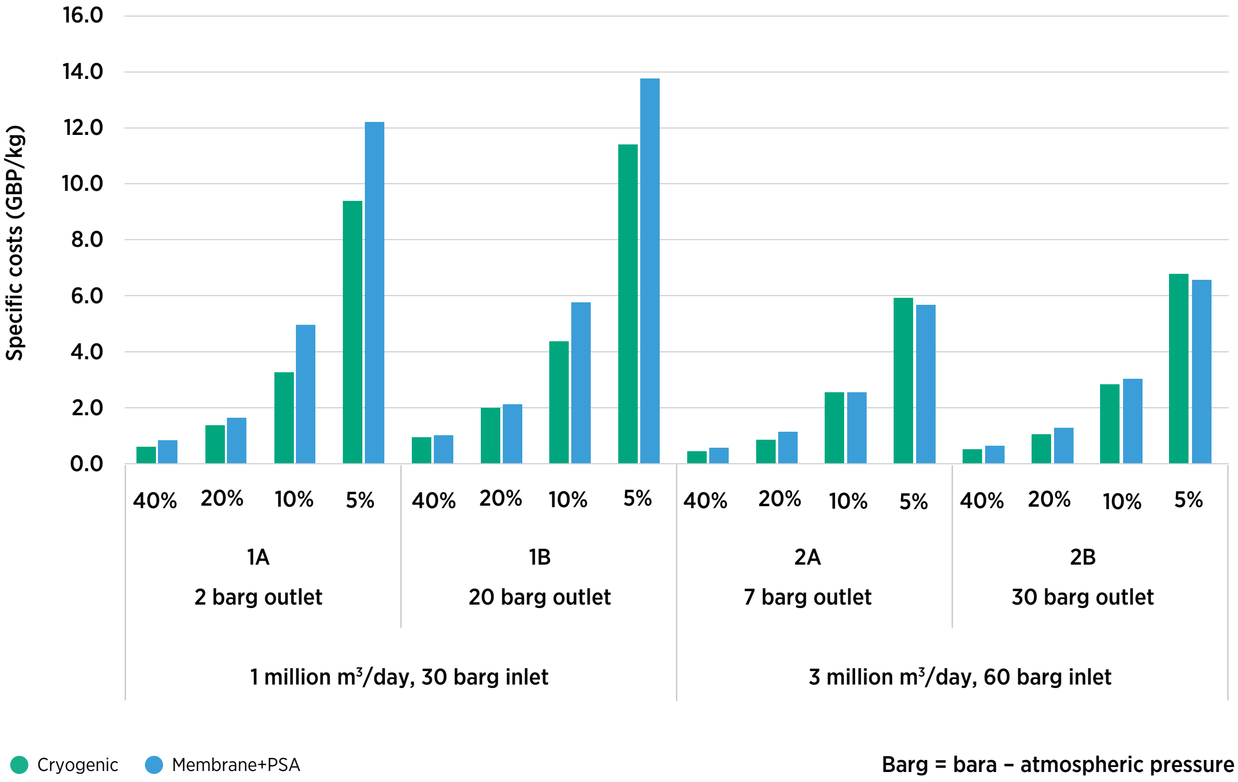


Hydrogen price (USD/kg) \ NG price (USD/GJ)	1	2	3	4	5	6
1	129	108	88	68	47	27
2	277	257	237	217	196	176
3	426	406	386	365	345	325
4	575	555	534	514	494	474
5	724	703	683	663	643	622
6	873	852	832	812	791	771

Note: Colour scale indicates cost level; green is low and red is high.

- **Purity loss.** Once the hydrogen is mixed into the grid, it cannot be directly used as hydrogen (e.g. for fuel cells). There are multiple technologies available for separating the hydrogen from the natural gas (e.g. pressure swing adsorption, membranes, cryogenic separation), but this comes at a relatively high cost that makes it unattractive. The cost is at least USD 1.5/kg in the best case and around USD 7-8/kg for a more realistic case (see Figure 5.3) (ENA, 2020; NREL, 2013). Even after separation, the hydrogen purity is not sufficient for fuel cells and an additional cost needs to be incurred for a polishing step.

FIGURE 5.3. Levelised cost of hydrogen separation from blended mix for different technologies and conditions



Source: ENA (2020).

- **Gas quality.** One factor introducing variability is the seasonality of gas demand in most countries led by the demand for residential heating. This means gas demand fluctuates while hydrogen supply remains fixed and will lead to variable hydrogen content over the year. The other main factor is that if hydrogen is produced with electrolysis, hydrogen injection will be subject to the variability of the renewable electricity input, leading to variations in hydrogen content over time that not all gas users can tolerate. This can be attenuated with gas storage close to the injection point at the expense of introducing an additional cost penalty.
- **Regulation.** Given the temporal variability of the hydrogen content, regulation would need to be introduced over a relatively short time interval to track compliance and ensure gas users are not negatively impacted. This can increase the costs of the regulatory framework or make compliance more difficult as such a fine temporal resolution is not in place for most systems.
- **Inconsistent limits across countries.** Blending limits vary significantly across countries and for many, hydrogen is not even defined in the gas quality standards. This represents an additional hurdle for global trade since all the countries involved in a specific path would need to have the same quality standards.
- **Technology maturity.** Blending is still at the pilot scale. There are multiple ongoing demo projects to prove its feasibility and it has not been proven at scale. This means that further research is needed before the option is fully available.

Based on the factors above, blending is not included in this analysis as the challenges outweigh the benefits.

Storage

At the project level, storage can help attenuate the variability introduced by wind and solar generation to achieve steady hydrogen production. This can be important for industrial users or users that require a high level of reliability (e.g. data centres). At the system level, it can increase resilience and energy security. When coupled with reconversion to power using gas turbines or fuel cells, it can help improve capacity adequacy and provide a long-term storage option to compensate for seasonal fluctuations of renewables.

Hydrogen's low volumetric energy density has consequences for storage. An underground storage facility that is converted from natural gas to hydrogen would store about a quarter of the energy (GIE, 2021). By the end of 2019, global natural gas storage (working) capacity was about 15.3 EJ (Cedigaz, 2020), which is equivalent to about 10% of global gas demand.[45] If all this were converted to hydrogen, the energy stored would be equivalent to about a third of current pure hydrogen demand or 5% of future demand (about 614 Mt). The advantage of repurposing these facilities would be the availability of seasonal storage at a relatively low cost of USD 0.2-0.3/kgH_2.

One challenge is that there are different types of reservoirs and not all of them are suitable for hydrogen. Salt caverns are the most suitable since there are no hydrogen losses and they can maintain high purities (HyUnder, 2014). There are already six salt caverns in the world that are used to store hydrogen (in Texas, United States, and Teesside, United Kingdom) (BNEF, 2019). Salt caverns, however, represent only 26% of the global deliverability of gas (Cedigaz, 2020), there are only about 100 sites operating across the world for natural gas and most of these sites (as well as the potential) are in North America and Europe. For example, Europe has a potential of nearly 83.5 EJ in onshore salt deposits[46] (Caglayan et al., 2020) and part of this potential would need to be tapped into to cover storage demand in 2030 since existing facilities are not sufficient (GIE, 2021).

In 2019, 80% of global working gas volumes were drawn from depleted oil and gas fields (Cedigaz, 2020). These (together with aquifers and rock caverns) could also be used for hydrogen storage. The challenge for these (especially for unlined rock caverns) is that they are porous rocks that hydrogen can permeate, representing losses. Numerical simulations indicate that these losses may be as high as 5% of the injected hydrogen if there is no cushion gas during the site development (Ebrahimiyekta, 2017). Hydrogen can also react with the formation resulting in methane production and the need for a purification system in case the hydrogen is for use in fuel cells. Using these porous formations requires further research (Ebrahimiyekta, 2017; Hassannayebi et al., 2019). Rock caverns are rarely used for natural gas (only 3 out of 150 caverns in the world [BNEF, 2019]) and further work would be needed to understand their suitability for hydrogen. After salt caverns, depleted gas fields and aquifers are the next best options (based on safety, technical feasibility and costs) (HyUnder, 2014). At the same time, conversion of gas storage is a lengthy process that can take anywhere between one and seven years, taking three to ten years for new storage assets. Some repurposing procedures can be standardised to streamline the process, so potentially this may decrease over time (GIE, 2021).

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[45] This ratio is higher for some regions. For instance, in Europe, the working gas capacity represents about a quarter of annual gas demand.

[46] Salt deposits are man-made by water injection in natural salt deposits.

Hydrogen's lower energy density compared to natural gas would also reduce the linepack of pipelines. This is the amount of energy that is stored in the pipelines themselves. It is subject to change based on pressure fluctuations, and can provide additional flexibility to the gas grid. This means less resilience against supply and demand fluctuations that will affect energy security, which needs to be compensated by a larger storage capacity.

5.2 Project pipeline

In the first nine months of 2021 more than 520 hydrogen projects were announced with a total investment of USD 160 billion. Of these, 51 were dedicated to infrastructure (distribution, transport, conversion and storage), totalling up to USD 20 billion (Hydrogen Council, 2021a).

In Germany, the government announced EUR 8 billion of investment in 62 projects across the entire value chain to develop large-scale hydrogen domestically. This funding was part of the IPCEI projects in the European Union. Of these projects, 15 were targeted towards infrastructure, potentially adding up to 1700 km of hydrogen pipeline (out of roughly 40 000 km of national natural gas transmission pipeline). Some of the relevant projects are listed here:

- AquaVentus is an initiative aiming to use 10 GW of offshore wind from the North Sea (in German waters) to produce hydrogen by 2035. It includes the AquaDuctus project, which refers to the hydrogen transport component, targeting 0.1 MtH_2/yr by 2030 and full capacity (about 1 MtH_2/yr) by 2035.
- GET H2 aims to establish a nationwide hydrogen infrastructure (along with production and storage). The first step is the GET H2 Nucleus project, which will connect Lower Saxony with North-Rhine Westphalia via a 130 km pipeline by 2024. Connection with the Dutch grid is envisaged by 2025, by 2026 it aims to integrate underground storage, and the realisation of the full vision reaching Salzgitter (Austria) is due by 2030. The GET H2 project is part of the TransHyDE project that also covers other modes of transport and carriers.
- Green Octopus aims to develop a hydrogen backbone connecting Belgium, the Netherlands and Germany, with links to France and Denmark, connecting existing ports to large inland demand centres. The network length is expected to be 2 000 km. The overall project investment is EUR 9.7 billion, also including 6 GW of electrolysis, 25 ships, 250 trucks, 20 refuelling stations and renewable generation.
- The "Doing hydrogen" project aims to build a 475 km network in Eastern Germany by 2026. Two-thirds of the network will use repurposed pipelines and one-third new.
- LHyVE project covers a 70 km hydrogen network around the region of Leipzig.
- The H2ercules project includes hydrogen production (1 GW of electrolysis), storage and transport from import terminals in the North to users in the West and South using 1500 km of transmission pipeline to be developed between 2028 and 2030.

The IPCEI projects are the first concrete steps towards investment and execution. The process started in January 2020 when gas transmission operators presented a vision of a national hydrogen network of 5 900 km, of which 90% would comprise repurposed natural gas pipelines. This was followed by the 2020 network development plan, which included hydrogen for the first time and estimated the need for 1300 km of hydrogen pipeline by 2030 (100 km of which are new hydrogen pipeline) for a total cost of EUR 660 million (FNB, 2020). In December 2021 a more detailed modelling exercise was completed using 63 GW of electrolysis by 2050. In such a future, a 13 300 km hydrogen network would be needed by 2050 (using 11 000 km of repurposed natural gas pipeline) at a total investment of EUR 18 billion (FNB, 2021). The planning for the next cycle (2022-2032) has taken this input into consideration and will be finalised in 2022.

Germany is also actively collaborating with neighbouring countries in projects for repurposing pipelines and transporting hydrogen. The MosaHYC project proposes a 100 km pipeline between France, Luxembourg and Germany at a total investment of EUR 85 million. Of this length, 70 km would use repurposed natural gas pipeline. The final investment decision for this project is expected by 2022, with commissioning in 2026 and a capacity of 60 000 tH_2 by 2030.

In April 2021 a feasibility study conducted by two transmission system operators (TSOs), one from Denmark and another from Germany, found that the two countries could be connected via a 340 km pipeline. Initially with a 2.5 GW capacity without the need for compression (assuming transport at 35 bar) for an investment of EUR 390 million, the pipeline would be expanded later to 8.6 GW (transport at 70 bar) using compression for an additional investment of EUR 280 million. About 50-60% of the network can use repurposed pipeline. The study also covered the potential trade between countries, estimating export capacity of up to 3 GW in 2030 and up to 6 GW in 2040 (GasUnie, 2021).

In the Netherlands, the decision to stop domestic production and phase out natural gas opens up an opportunity to repurpose pipelines for hydrogen as natural gas flows dwindle. GasUnie, the TSO, is aiming to build a 1400 km hydrogen backbone connecting five domestic industrial clusters and providing the transport capacity to export hydrogen to Germany. The first phase of the backbone in the northern Netherlands and connecting with northern Germany is planned for 2026. By 2028, all the national clusters should be connected and by 2030 interconnection with the broader European grid should be in place. About 85% of the backbone will consist of repurposed natural gas pipeline. The total conversion costs were estimated to be USD 1.65 billion (EUR 1.5 billion), with a split of roughly 55/45 between repurposed and new pipeline for a transport capacity of 10-15 GW (depending on the operating pressure). This grid was the focus of the HyWay27 project, which looked into three aspects including technology and safety, legal and financial aspects, and supply, demand and storage. Another pipeline (Delta Corridor) will connect Rotterdam with Chemelot (the Netherlands) and North-Rhine Westphalia (Germany) and is subject of a feasibility study ongoing by RRP (Shell and BP). In September 2021 the government announced a USD 7.4 billion (EUR 6.8 billion) package of various climate measures, of which USD 825 million (EUR 750 million) will be targeted at converting part of the existing natural gas infrastructure to hydrogen (Rijksoverheid, 2021). The transition started in 2018 when a 12 km natural gas pipeline connecting facilities belonging to Dow Benelux and Yara was repurposed for hydrogen and has been successfully operating since then.

In Spain and France, the Lacq hydrogen project will use 4.5 GW of electrolysis coupled with PV in Spain to produce hydrogen and transport it to France using repurposed pipeline for storage in aquifers. The hydrogen will be then used for reconversion to power in a combined-cycle plant from 2026 (Gas for Climate, 2021). Spain is also leading the Green Crane IPCEI and HyDeal projects aimed at producing hydrogen and exporting it to northern Europe. This project includes other aspects beyond transmission, such as renewable hydrogen production, underground storage (HyGeo project), transport of LOHC and hydrogen use for road transport, besides the hydrogen transmission component.

In the United Kingdom, "Project Union" explores the development of a 2 000 km network to connect the industrial clusters around the country by 2030 and would repurpose around 25%

of the current transmission pipelines (National Grid, 2021a). The project is at the feasibility stage and would start converting pipelines with a phased approach by 2026 (BEIS, 2021). FutureGrid is a testing facility that will support this project by testing different hydrogen contents, pressures and materials, and should be finalised in 2022 (National Grid, 2021b). The HyNet North West project aims to produce 30 TWh/yr of hydrogen from natural gas with CCS by 2030. The project includes underground storage with a capacity greater than 1 TWh across multiple salt caverns (in Cheshire) and 350 km of new hydrogen pipeline (HyNet, 2020). Another initiative is the set of H21 projects that looked into using natural gas with CCS for industrial and residential use. It started in 2016 with the Leeds City project concluding that conversion of the UK network to 100% hydrogen was technically feasible at a realistic cost (H21, n.d.). This was followed by the North of England project, which increased the scale by 13 times to reach 12.15 GW of production capacity and 125 GW of hydrogen transmission capacity to satisfy 85 TWh of annual demand. This included 520 km of pipeline at 80 bar and 334 km at 40 bar (H21, 2019b). Other projects within the initiative cover the distribution grid, testing, safety aspects, trials, conversion strategy and material compatibility.

In Europe, the Clean Hydrogen Alliance was launched in July 2020 together with the European Hydrogen Strategy. This platform aims to bring multiple stakeholders (industry, government and civil society) together to advance large-scale deployment of hydrogen. The work is organised in roundtables across six themes, one of which is transmission and distribution. One of its objectives is to facilitate investment in hydrogen, and as part of this the alliance has proposed 1 575 hydrogen deployment projects, 118 of which are for pipelines and 207 for transmission and distribution more broadly (including smaller pipelines, ports and shipping).

At the European level, 23 TSOs from 21 countries estimated that by 2030 the European hydrogen network could extend to 11 600 km, reaching 39 700 km by 2040. This would require an investment of USD 47-89 billion (EUR 43-81 billion), with 63-77% for the pipelines and the rest for the compressors. The network would comprise 69% repurposed pipeline. This would translate into transport costs of EUR 0.11-0.21/kg (Guidehouse, 2021b). Another study by 67 pipeline operators covering 58 000 km of gas pipeline[47] found that 70% of the onshore and most of the offshore network can be reused for pure hydrogen (Re-Stream, 2021). Snam, the largest TSO in Italy, claims that 70% of its current network of natural gas pipelines is compatible with hydrogen (Snam, n.d.). As part of the European recovery packages related to COVID-19, hydrogen could apply for USD 59.4 billion (EUR 54 billion) available to multiple clean technologies, while dedicated funding amounts to USD 13.2 billion (EUR 12 billion). Out of these totals, the share for transmission and distribution[48] is 3% and 5% respectively. Italy, France and Romania are among the countries with explicit support for hydrogen infrastructure (Hydrogen Europe, 2021).

Outside Europe, in Australia, the TSO (APA Group) announced a project to repurpose 43 km of natural gas pipeline in Western Australia. The project cost is USD 2.25 million (AUD 3 million), which includes lab testing of the material, development of safe operating guidelines and full-scale testing. Testing and research is expected to be completed in 2022.

[47] 28 800 km of onshore gas pipeline, 16 400 km of offshore gas pipeline and 12 900 km of onshore oil pipeline.

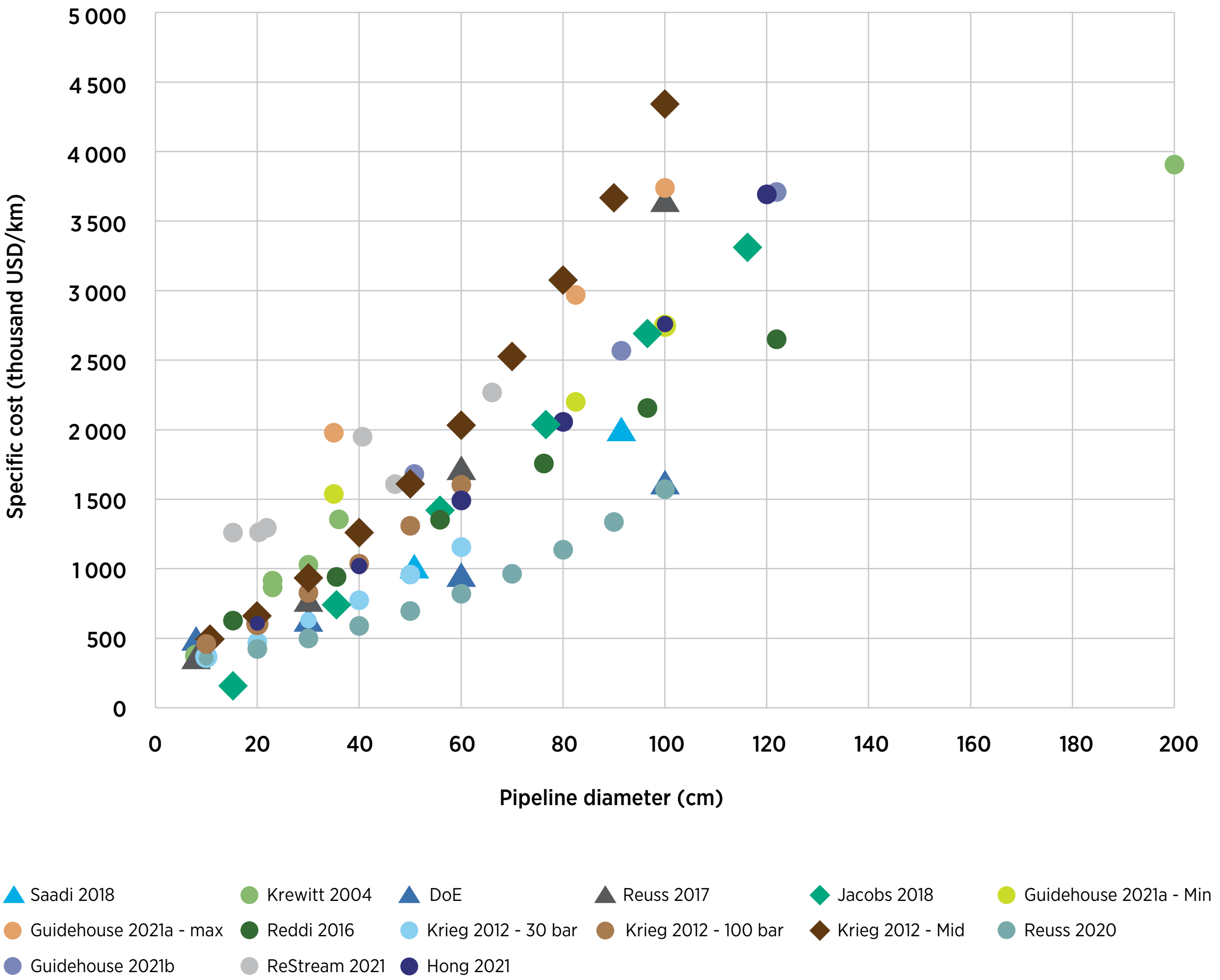
[48] Distribution includes trucks for transport and refuelling stations, so the category is not only for transmission pipelines.

5.3 Cost assessment

The main cost components are the pipeline, compressor, energy consumption (for compression) and cost of repurposing and replacing components such as seals and meters (if applicable). The investment needed for a new pipeline depends on its diameter and operating pressure. Increasing the diameter leads to a non-linear increase in steel used (the main factor determining the cost) and a non-linear increase in capacity. This means it is usually better to upsize the pipeline and design it for future capacity needs, leading to a larger pipeline as opposed to several smaller pipelines.

There is a relatively wide range of cost estimates for hydrogen pipelines (see Figure 5.4). Three key factors contribute to the difference across estimates. First, the designed pressure. Higher pressure leads to greater thickness, which in turn leads to more steel used and higher cost. The advantage of the higher pressure cannot be seen in Figure 5.4, which is a higher amount of energy transported for the same pipeline. This introduces a CAPEX vs energy transported trade-off. Second is the cost scope, which can range from the material only to covering the laying procedure, labour, right of way, management and contingency. Third is the implicit steel price used. In the last 10 years, minimum and maximum steel prices demonstrated on average a ratio of four. Since steel is the main contributor to the material cost of the pipeline, the point in time when the estimate is made can affect the result. Considering these factors, a new hydrogen pipeline can be 10-50% more expensive than a new natural gas pipeline (Cerniauskas et al., 2020; Guidehouse, 2020; Schoots et al., 2011).

FIGURE 5.4. Range of specific costs for new hydrogen pipeline as a function of inner diameter



Sources: DoE (n.d.); Guidehouse (2021a, 2021b); Hong (2021); Jacobs (2018); Krewitt (2004); Krieg (2012); Reddi et al. (2016); Re-stream (2021); Reuß (2020); Reuß et al. (2017); Saadi, Lewis and McFarland (2018).

For offshore pipeline, the investment cost is higher than onshore and the cost ratio depends on the water depth and specific diameter. Niermann et al. (2021) indicate a cost differential of 57%, the Hydrogen Council (2021b) estimates a factor of 1.3-2.3, d'Amore-Domenech, Leo and Pollet (2021) a factor of 2.3,[49] and Miao, Giordano and Chan (2021) a factor of almost three.

The most cost-effective option is repurposed pipeline (Cerniauskas et al., 2020), which can have an investment cost 65-94% lower than a new hydrogen pipeline (Guidehouse, 2020; HyWay, 2021; Re-Stream, 2021). For a small diameter, the pipeline itself can be almost 98% of the capital cost, while the compressor costs become more relevant at large diameters, reaching about half of the cost if a repurposed line is considered (see Figure 5.5). In contrast, compressor costs become a small fraction of the total cost when new pipelines are needed. The fixed cost (e.g. maintenance) is about 13-15% of the total cost. The electricity cost will largely depend on the diameter and the specific choice of distance between compression stations and pressure profile. For small

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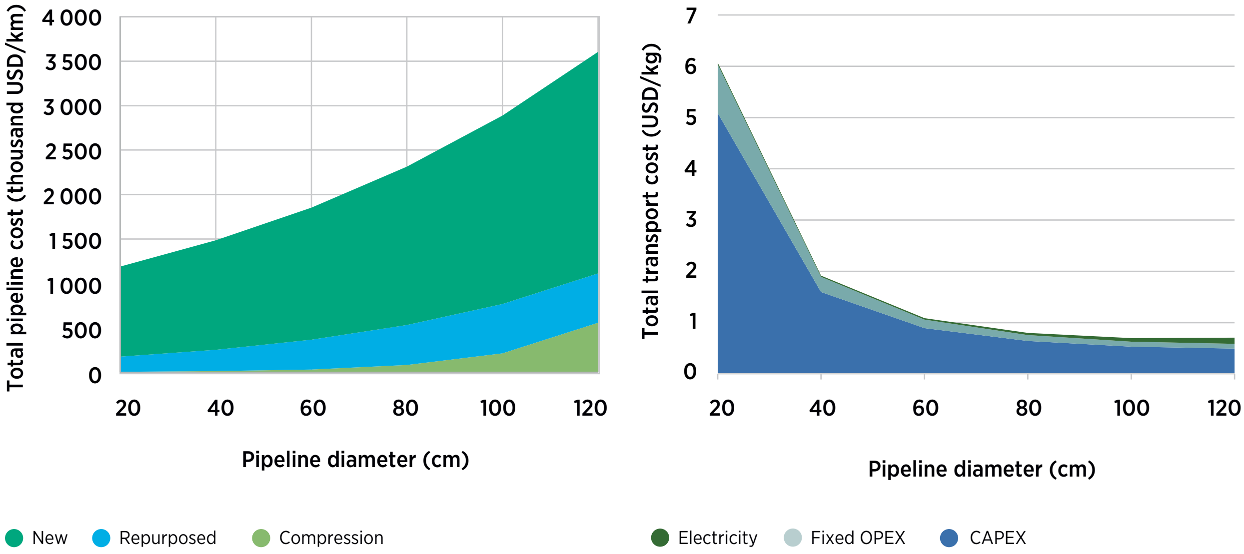
[49] A factor 1.3 for offshore in shallow water vs onshore infrastructure and a factor 2.3 to correct the cost from shallow water to deep water.

pipelines with small flows, the electricity can be about 0.5% of the total transport cost. For large pipelines with a higher velocity, the cost share can be as large as 15%.

Another cost that can become significant when repurposing is the cleaning of the pipeline and preparation for use, which can represent up to 35% of the total investment for reuse. This alone, however, still represents only about 10% of what an entirely new pipeline would cost (HyWay, 2021). Considering all the costs, the ReStream project found that the cost savings from reusing natural gas pipeline ranges from 75% when the network is fully based on repurposed pipeline (costs mainly coming from compression) to about 20% when the share of new pipeline is 70% (with a linear behaviour for shares in between) (Re-Stream, 2021). A disadvantage of repurposing is that the pipeline might need to be operated at a lower pressure to decrease the likelihood of cracks propagating. This translates into a larger volume and lower energy transported, increasing the cost per unit of hydrogen and compression costs.

FIGURE 5.5. Capital cost of a hydrogen pipeline (left), and total transport cost (right) by cost component



Notes: Right figure is for 5 000 km.
Source: Guidehouse (2021a).

A pipeline project within a country can take two to three years from final investment decision to commissioning. This can be much longer for cross-border pipelines and once the planning period is also included (rather than only construction). For instance, planning for Nord Stream I (a 122 cm, 1 200 km offshore pipeline from Russia to Germany) started in 1997 with the feasibility study carried out in 2001, the construction only beginning in 2010 and commissioning in 2011.

There is a trade-off between compression and pipeline cost. A larger pipeline can be used, increasing the pipeline cost, with the benefit of a smaller pressure drop and lower compression needs. Furthermore, another optimisation parameter is the distance between compression stations. Both of these parameters need to be optimised for the specific operating conditions.

6

COST COMPARISON BETWEEN ALTERNATIVES

COST COMPARISON BETWEEN ALTERNATIVES

Highlights

From a cost perspective, ammonia is the most attractive carrier for shipping hydrogen. In an optimistic scenario with an accelerated development of global hydrogen trade and innovation, the total transport cost of ammonia, including (re)conversion, can be 7-23% lower than liquid hydrogen and LOHC across a distance of 10 000 km. The major cost component for ammonia is the heat supply for cracking, which can be 30-40% of the total cost. In the worst case, this heat could be provided by the transported hydrogen and in the best case by waste heat from a neighbouring process. If this cost is avoided by directly using ammonia, the transport cost could be lower than USD 0.5/kgH_2 in 2050 in the best case. Ammonia also has the lowest capital needs at about USD 2.5-3.1 billion for every 1 MtH_2/yr in the most optimistic scenario, which is 10-20% lower than LOHC and 65% lower than liquid hydrogen. The transport cost and total investment nearly double when considering less optimistic assumptions, highlighting the importance of innovation, collaboration and scale to be able to achieve the low end of these costs.

The transport cost will largely depend on the scale of the project and the transport distance. The full economies of scale are reaped with project sizes of 0.4, 0.4 and 0.95 MtH_2/yr for LOHC, ammonia and liquid hydrogen respectively. To put these values into perspective, 1 MtH_2/yr would be equivalent to a 10 GW electrolyser running about 60% of the year, or the hydrogen consumption of five commercial ammonia plants. These sizes can translate into a cost reduction of 10-40% when compared to a smaller scale of 100 ktH_2/yr and are much larger with respect to today's pilot projects. For short distances of up to 4 000 km, liquid hydrogen might be attractive. Liquid hydrogen can also offer larger economies of scale and be more attractive for larger projects. However, as the distance increases, the boil-off losses during transport (and storage) quickly add up, making ammonia the most attractive for the widest range of distance and size combinations.

The most cost-effective option changes when pipelines are introduced into the mix. Pipelines become cheaper at higher flows and can easily handle flows larger than 3 MtH_2/yr. Existing natural gas pipelines can also be repurposed for hydrogen, reducing the capital cost by 65-94%. Even with optimistic assumptions for shipping, pipelines are the most cost-effective for distances of 1 000 km for relatively small projects (0.3-0.4 MtH_2/yr) and up to 3 000 km for larger projects (1.5 MtH_2/yr). This cost advantage for pipelines is extended if either repurposed pipelines are considered (up to 9 000 km for large projects) or if shipping costs stay high (7 000-9 000 km). This also means a direct overlap with the conditions that make liquid hydrogen attractive (short distances and large projects). Thus, where there are existing pipelines that can be repurposed, they can greatly decrease the costs. This might be an attractive option for Europe, North America and eastern China. For distances of 3 000-7 000 km that are connected by land, pipelines can be the most attractive, leaving ships for countries that are not connected by land, that are too far or where geopolitical relations negate the possibility of land transport (e.g. South Korea).

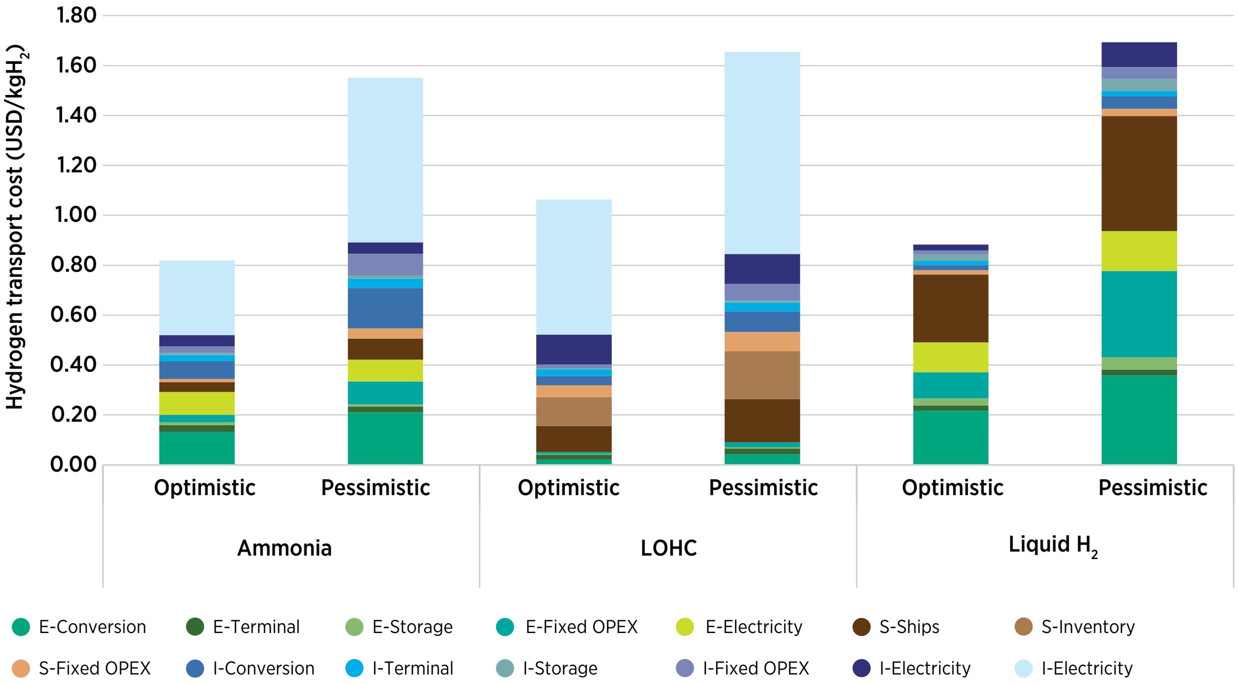
These cost comparisons are for a future where each technology's full potential has been reached. The reality today is still far from that, and there needs to be research, demonstration, scale-up and learning from deployment. Through these strategies, costs are expected to decrease by up to 90% when compared to today's pilot projects. The main strategy for achieving this is through scaling up the average plant size to reap the economies of scale. The main areas of progress for research and engineering are the energy consumption for hydrogen liquefaction, ammonia cracking and LOHC dehydrogenation; the costs of liquefaction and liquid hydrogen storage for large-scale applications; and mapping the materials used in existing natural gas pipelines to assess compatibility with hydrogen.

There are two choices when considering pathways for hydrogen trade: the specific carrier if shipping is used; and the choice between shipping and pipelines. Shipping and pipelines are not always possible. For instance, Japan and South Korea do not have any cross-border pipelines today. The nature of offshore pipelines significantly increases their costs (see Section 5.3), which changes the trade-off and leaves only shipping pathways as economically feasible alternatives. Similarly, landlocked regions or those with limited access to waterways only have pipelines as the feasible option. Thus, this chapter divides the comparison between alternative carriers for shipping (Section 6.1), and then between shipping and pipelines (Section 6.2), which is the second choice. Since this comparison will evolve over time as technologies progress, Section 6.3 explores one potential trajectory the technologies could follow and delineates some of the key uncertainties that could affect this trajectory.

6.1 Comparing hydrogen carriers for shipping

Using the data presented in previous sections, the total cost of transport for the three shipping pathways is shown in Figure 6.1.

FIGURE 6.1. Transport cost breakdown by hydrogen carrier, scenario and cost component in 2050



Notes: Costs are for a 1 MtH$_2$/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.

The transport cost has a relatively wide range of USD 0.7/kgH$_2$ to USD 2.1/kgH$_2$. To put this into perspective, the best locations in the world are expected to produce renewable hydrogen at around USD 0.65/kgH$_2$, while a location with average resources would have a production cost of about USD 1.5/kgH$_2$ (IRENA, 2022b). This means transport is nearly doubling the total delivered cost. Each of the carriers has one main component driving the transport cost.

Liquid hydrogen's cost is dominated by the cost of the ships. The need for cryogenic conditions and the special design of these ships leads to a specific cost (per tonne of hydrogen transported) that is seven to ten times higher than the cheapest ammonia carriers. Depending on the specific vessel design and velocity, boil-off losses can be 0.15% per day and not all of that might be needed as fuel for the ship, requiring further energy consumption for onboard liquefaction. Ammonia and LOHC have high energy consumption to recover pure hydrogen from the carrier. The assumption on how this heat is provided can drive the cost contribution. Different options are discussed below, stressing that this study follows the assumption that renewable energy has a cost of USD 60/MWh.

- The least conservative is to assume that waste heat will be available and that these processes can be integrated into others. One problem with this assumption is that the heat temperature required is relatively high (500-550°C for ammonia and 200-350°C for LOHC). For most industrial processes, a stream at this temperature level is usually either integrated in the process already (e.g. to preheat a stream) or used for power generation (through steam generation) and it is seldomly just released to the environment. This means there will be a trade-off for using such a stream (e.g. lower power generation that needs to be replaced with renewables) rather than being freely available for hydrogen. Another problem is the amount of heat that would be needed when importing large amounts of hydrogen. For instance, for the import of 1 MtH_2/yr, assuming energy consumption of 10 kWh/kg, 10 TWh of medium- to high-temperature[50] heat would be needed. To put this into perspective, global industrial heat consumption is about 85 EJ/yr, out of which about 70% is medium or high temperature (IEA, 2017). This would be equivalent to about 16 500 TWh, which is orders of magnitude higher, but most of that heat is already used or is actually needed for the process (e.g. steel production). A final problem is that the industrial sources where such waste heat comes from should ideally be close to the reconversion plant (to prevent heat losses), which limits the locations where the plant can be.

- Related to the above, one configuration is where hydrogen is used for power generation (e.g. the Japanese case) and part of the waste heat from combustion is used for hydrogen recovery. While this might work in terms of temperature level, a limitation is that usually all the heat is used for steam production and to drive turbines for power generation. Any heat that is instead used for hydrogen production will translate into lower power generation, increasing the cost per MWh produced.
- The most conservative is to assume that the heat comes from the hydrogen itself. Hydrogen can be burned to obtain high-temperature heat in the same way natural gas is used today (although further de-risking is still needed) (Hy4Heat, 2020). This can represent a high energy penalty, especially during the early stages of deployment, and be the equivalent of up to 40% of the energy contained in the hydrogen. At the same time, this also distributes the costs over a smaller amount of hydrogen delivered. With such a high penalty, costs can increase by two thirds when expressed in USD/kgH_2. For ammonia cracking, pressure swing adsorption could be used to purify the stream. The hydrogen recovery of this process is 15-25%, with the rest of the hydrogen ending up in the off-gas that can be used to provide the heat. Thus, providing heat from the hydrogen produced might be the preferred choice for this process configuration (Ishimoto et al., 2020).
- The heat could also be provided by electricity, which can in turn use renewable energy. This pathway has two main problems. First, the required temperature level, especially for ammonia cracking, is beyond what could be provided by heat pumps. Other technologies such as infrared heaters, microwave heaters, induction furnaces, resistance furnaces, electric arc furnaces or plasma technology would be needed. Not all these technologies are fully commercial and some (e.g. plasma technology) are only established in a specific industry (Madeddu et al., 2020). This means that depending on the technology, more de-risking and R&D is needed before it can be applied. Second, the importing region typically has limited low-cost renewable energy, which means this use would displace some other energy uses that might in turn be replaced with more imported energy, or that the cost of providing the heat is relatively high, still incurring in a high cost penalty on the overall transport cost.
- Most high-temperature heat is currently provided by fossil fuels. Another option may be to keep this technology, but add CCS to the flue gas. A disadvantage is that the flue gas has a low CO_2 partial pressure (0.04-0.1 bara), which translates into a relatively high capture cost (USD 50-100/tCO_2) (IEA, 2020b). This option would also need the availability of CO_2 storage capacity, which is not evenly distributed across regions (e.g. an energy importing region such as Japan has limited capacity, see [IRENA, 2022a]). This option also implies the

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[50] A common convention for heat is low temperature (< 150°C), medium temperature (150-400°C) and high temperature (> 400°C) defined according to the type of processes generating and using the heat and technologies.

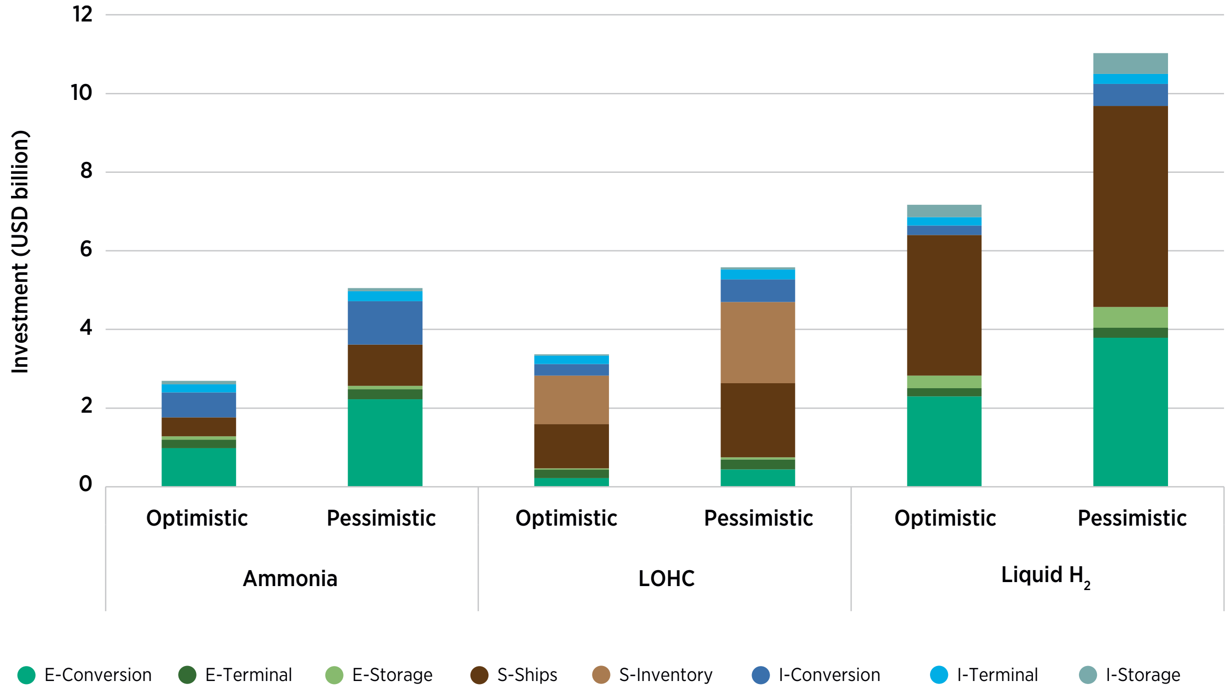
availability of natural gas, which many regions import today (e.g. Europe, South Korea and Japan). Therefore, this would mean reducing their energy independence and still relying on gas imports to satisfy demand.

The uncertainty in the techno-economic data leads to almost a factor two difference between the *Optimistic* and *Pessimistic* scenarios. This shows the importance of research and globally co-ordinated action for two reasons. First, to ensure that lessons learned from deployment are considered for new designs (a global learning-by-doing rate). And second, to establish global value chains where each component is manufactured in the location with the best conditions (e.g. low labour cost or high technology knowledge). This shows that the path followed towards 2050 and technology evolution do have a great influence on the expected cost in 2050.

Comparing the costs between alternative carriers, capital cost for conversion is the highest for liquid hydrogen by a factor of about two compared to ammonia and almost ten compared to LOHC. Energy consumption is also the highest for liquid hydrogen, while LOHC hydrogenation even releases energy. Liquid hydrogen ships are three times more expensive (in hydrogen terms) than LOHC ships and seven to ten times more expensive than ammonia ships (see Figure 6.2). These downsides for liquid hydrogen are compensated at the receiving port, as liquid hydrogen has the simplest process requiring the lowest capital with limited energy consumption (other than to pressurise the hydrogen). One big disadvantage that only LOHC have is that, by weight, they have the lowest hydrogen content of all carriers (4-7% of the weight is hydrogen while the rest is the carrier). This means that a single 110 000 t LOHC carrier transports roughly half of the hydrogen of a 60 000 t ammonia carrier. This translates into roughly double the number of ships that are needed to cover a specific route with the same annual flow and therefore double the capital cost of the ships. Considering the lower specific cost for LOHC ships compared to ammonia ships, but also the requirement for larger ships, the total cost is about 2.5 higher for LOHC. Another big disadvantage is that the cost of the carrier is significant. At the low end, the price for toluene may be USD 880, while DBT could be USD 4 400 (Niermann et al., 2019). Even considering a conservative price, the cost of the inventory in the ships is almost equivalent to the cost of the ships themselves.

Considering all these factors, from purely a cost perspective, ammonia seems to be the most attractive carrier. It has relatively low conversion costs, a high hydrogen capacity for the ships, no boil-off losses at any step and low costs of storage, with the main disadvantage being the heat requirement for the hydrogen recovery. Furthermore, ammonia is the only carrier that can be directly used in multiple applications with an existing established market. This can prevent the need for reconverting it to hydrogen, which is the most cost- and energy-intensive step.

FIGURE 6.2. Capital cost breakdown by hydrogen carrier, scenario and cost component in 2050



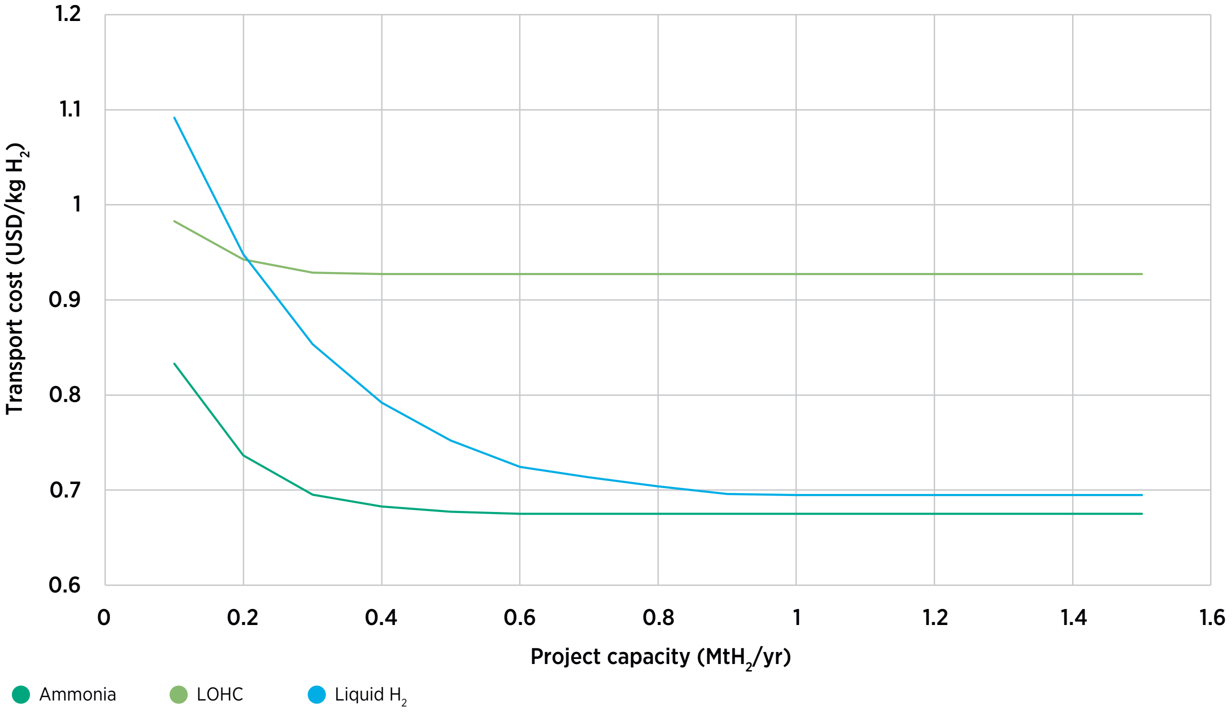
Notes: Costs are for a 1 MtH_2/yr export flow and a distance between ports of 10 000 km. Cost components are divided by part of the value chain: E = exporting country; S = ships; I = importing country.

Ammonia also has the advantage of requiring the lowest total amount of capital for a fixed hydrogen capacity, about 20% lower than the total investment needed for LOHC and 50% lower than liquid hydrogen. Liquid hydrogen has more expensive conversion, storage and ships, while LOHC requires double the number of ships, with another factor being the carrier cost. Liquid hydrogen has the advantage that the investment at the importing terminal is the lowest, which has the benefit of simpler design and less changes needed, but the disadvantage of the lowest benefit to the domestic economy. Across all carriers, the costs for storage, the terminal and even reconversion are relatively small when compared to the entire value chain.

Figure 6.2 can also provide an indication of the total capital that would be needed for a global supply chain. In the most optimistic case where ammonia is used, the capital ratio is about USD 2.5 billion for every 1 MtH_2/yr of exporting capacity (for 5 000 km). By 2050, global hydrogen production is expected to be in the order of 600 MtH_2/yr. Even trading 15-20% of this flow would imply a capital requirement of USD 225-300 billion. To put this into perspective, global investment in electrolysers (which are expected to provide about two thirds of the global supply) is almost USD 2.4 trillion (IRENA, 2021a).

The figures above have been used to make the comparison among carriers. However, the absolute costs are largely defined by two factors: project size, which affects the economies of scale for all the equipment, and distance between the two ports, which affects the fuel consumption, and the boil-off losses (for the case of liquid hydrogen). The effect of economies of scale is shown in Figure 6.3, while the effect of distance is shown in Figure 6.4.

FIGURE 6.3. Transport cost by carrier as a function of project size for a fixed distance of 5 000 km in 2050



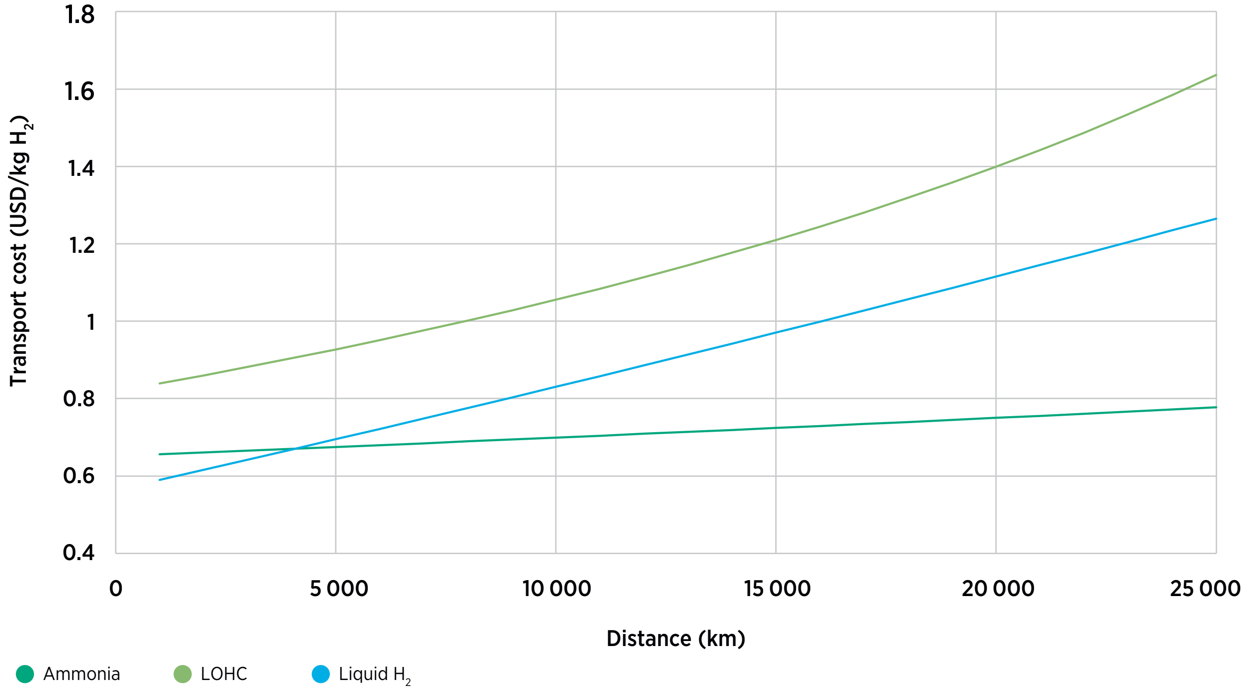
Note: Optimistic scenario for costs.

As regards economies of scale, a project capacity of 0.4 MtH$_2$/yr is enough for LOHC to reap most of the benefits. This is a direct consequence of the maximum scale that is considered as feasible by 2050. The maximum ship size is 110 000 t based on the data available and the typical size of oil carriers. The most common ships for crude oil and refined products are Long Range, which have a deadweight of 45 000-80 000 t (LR1) or 80 000-160 000 t (LR2). AFRAMAX ships are also common and are 80 000-120 000 t (EIA, 2014). A project of about 70 000 tH$_2$/yr would be enough to justify the use of the larger carrier (for 5 000 km). For (de-)hydrogenation, the largest capacity that has been considered so far is 0.3 MtH$_2$/yr (Nikkei, 2021). While this capacity target is for 2030 and it is expected that by 2050 larger capacities will be possible, not all the capacity increase could translate into cost reduction as it could lead to the use of parallel equipment (e.g. reactors) rather than just larger equipment. This might also be good for reliability and maintenance purposes by avoiding reliance on single pieces of equipment. So that is why there is hardly any cost benefit beyond capacity of 0.3-0.4 MtH$_2$/yr for LOHC. This boundary could change if these maximum sizes, when economies of scale can still take place, are beyond the limits assumed. For instance, there are ultra large crude carriers (ULCCs) that can carry 320 000-550 000 t of crude oil and still exhibit economies of scale, with the downside that not all ports around the world would be able to handle such ships.

Similarly, for liquid hydrogen, the maximum liquefaction capacity is assumed to be 2 500 t/d. This is far higher than what is available today, but would represent a similar capacity increase ratio to the one experienced by LNG from its early days until today (Steuer, 2019). This capacity is reached when the project capacity is about 0.95 MtH$_2$/yr. Beyond that, multiple trains in parallel would be used. For the ships, an annual capacity of 150 000 tH$_2$/yr would be enough to justify the use of the largest ship (assumed to be 160 000 m^3, equivalent to 11 360 tH$_2$) for 10 000 km. Given that the cost contribution of liquefaction is significant, that is why the cost reduces by over 40% when scaling up from 0.1 MtH$_2$/yr to 1 MtH$_2$/yr.

Ammonia is somewhere between LOHC and liquid hydrogen. The maximum assumed capacity of 5 000 t/d for a single ammonia train would be reached with a project of 325 000 tH_2/yr,[51] while the largest ship could be used when the plant capacity reaches about 135 000 tH_2/yr. After such scales have been reached, the benefits are in ship utilisation and storage sizing, but these are more limited compared to specific cost reduction.

FIGURE 6.4. Transport cost by carrier as a function of distance for a fixed capacity of 1.5 MtH_2/yr in 2050



Note: Optimistic scenario for costs.

The distance travelled has a directly proportional relationship with the energy consumption, which in turn is a function of power and vessel speed. Ammonia turns out to be the most attractive as the distance increases. It combines a lower total weight than LOHC, which translates into a smaller engine size (by almost a factor of two) without the boil-off losses that liquid hydrogen has. Conversely, fuel cells used for liquid hydrogen are a few percentage points more efficient than the internal combustion engines that would be used for ammonia, and liquid hydrogen ships weigh less than ammonia ships resulting in a smaller engine. The main limitation liquid hydrogen has is that with a longer distance, more ships would be needed to maintain a constant flow, increasing the total cost and favouring ammonia, which uses cheaper ships.

These two parameters (distance and project size) can be varied independently and the carrier with the lowest cost can be identified for each combination. Figure 6.5 shows this for both scenarios for 25 000 km and 1.5 MtH_2/yr. These values were chosen to cover the entire range of possibilities. Figure 6.3 shows that there are limited economies of scale beyond this point (even at a smaller scale). The longest route considered in the study is Chile to the Rest of Asia (23 300 km) and most of the routes are in the 7 000-16 000 km range.

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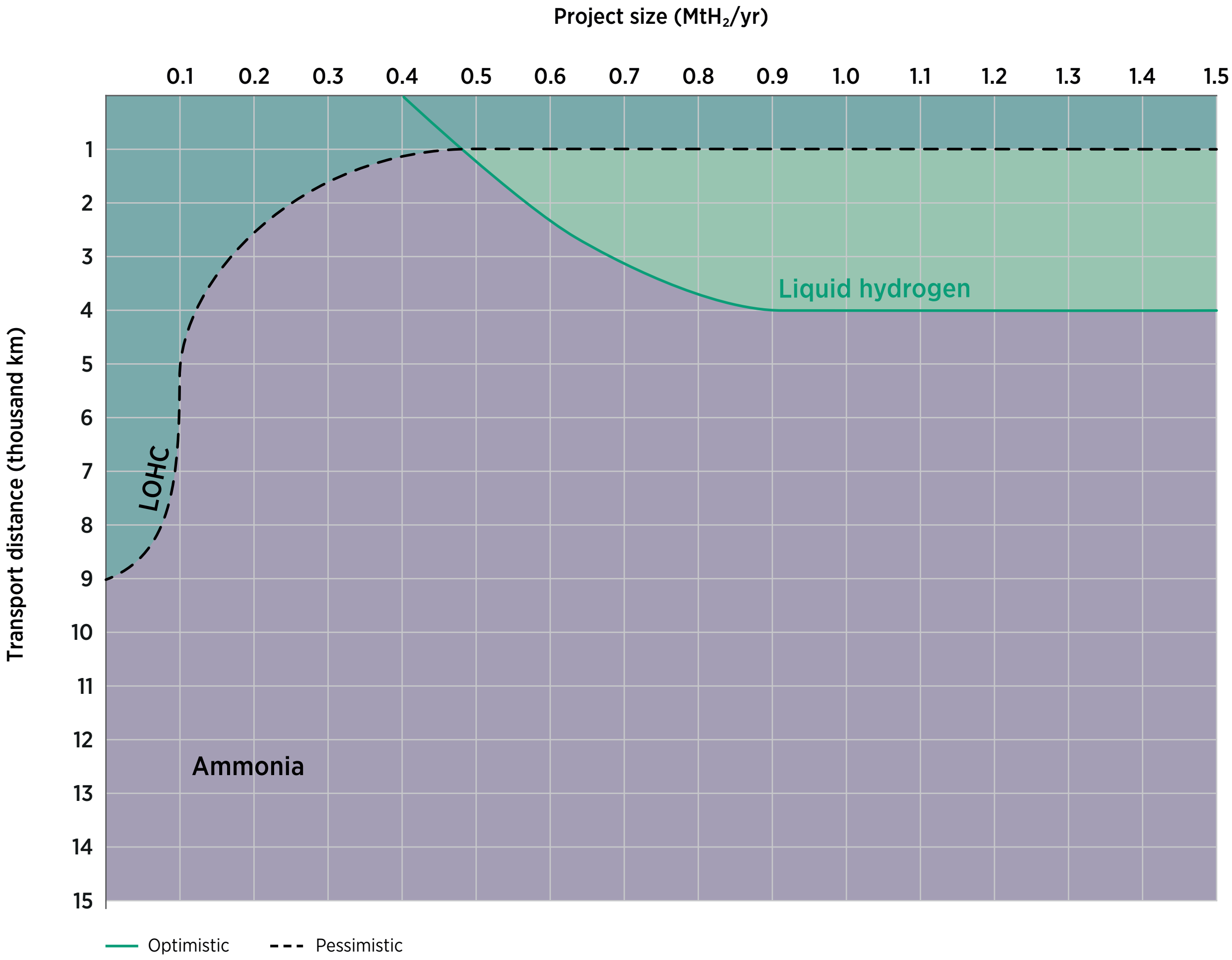
[51] Assuming the ammonia synthesis has limited flexibility and runs almost continuously. Flexible operation will reduce this flow.

FIGURE 6.5. Lowest-cost carrier in 2050 for a variable project size and transport distance for an *Optimistic* scenario (solid line) and *Pessimistic* scenario (dashed line)



Notes: Area where liquid hydrogen is attractive disappears in a Pessimistic scenario and LOHC are not attractive in an Optimistic scenario.

For both scenarios, ammonia has the widest range of conditions where it is the most attractive carrier. As shown in Figure 6.4, longer distances favour ammonia, which explains why the bottom part of Figure 6.5 is dominated by ammonia. For short distances, large capacities tend to favour liquid hydrogen, which is expected to be able to achieve larger capacities and exhibit economies of scale up to higher total capacities. This happens in the *Optimistic* scenario, where the difference is more prominent for liquid hydrogen as it has a high capital cost contribution. For the *Pessimistic* scenario, LOHC is favoured since its cost is closer to ammonia and it can reach its maximum capacity more quickly.

The other factor is the cost differential between the options as technology development towards 2050 is uncertain. For the *Optimistic* scenario, the carriers are the closest for short distances and small plants. In such an area, the difference between the most expensive and cheapest carrier is about 20%. This increases to about 40% in the region of medium capacity and medium distances, and increases beyond 50% for distances longer than 20 000 km (only a few routes in the world [IRENA, 2022b]). For the *Pessimistic* scenario, the closest costs are in the region dominated by liquid hydrogen (large capacities and short distances). In such a region, the cost differential between the lowest (liquid hydrogen) and highest cost is less than 7%, so soft factors can have a large influence on the choice of carrier under these conditions since the costs are relatively close (IRENA, 2022c). The difference increases to more than 20% for projects smaller than 0.5 MtH_2/yr or distances longer than 10 000 km, and ammonia achieves 40-50% lower costs for the longer distances.

6.2 Comparing hydrogen pathways (shipping vs pipelines)

Some trading pairs (e.g. North Africa to Europe) have a choice between sea transport or pipeline. For these pairs, the comparison is not only between hydrogen carriers in shipping, but also extends to shipping vs pipeline. Of all the potential large-scale importers, this is most applicable to Europe. Hydrogen pipelines to South Korea and Japan are not considered economically feasible since the water depth would imply a high cost penalty. The Sea of Japan has a mean water depth of 1.8 km and maximum depth of 3.7 km. The Yellow Sea (to the west of South Korea to enable trading with China) is relatively shallow with 44 m average depth and maximum of over 150 m, but has other factors beyond cost to consider. The water depth is even greater to the east of Japan (Pacific Ocean). This is also in line with the status quo, as neither South Korea nor Japan have pipelines for energy imports. As for ships, the cost of hydrogen pipelines is a function of the project size and distance. The project size is the most significant since it directly defines the pipeline diameter used. The transport capacity of a pipeline increases by the square of the diameter (i.e. a non-linear relationship), while the costs scale linearly with the distance.

Figure 6.6 shows the cost comparison between pipelines and the different carriers for ships with a variable transport capacity. Pipelines exhibit the largest cost decrease as capacity increases, reaching levels below USD 1/kgH_2 after 1 MtH_2/yr. This would be equivalent to a capacity of 3.8 GW (assuming continuous operation). This also assumes a relatively low pressure drop, leading to a 98 cm pipeline. In real applications, there will be a trade-off between pressure drop (i.e. energy consumption for compression, which translates into an operational cost) and pipeline diameter (capital cost). This can lead to a smaller pipeline diameter (around 80 cm) for the same flow. Although the widest pipeline in the world has a diameter of 142 cm (gas pipeline between Yamal, Russia, and Europe), the largest common diameter is 122 cm (48"). This would be enough to carry about 13.5 GW (at 80 bar),[52] equivalent to about 3.5 MtH_2/yr. In this capacity range, new pipelines would achieve a lower cost than using ammonia or liquid hydrogen ships. However, when considering repurposed pipelines, they already become the lowest cost option by 0.3 MtH_2/yr (with a relatively small 45 cm pipeline). Hence, for regions that have existing gas interconnections, using repurposed pipelines (if materials allow it), might be the most attractive option. This could be the case for North Africa and Europe, where there are already multiple pipelines from Algeria and Libya to Spain and Italy with a cumulative capacity of 63.5 bcm (equivalent to more than 60 GW) (Timmerberg and Kaltschmitt, 2019). This would be more than enough capacity to satisfy the EU 2030 targets and provide low-cost hydrogen transport in the most critical phase for development.

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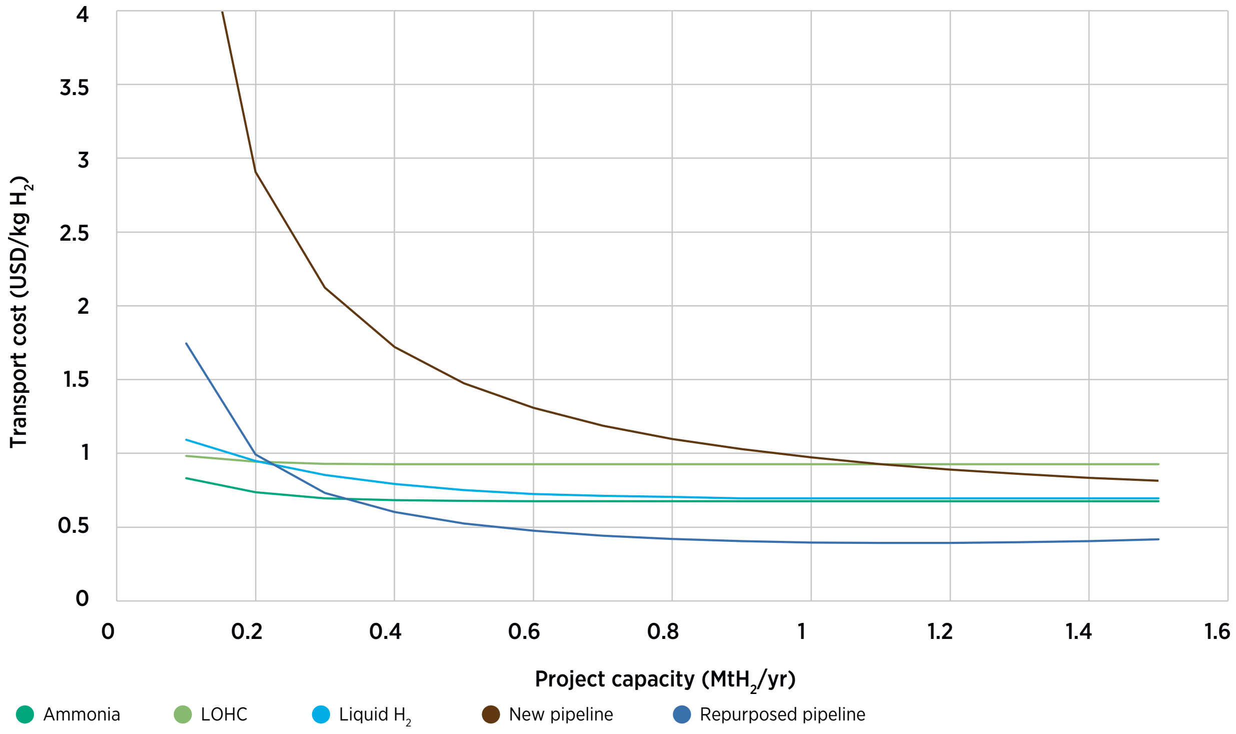
[52] Higher pressures translate into higher capacity, but it can also mean higher capital cost due to material selection.

FIGURE 6.6. Transport cost by pathway as a function of project size for a fixed distance of 5 000 km in 2050



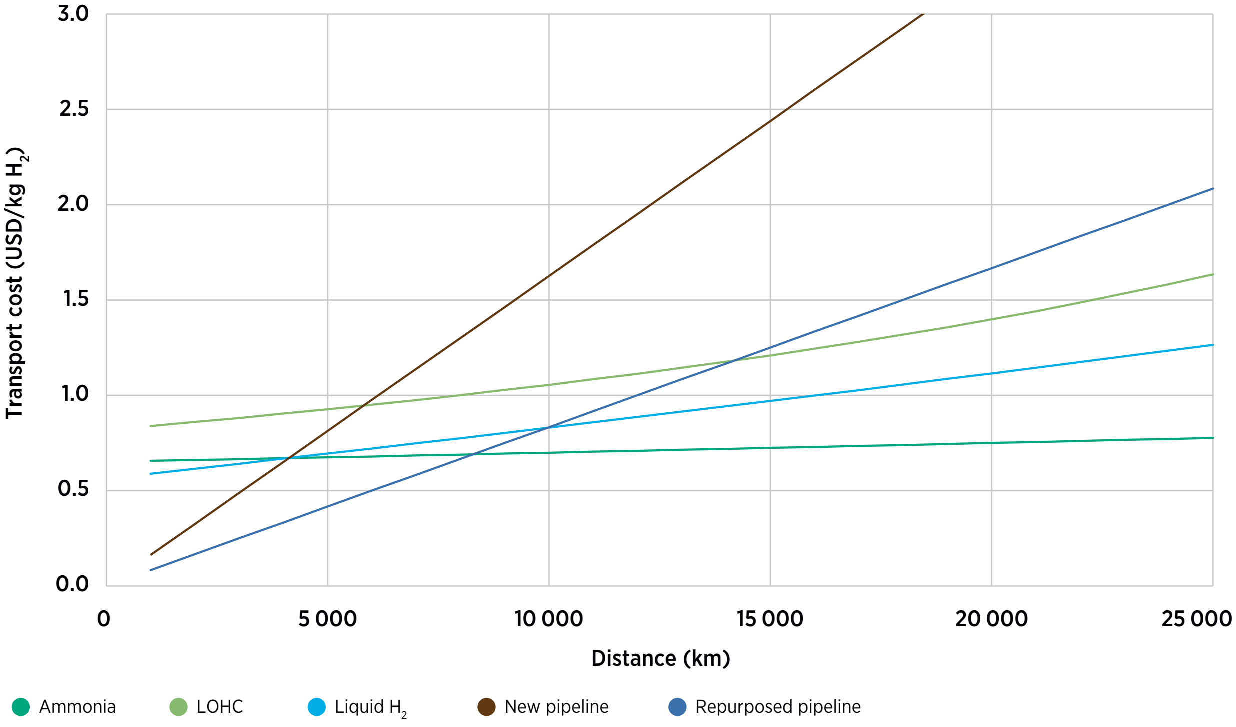
Note: Optimistic scenario for costs.

The other main parameter affecting the cost of a pipeline is distance. Figure 6.7 shows the cost comparison between pipeline and shipping for a fixed project size of 1.5 MtH_2/yr (equivalent to 5.7 GW at an 80 bar transmission pressure). The cost increase for pipelines is linear. The longer the route, the more steel is needed for the pipeline and the more compression is needed to transport the gas.

The main differences with ships are twofold. First, the base cost for a pipeline is relatively small, being represented only by a compressor to achieve the operating pressure of the pipeline (70-100 bar). In contrast, for ships the base cost of the conversion step, storage at the terminal, jetty and port facilities will all be the same regardless of the distance. These are non-negligible costs, which even in 2050 could be in the order of USD 0.5-0.8/kgH_2 (much higher today) for small flows. Second is the rate of the cost increase as the distance increases. For pipelines, every extra km means more pipeline and compression, while for ships larger changes in distance would be needed to justify the need for an additional ship (to maintain a constant supply). Furthermore, the energy density of the carriers in the ships is much higher than for compressed gas pipelines (see Figure 1.2), which is a factor of 11.5 lower than liquid hydrogen and a factor of 16 lower than ammonia. This means that ships can transport more energy and the energy consumption (defining the cost) is smaller per unit of hydrogen. This can be seen in the slope of each line in Figure 6.7.

Considering these two contrasting factors, pipelines are much more attractive for relatively short distances up to 4 000 km, while ships are more attractive beyond this. To put this into perspective, this distance would be enough to connect Saudi Arabia with Italy, the east to the west of the United States, or inland China to the coastal area. This distance almost doubles to 8 000 km when repurposed pipelines are considered. There are almost 1.4 million km of gas transmission pipeline around the world (CIA, n.d.) and while a reconversion to hydrogen requires an assessment of each pipeline, a large part of that could potentially be used for hydrogen. The distances for which pipelines are more cost-effective only extends in the *Pessimistic* scenario to about 9 000 km and 18 000 km for new and repurposed pipelines respectively. Thus, for all the cases in which pipelines are an option (i.e. connected by land), they are more attractive than ships. However, other factors beyond cost will also influence the pathway choice (IRENA, 2022c). For instance, a pipeline is a physical asset connecting two regions with a lifetime of 40 years or more, while a ship could have an offtake agreement of 10 years transitioning to a spot market afterwards.

FIGURE 6.7. Transport cost by pathway as a function of distance for a fixed project size of 1.5 MtH_2/yr in 2050

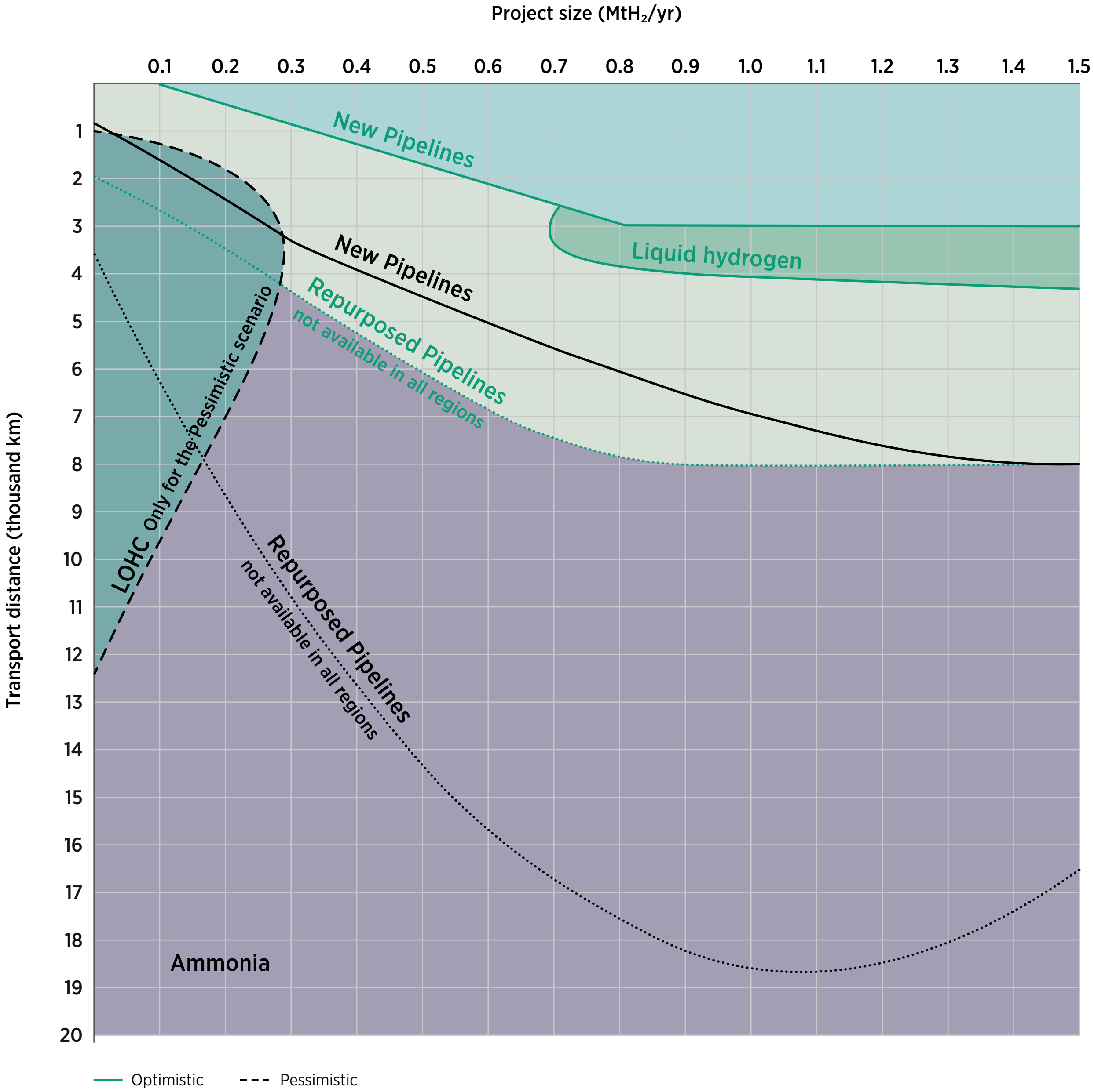


Note: Optimistic scenario for costs.

Figure 3.1 showed that ammonia is the most attractive carrier for most distance and size combinations. Liquid hydrogen and LOHC are more attractive for either short distances or small volumes. When pipelines are introduced in this comparison, Figure 6.8 shows that most of this area, especially for short distances, is now covered by pipelines. Most of the space where liquid hydrogen was attractive is now replaced with pipelines. If repurposed pipelines are available, then the area where pipelines are attractive expands even to the area where ammonia was the most attractive carrier, reaching distances of close to 18 000-19 000 km as the volume increases. A further advantage pipelines have is that they are already de-risked and do not have to go through experience curves. They are very similar to natural gas pipelines and there are already over 4 500 km of hydrogen pipeline around the world.

In contrast, each carrier for shipping needs to reach demonstration in at least one step of the value chain (see Figure 1.3) and many of the steps need to be scaled up by several orders of magnitude to reach the scale needed for global trade. Therefore, pipelines would be preferred, except in cases where terrain does not allow for it (i.e. only transport by sea is feasible).

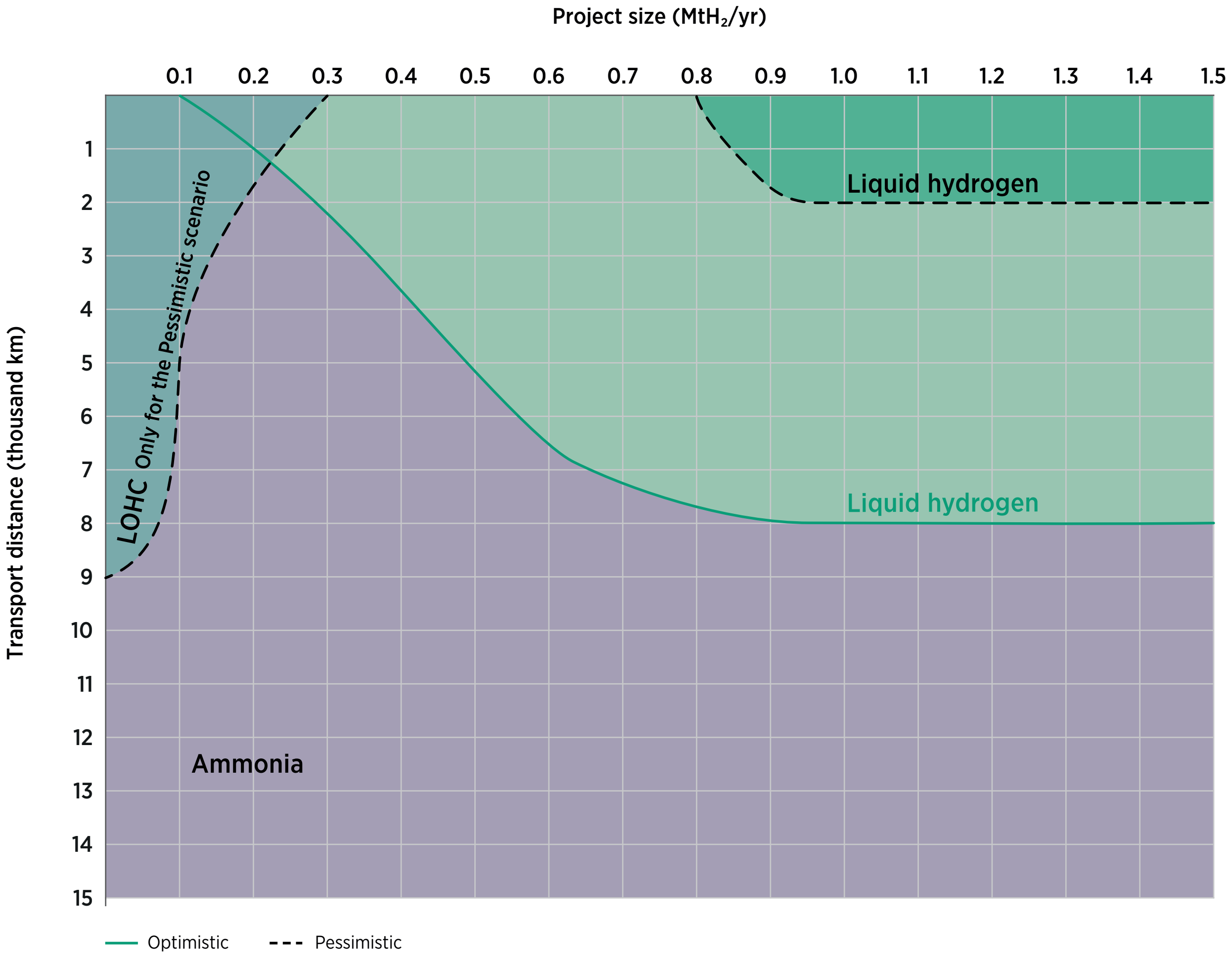
FIGURE 6.8. Lowest-cost pathway for a variable project size and transport distance in 2050, *Optimistic* scenario (solid line) and *Pessimistic* scenario (dashed line)



Notes: Area where liquid hydrogen is attractive disappears in a Pessimistic scenario and LOHC are not attractive in an Optimistic scenario.

As shown previously (see Figure 6.2), liquid hydrogen is the pathway with the highest investment needs, almost double the capital needed for ammonia (in both scenarios). This means the cost of capital will have a larger influence on the overall cost of liquid hydrogen. When the cost of capital changes from 7% to 3%, liquid hydrogen becomes attractive for up to 8 000 km (see Figure 6.9) and it even becomes an attractive carrier under the *Pessimistic* conditions. To put these values into perspective, this would be the difference in the cost of capital for utility-scale solar projects in 2021 between Turkey (7.4%) and France (3.3%). Taking solar as a reference, even values below 2% are possible (e.g. Germany and Australia) (IRENA, 2021e).

FIGURE 6.9. Lowest-cost carrier in 2050 for a variable project size and transport distance with a cost of capital of 3%



6.3 Potential technology development to 2050 and uncertainties

The comparison in previous sections focuses on 2050. Current costs are much higher. Principally three factors can influence the journey towards a lower-cost future: economies of scale, improvement in technology performance, and learning-by-doing.

For economies of scale, most of the technologies scale with a cost exponent close to two thirds (see Table 6.1). This means that doubling the capacity of a facility will roughly decrease the specific cost (cost per unit of energy delivered) by 20%. The main assumption for this is the maximum feasible size that is considered for 2050, which is achieved at 0.4, 0.4 and 0.95 MtH_2/yr of plant capacity for ammonia, LOHC and liquid hydrogen respectively (see Table 6.1). The main gap to close between today and such a future is precisely this capacity. Most pilot projects are currently just for a few t per year at most. The other factor is that R&D and technology de-risking needs to unlock those larger scales. While the transition from a large-scale ammonia unit today of 3 000 t/d to 5 000 t/d (see Section 2.3) might not be a drastic change, the scale-up needed for hydrogen liquefaction, ships and ammonia cracking can become a critical barrier if not addressed early.

TABLE 6.1. Cost scaling exponents for hydrogen carriers by step of the value chain

	AMMONIA	LOHC	LIQUID HYDROGEN
Conversion	0.65	0.667	0.8
Shipping	0.58	0.58	0.58
Reconversion	0.65	0.667	0.67

R&D for the improvement of technology performance could primarily address the largest element of energy consumption in each value chain. First, electricity consumption for hydrogen liquefaction is in the order of 30-36% of the energy contained in the hydrogen (see Figure 3.5). This may decrease on scaling up, changing the design and tackling the inefficiencies that have already been identified (see Section 3.3). However, there is still a long way to go to the *Optimistic* value of 6 kWh/kgH_2 assumed for this study. This is also in line with the *Ultimate* target from the US DoE (DoE, n.d.) and the target of the IDEALHy project in the EU (IdealHy, 2013b). Similarly, improved technology performance is needed for the heat consumption in ammonia cracking and LOHC dehydrogenation, which are expected to decrease by 35-55% if they are to reach the *Optimistic* values foreseen for 2050. Another area that could be improved through R&D, although with a more limited impact than the previous items, is the efficiency of the prime movers used in the ships. These are not expected to increase dramatically, but instead by a few percentage points.

The last factor is through learning-by-doing. This includes:

- Standardisation of the design that allows for easier replication and lower engineering and construction costs.
- Modularisation of the plants that allows construction of the modules in the manufacturing plant, which could be located in countries with low labour costs, reducing the cost of construction in places with high labour costs.
- Harmonisation of global standards leading to the same plant design across regions and being able to incorporate lessons from different parts of the world into a single design.
- Achieving large-scale manufacturing that makes the automation and process intensification of the manufacturing process attractive.
- Large-scale and global supply chains that enable companies that specialise in smaller components to build enough manufacturing scale.

The learning-by-doing effect can be studied by creating a relationship between cost and global capacity and by using a learning rate. With this approach, most of the cost decrease will take place at the beginning when global capacity is limited. Instead of a learning rate, an approximation is made using a cost differential between the nth-of-a-kind (NOAK) and the first-of-a-kind (FOAK) plants. These terms are used to denote that initial pilots and commercial plants (i.e. FOAK) usually have a tailored design, have limited previous references from which lessons can be learned to reduce costs, and can run into unforeseen issues during construction and operation. All these lead to a higher cost that gradually decreases with the subsequent plants, eventually reaching a steady cost by the "nth" plant.

Taking these factors into consideration, assumptions are made for each (see Table 6.2) to estimate technology performance over the coming decades (see Table 6.3). The rationale for the choices is as follows. From now until 2030, progress is mainly through R&D. Energy consumption has improved compared to current performance, but there is still a way to go to achieve the best values. Pilot projects have gone from scattered and one-off to a slightly larger scale reaching a few thousand t per year. This is still not enough to reach economies of scale, but at least offers the possibility of more continuous operation and having at least one (or a couple) of ships in transit. Technologies are still improving, and designs are not yet standardised, leading to additions and specific changes for every plant and the continuation of high costs.

By 2040, 20 years of R&D have been enough to lead innovations through the development funnel and go from lab to reality. The energy-intensive steps are well on their way to reaching the 2050 goals, but further work is needed to implement lessons from the already operating plants. Both governments and industry have developed some experience with global projects, which has decreased the perceived risks for these facilities and increased the capital flow for infrastructure. This has translated into a larger average size of projects, now in the 100 000 t/yr range, which allows capacities to go beyond where the largest cost penalty is incurred, but with room for further scale-up and cost decrease. Some parts of the value chain are being standardised and frontrunning manufacturers have built experience through earlier projects, which translates into lower costs.

By 2050, technology performance targets have been met. There might still be a gap between leading and laggard regions, technology suppliers and technologies of different vintage. This means the best available technologies meet the *Optimistic* targets, while some might only achieve the *Pessimistic* targets. The typical project is in the Mt/yr scale and the full benefits of economies of scale are reaped. This, in combination with the low production costs achieved by this time, leads to a low delivered cost, which makes the global trade economically sustainable and self-propelling. Experience from previous deployment waves has been translated into lessons and a standardised design reaching a NOAK cost.

As Table 6.3 shows, there is high uncertainty in the technology performance towards 2050. The specific values that are achieved in the coming 30 years will strongly depend on the choices and developments across the three dimensions described. Delay and poor progress will increase the chances of falling closer to the *Pessimistic* conditions, while accelerated and co-ordinated action will allow perhaps even the surpassing of the *Optimistic* scenario. These values just show the possible paths that could be pursued and the consequences of those two divergent paths.

TABLE 6.2. Cost scaling exponents for hydrogen carriers by step of the value chain

	2030	2040	2050
R&D (energy)	Mid-way	Fully reaped	Fully reaped
Project scale (‘000 t/yr)	10	100	1 000
Learning-by-doing	FOAK	Mid-way	NOAK

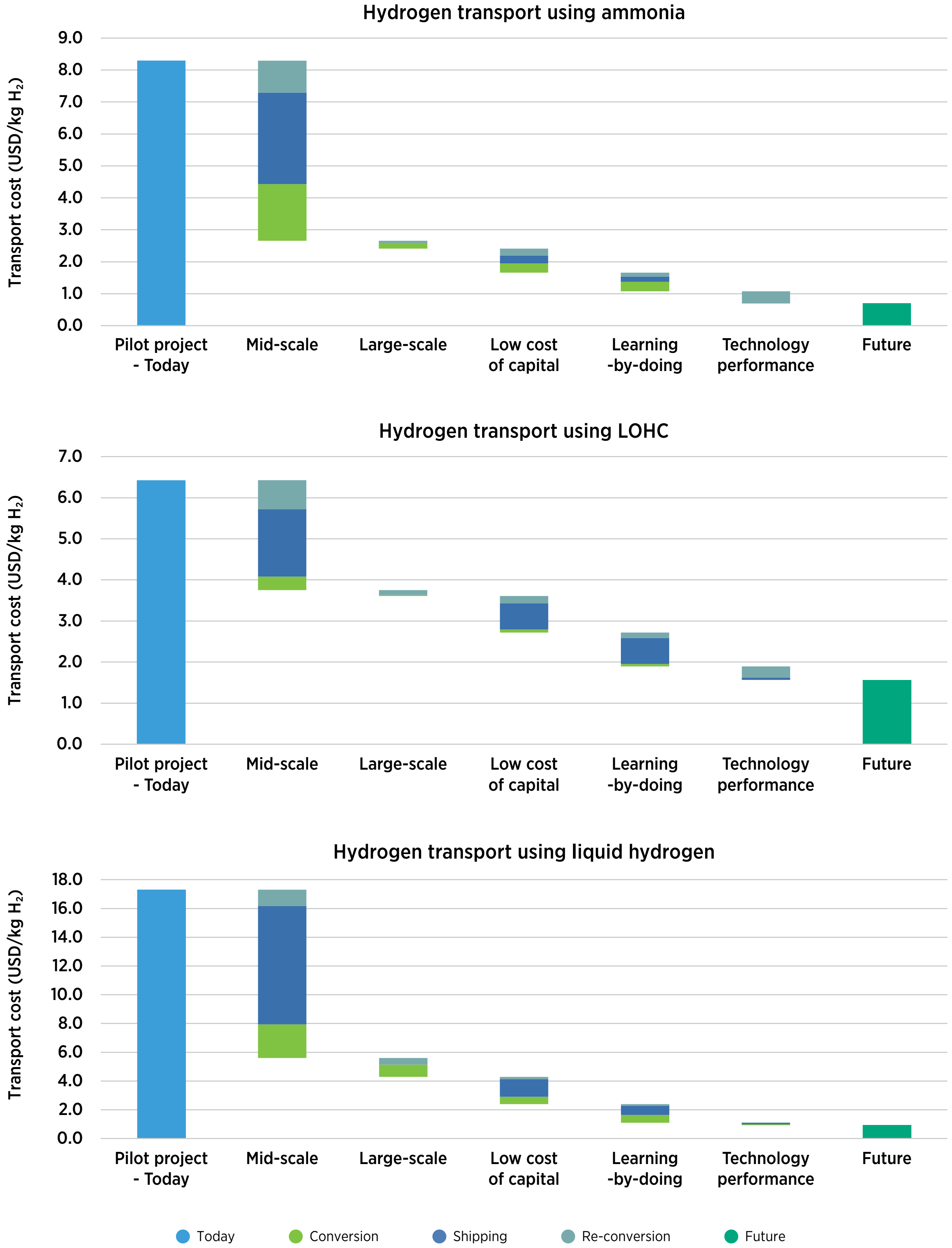
TABLE 6.3. Technology performance from 2030 to 2050 for hydrogen carriers

PARAMETER	UNITS	TIME HORIZON	AMMONIA OPTIMISTIC	AMMONIA PESSIMISTIC	LOHC OPTIMISTIC	LOHC PESSIMISTIC	LIQUID H_2 OPTIMISTIC	LIQUID H_2 PESSIMISTIC
Conversion								
CAPEX	USD/kW product	2030	987.0	1 973.9	225.8	451.7	1 860.5	3 683.8
		2040	440.9	881.7	92.3	184.6	1 033.0	1 704.5
		2050	292.7	585.4	58.2	116.4	603.4	995.6
OPEX	% of CAPEX		2%	2%	3%	4%	4%	4%
Efficiency	% LHV	2030	88%	87%	95%	90%	95%	95%
		2040	88%	87%	97%	93%	98%	98%
		2050	88%	87%	99%	96%	100%	100%
Electricity consumption	kWh/kgH_2	2030	4.3	4.3	0	0	8	9
		2040	3.3	4.3	0	0	7	8
		2050	3.3	4.3	0	0	5.5	7
Shipping								
Investment per ship	USD/t of carrier	2030	2 723	5 294	1 379	2 068	109 060	155 800
		2040	900	1 750	600	900	35 000	50 000
		2050	900	1 750	600	900	35 000	50 000
Power	MW	2030	5.4	5.4	13.8	13.8	2.6	2.6
		2040	19.7	19.7	34.5	34.5	5.4	5.4
		2050	19.7	19.7	34.5	34.5	5.4	5.4
Efficiency		2030	47%	47%	40%	40%	52%	52%
		2040	50%	50%	43%	43%	55%	55%
		2050	52%	52%	46%	46%	57%	57%
Reconversion								
CAPEX	USD/kWH_2	2030	783.4	1 524.7	416.4	1 087.8	365.6	933.3
		2040	310.8	604.9	178.0	465.0	150.5	384.1
		2050	199.1	354.0	97.0	242.5	60.4	190.5
OPEX	% of CAPEX		3%	4%	3%	6%	3%	4%
Efficiency	% LHV		98%	98%	98%	98%	98%	98%
Electricity consumption	kWh/kgH_2	2030	2	2	2	2	0.60	0.90
		2040	1.25	1.25	2	2	0.40	0.65
		2050	0.75	0.75	2	2	0.2	0.4
Heat consumption	kWh/kgH_2	2030	11.2	16.8	13.6	20.4		
		2040	8.1	14.0	11.3	17.0		
		2050	5.0	11.2	9	13.6		

Notes: CAPEX for (re)conversion do not include the storage and terminal costs which are considered separately in this study.

Figure 6.10 shows the influence of the main cost-determining factors. Furthermore, since there are currently no complete value chains integrating these technologies, the cost of capital is expected to be high compared to what could be achieved in the future.

FIGURE 6.10. Cost pathway from today until 2050 and contributors to cost decrease for ammonia (top), LOHC (middle) and liquid hydrogen (bottom)



Current transport costs range across USD 6.5-17.3/kgH$_2$. The main factor driving the high cost is the project scale. Pilot projects are not able to reach the maximum size for any component of the value chain, leading to much higher specific costs (see Table 6.3). This has the worst effect on liquid hydrogen, which requires cryogenic conditions that result in high capital cost. The ships and the liquefaction step represent most of the cost penalty in a small-scale liquid hydrogen value chain. Another factor contributing to a high cost for pilot projects is that if the hydrogen transported were to be used as a fuel for the ship, a relatively large fraction of the cargo would be consumed as the amount of hydrogen transported is small (although a smaller ship also leads to a smaller energy consumption). This decreases the amount of hydrogen that is finally delivered, increasing the specific costs. When the project increases to 100 000 tH$_2$/yr, the specific cost is already slashed by between 40% (LOHC) and 75% (LH$_2$). This level is still not enough to achieve the maximum capacity for the various steps in the value chain, but it is enough to achieve the largest benefits of economies of scale). It would be equivalent to an electrolyser of about 1.5 GW operating 50% of the time. This is large by current standards (the largest in the world is 20 MW), but is within the range of projects planned for the coming decade (e.g. HyDeal Ambition is aiming for 67 GW, a 45 GW project has been announced in Kazakhstan, and CWP Global plans to build a 30 GW Power-to-X plant in Mauritania). Further project size increases to 1.5 MtH$_2$/yr bring the cost of all carriers within the USD 2.4-3.6/kg range. This would already be in the same order of magnitude as the hydrogen production cost, so transport is no longer dominating the total delivered cost.

As projects are constructed, the level of knowledge across all stakeholders will increase, which will effectively decrease the perceived risk of these facilities. Assuming the initial projects have a very high risk and a cost of capital of 15%+, a reduction to 5% by 2050 (a conservative assumption given the experience with renewables) results in transport costs decreasing by 25-45%. Implementing lessons from deployment, standardising the design and, in general, going from individual projects that require specific design to a replicating approach can further reduce the costs by 35-60%. The largest benefit is for liquid hydrogen, which has the highest capital cost, so most of this cost reduction is for liquefaction and liquid hydrogen ships.

Improvement in technology performance is considered through lower energy consumption for ammonia cracking, LOHC dehydrogenation, hydrogen liquefaction and engine efficiency for the ships. The effect this will have will depend to a large extent on the assumption for the electricity and heat source. For Figure 6.10 a conservative assumption is used where electricity has a price of USD 50/MWh, reflecting the fact that it needs to be supplied almost constantly to the conversion unit, requiring the coupling with batteries and deviating from the electricity price used for the electrolysers. Similarly, it is assumed that the importing region has relatively expensive renewable resources and that the best resources have been used for domestic electricity production. Hence, heat is used, with a cost penalty of USD 60/MWh. Under these assumptions, the cost decrease for technology improvement is 35%, 19% and 15% for ammonia, LOHC and liquid hydrogen respectively to reach levels of USD 0.7-1.6/kg for the total transport cost.

The steps in Figure 6.10 are shown separately for illustrative purposes. In reality, these factors are highly intertwined and will most likely develop in parallel. And even when deployment data is available, it will be difficult to allocate cost reduction to individual factors (Egli, Steffen and Schmidt, 2018; Elia et al., 2020; Kavlak, McNerney and Trancik, 2018). While the largest single contributor to cost reduction is expected to be economies of scale, the potential of the other cost levers should not be overlooked, meaning that a focus on financing strategies, R&D and the supply chain is essential to achieve low costs in the long term.

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APPENDIX: INTERNATIONAL AND NATIONAL STANDARDS TO BE CONSIDERED DURING THE DESIGN OF LIQUID HYDROGEN CARRIERS

- IEC 60079-10-1: Explosive atmospheres – Part 10.1 Classification of areas – Explosive gas atmospheres.
- IEC 60079-29-2: Explosive atmospheres – Part 29.2 Gas detectors – Selection, installation, use and maintenance of detectors for flammable gases and oxygen.
- IEC 61982: Part 7 Electrical Installations – Hazardous Areas.
- ISO 11114: Compatible materials for hydrogen embrittlement resistant steels.
- ISO/TR 15916: Basic Considerations for the Safety of Hydrogen Systems.
- AIAA G-095-2004: Guide to Safety of Hydrogen and Hydrogen Systems.
- NFPA 2: Hydrogen Technologies Code.
- NFPA 55: Compressed Gases and Cryogenic Fluids Code.
- CGA G 5.4: Standard for Hydrogen Piping Systems at User Locations.
- CGA G 5.5: Hydrogen Vent Systems.
- ASME B31.12-2011: Hydrogen Piping and Pipelines.

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