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**Part 1: Basic elements for avoiding greenhouse gases and
generating climate-neutral energy
(technical toolbox)**

Chapter 2-5

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2.5.   Transport and storage of hydrogen

Introduction and relevance

The previous chapter focused more on the production of low-carbon hydrogen through electrolysis. For the overall consideration of possible hydrogen supply chains and for the determination of a potential market price for hydrogen produced in this way in the future, the additional analysis of the possibilities of transport as well as storage is crucial. As already mentioned, the following dilemma exists: In a country with a high share of solar or wind energy, hydrogen could be produced at low cost (< 2€/kg H_2) from renewable sources, because the required electricity can be purchased very cheaply from PV or wind plants there and the investment costs can be reduced by subsidies at the same time. However, if the import destination is associated with long transport routes and thus high costs, this could ultimately make the production of hydrogen uneconomical.

In general, a distinction must be made between the following modes of transporting hydrogen: Transport in its pure form, either gaseous or liquid, as an admixture, e.g. to natural gas with or without subsequent separation, or as a so-called derivative, i.e. a chemical compound that has been created from another (e.g. ammonia, methanol, LOHC). In the following, the individual transport modes of hydrogen are examined in more detail, together with the means of transport that are available (pipeline or ship). The focus is on supply chains of hydrogen carriers whose end use is the hydrogen and not the derivative. In addition, the present is not a literature review that classifies the topic of "hydrogen carriers" chemically and physically in its entirety, but rather exclusively depicts those that are suitable for transporting large quantities of hydrogen over longer distances. This is due to the fact that this part of the report is intended to show the academic status quo on the topic of the "globally networked hydrogen economy", for which the transport of large quantities of hydrogen from the producing country to an importing country is of particular relevance.

Various hydrogen transport options

In the following, we will first analyse the transport of hydrogen in its pure form, either gaseous or liquid.

2.5.1   Transport of gaseous hydrogen

Table 11: Relevant properties of gaseous hydrogen for transport.

Density	40 kg/m^3
Calorific value	39.4 kWh/kg
Print	700 bar
Volumetric energy density	1.57 kWh/l
Minimum ignition energy	0.019 mJ
Compression effort	4.05 kWh/kg H_2 (mean value)
Energy Penalty	10 % (HHV)

Hydrogen (chemically H_2) is the lightest element on earth, having a density of only 0.09 kg/m^3 at atmospheric pressure.[253] By comparison, the gas methane (CH_4), the main component of natural gas, has a density of 0.718 kg/m^3 under normal conditions. To transport the same amount of hydrogen by weight, a volume of 8 m^3 is required at the same pressure. One kilogram of gaseous hydrogen thus has a significantly higher volume than methane at atmospheric pressure (approx. 11.1 m^3 compared to about 1.4 m^3 for methane).
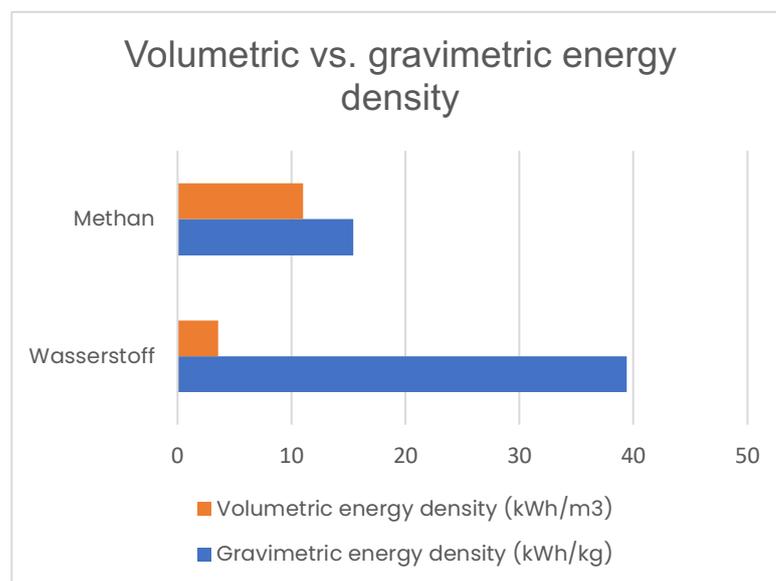
Figure 91: Volumetric and gravimetric energy densities of hydrogen and methane in comparison.

Source: Author

In the previous chapter, it was pointed out that hydrogen has a comparatively high calorific value (HHV) of 39.4 kWh/kg. For methane, this is 15.4 kWh/kg. Thus, more energy can be

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[253] The atmospheric pressure at sea level is 1013.25 hPa. This corresponds to about1 bar.
 The normal conditions under which densities of gaseous substances are specified also include a temperature of 0°C = 273.15 K

tapped per kilogram of hydrogen than per kilogram of methane, and its gravimetric energy density is higher. However, due to the properties of hydrogen described above, the volume-specific energy density of hydrogen is significantly lower than that of methane (see Figure 91). This is because, as described, 11.1 m^3 is needed to transport the energy quantity of 39.4 kWh in the form of hydrogen. If the same amount of energy were to be transported by methane, only 3.6 m^3 would be needed. The volumetric energy density of hydrogen is therefore about 3.55 kWh/m^3 and that of methane 11 kWh/m^3, although the gravimetric energy density of hydrogen is significantly higher than that of methane.

This brief classification shows why transporting hydrogen (but also methane) at atmospheric pressure is not a viable option. Too many tanks would be needed to transport an economically adequate amount of energy. In order to increase the volumetric energy density of gases and thus enable economic transport, compression is used. In practice, this means that the volume of the gas can be reduced by increasing the pressure. At a pressure of 700 bar, a density of 40 kg/m3 is achieved, 444 times the above-mentioned 0.09 kg/m^3 at 1 bar. This means a volumetric energy density of 1576 kWh/m^3 (1.57 kWh/l) compared to 3.55 kWh/m^3 (atm). The transport of one kilogram of hydrogen (or 39.4 kWh) thus requires a volume of 25 liters, significantly less than the previously mentioned 11,100 liters.

As shown in Table 8 the technically mature low-temperature electrolysis processes today operate at a typical pressure level of 10-30 bar for alkaline electrolysis (AEL) and 20-50 bar for polymer exchange membrane electrolysis (PEMEL). This electrochemical compression, in which the cell stack and associated components are pressure-tight and the formation of the product gases leads to the pressure build-up, reduces the downstream compression effort and increases the energy efficiency for the onward transport of the hydrogen. In theory, compression from 20 bar to 350 bar requires 1.08 kWh/kg H_2, or 1.48 kWh/kg H_2 from 20 bar to 700 bar.[254] In this case, the additional energy required for compression is correspondingly 2.75 % or 3.75 % (HHV). In practice, the energy required for compression can range from 1.7 to 6.4 kWh/kg H_2 and depends on the outlet pressures actually achieved, the efficiency of the compressor and potential leakages. [255]

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[254] See Khan et al., 2021b. Such high pressure is necessary, for example, for transport in hydrogen tanks in order to be able to transport as much energy as possible on the limited loading area of the transport vehicles.
[255] Cf. Khan et al., 2021b.
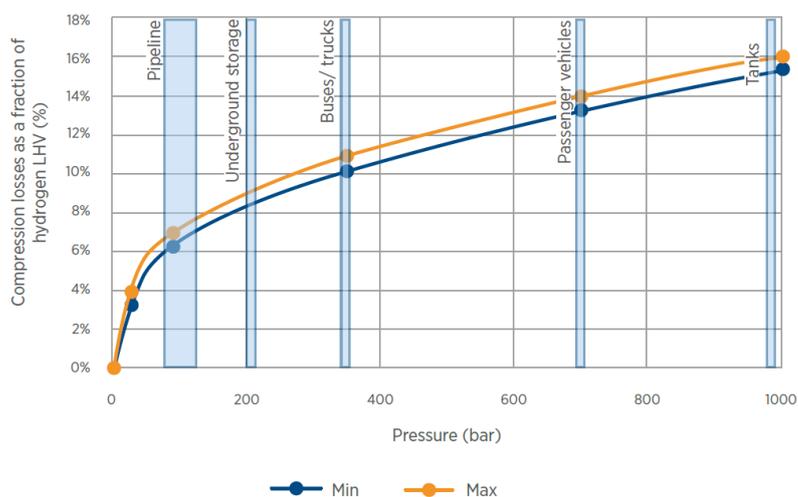
Figure 92: Energy losses due to compression loss depending on the transport form.

Source: IRENA, (2020).

Assuming the mean value of this empirical observation (4.05 kWh), the cost is about 10 % (HHV). These additional energetic costs are called the "energy penalty". If one wanted to transport energy in the form of a kilogram of gaseous hydrogen corresponding to the energy content or "value" of 39.4 kWh, the compression effort must be deducted from this value as a provisioning cost. Of the "gross" 39.4 kWh, between 37.7 kWh and 33 kWh remain "net" after the compression step in the supply chain. Figure 92based on data from IRENA, shows the pressure ratios required for the different transport options of gaseous hydrogen and the asso-ciated energy losses (here, however, related to the heating value of hydrogen (33.3 kWh/kg), or *Lower Heating Value (*LHV)).[256] The graph also shows that compression losses are highest when transporting gaseous hydrogen in tanks, e.g. for transport via lorries, while at the same time the transportable quantity is relatively low (density = 40 kg/m^3). This increases the need for transport movements. Transporting gaseous hydrogen in this way is therefore only suitable for short distances and small quantities. If large quantities are to be transported over longer distances, either pipelines or ships are necessary.

2.5.1.1   Transport via pipeline

Currently, there are pipelines with a total length of about 4,600 kilometers (about 2,600 km of them in the USA)[257] for the dedicated transport of hydrogen compared to about 1.2 million

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[256] For an explanation of the difference between higher heating value and lower heating value, see chapter 2.2.2.

[257] In their book, Wernicke et al. discuss, for example, a hydrogen pipeline between Houston, Texas and Baton Rouge. The pipeline network created here connects 20 hydrogen plants over 600 miles (approx. 965 km) (Wernicke et al. (eds., 2014).

kilometers of natural gas pipelines worldwide.[258] There are two options for transporting hydrogen via pipeline: transporting pure (gaseous) hydrogen or blending hydrogen into the existing natural gas pipeline network.

Pipelines designed to deliver 100% hydrogen differ from natural gas pipelines primarily in their material and the compressors required.[259] For a hydrogen pipeline, it must be ensured that the material used is corrosion-resistant to the hydrogen. For this purpose, steel types such as carbon steel or stainless steel are suitable, which, in contrast to other steel types, have a minimum chromium content of 10.5 % in their alloy and are thus corrosion-resistant.[260] The so-called *embrittlement* can lead to cracks (especially at the welding seams) when using non-alloyed steel. However, the use of lower grades of steel means that the pipeline has to be operated at a lower pressure (which reduces the amount of energy transported and thus the economic viability) or the outer wall of the pipelines has to be reinforced to withstand the high operating pressure of 70-100 bar (which increases the CAPEX of the pipeline). [261]

Furthermore, the volumetric energy density of hydrogen, which is 3.1 times lower than that of natural gas, means that the rotors of the compressors used, which ensure that the hydrogen is kept at a constant pressure level over the entire length of the pipeline, have to be operated faster by the same factor in order to transport the same amount of energy.[262] Conversely, this also means that the energy consumption of the compressors is three times higher. Increasing the speed of the rotors is not readily possible but is limited by the strength of the material that must be used for compressors and the corrosion problems with hydrogen that can also occur here.[263] Compressors that can do this are currently in the research phase and could be established on the market in the future as the demand for hydrogen pipelines increases. [264]

2.5.1.2   Costs of pipeline transport

The International Energy Agency (IEA) estimates that the cost of a new hydrogen pipeline (CAPEX) is about 10-50 % higher than that of conventional gas pipelines, due to the increased material costs for the reinforced outer walls and, if necessary, the larger diameter to be able

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[258] Cf. International Energy Agency, 2021Global Energy Monitor, (2022).
[259] Cf. Khan et al., 2021b; International Energy Agency, (2021).
[260] Cf. International Energy Agency, (2021).
[261] Cf. Khan et al., 2021a.
[262] Cf. Khan et al., 2021b.
[263] Cf. Khan et al., 2021b.
[264] Cf. Khan et al., 2021b.

to transport more energy.[265] The following is an example of the boundary conditions for a (new) 1,500 km hydrogen pipeline.[266]

Table 12: Example costs of a new hydrogen pipeline.

Source: Khan et al., (2021).

Length	1500 kilometres
Pressure level	70 bar
Distance between Compressors	500 km
Capacity	4280 t/day
Availability	90 %
CAPEX (total)	USD 4.57 billion
OPEX (total per year)	166.2 million USD (approx. 3.6 %)
Inlet Compression Effort	0.63 kWh/kg H_2
Enroute Compression Effort	0.45 kWh/kg H_2

The authors define the boundary conditions in such a way that the pipeline is operated at 70 bar and compressors have to be installed every 500 km to compensate for pressure losses. The capacity is 4,279 t/d[267] and the investment costs for the pipeline are about ***4.57 billion USD. The*** "inlet compression energy", i.e. the energy that has to be applied to compress the hydrogen from the electrolyser to 70 bar, is 0.63 kWh/kg H_2 and the "enroute compression energy", i.e. the energy that has to be applied along the route to compensate for pressure losses, is 0.45 kWh/kg H_2 **.** In this example, the "transport costs" for the hydrogen amount to a total of 0.69 USD/kg H_2. This price is mainly driven by the high initial and irreversible investment costs for the pipeline.

As a "rule of thumb", the study points out that at a demand of 1 - 1.2 t H_2 /day per kilometre (here approx. 1,500 t/day or 547,500 t/year) economic profitability could be ensured for the transport of hydrogen via new pipelines.[268] Nevertheless, the "sunk costs" for pipeline systems represent an investment risk and presuppose that the demand for hydrogen remains given over the lifetime of the pipeline. In order to reduce the costs for the long-distance transport of large quantities of hydrogen via a pipeline system, two options are available: The re-functioning

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[265] Cf. International Energy Agency, (2021).
[266] Cf. Khan et al., 2021b.
[267] t/d: tonnes per day
[268] Cf. Khan et al., 2021b.

of an existing gas pipeline system, or the blending of hydrogen into existing natural gas pipeline networks.

2.5.1.3   Re-functioning of existing pipeline networks

As mentioned above, natural gas pipeline networks with a total length of 1.2 million kilometers are installed worldwide. The re-functioning is intended to adapt underutilised pipelines or pipelines that will be less utilised in the future due to the potential ramp-up of the hydrogen economy for hydrogen transport. The IEA refers to a report by European Hydrogen Backbone, which puts the costs at 21-33 % of a new hydrogen pipeline.[269] A prerequisite for the re-functioning is that the pipeline material can withstand the risk of embrittlement and the necessary pressure for hydrogen transport. Therefore, costs for reinforcing the outer walls may have to be calculated. In addition, compressors that are not designed for operation with hydrogen (higher impeller speed; embrittlement problems), but also valves, measuring devices, leakage detectors and gas flow control systems have to be replaced.[270] Projects aimed at pipeline conversion have already been successfully carried out. For example, Air Liquide acquired two pipelines in Texas, USA, and converted them to run on hydrogen. Similar projects are planned between Germany and Denmark, for example.

Table 13: Example projects for the conversion of natural gas pipelines for hydrogen transport.

Source: IEA, (2021).

Example project	Region
H_2 HoWi (E.ON)	Holzwickede (NRW) (n.d.) - 2022
MosaHYc (GRTgaz; Creos)	Border triangle (DE, FR, LUX) (70km) - 2022
APA	Western Australia (43km) - 2022

2.5.1.4   Blending into existing natural gas pipeline networks

The blending of hydrogen into natural gas networks is considered to play a transitional role for transport as long as a dedicated hydrogen infrastructure designed for the pure transport of the element has not yet been developed. Hydrogen can be fed into natural gas networks in proportions of between 2 and 10 % before adjustments have to be made to the pipelines, due to the described risk of embrittlement or the continued usability of the equipment used (e.g. compressors).[271] Before hydrogen can be added to the existing gas network, it must therefore first

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[269] Cf. International Energy Agency, (2021).
[270]   Cf. International Energy Agency, 2021Khan et al., 2021b.
[271] Cf. International Energy Agency, (2021).

be ensured that the pipelines used can withstand the desired mixing ratio, which could lead to problems in view of the **heterogeneity of the network.**[272] Furthermore, the lower volumetric energy density of hydrogen compared to natural gas results in an additional challenge for the end consumer: if 10% of the volume of the transported natural gas is exchanged for the same volume in hydrogen, less energy is transported overall (cf. 1 m^3 H_2 with 3.55 kWh vs. 1 m^3 CH_4 with 11 kWh). An industry that wants to improve its CO_2 balance by successively implementing a share of hydrogen and has 10% of the volume of natural gas purchased substituted with hydrogen for this purpose receives less energy to supply its production in this case and must buy gas to cover this accordingly. More must be paid for the same amount of energy (if the supplier charges by volume). Without subsidies or sanctions on CO_2 emissions, such conversions make no economic sense from the consumer's point of view. Finally, it must be ensured that the consumer's machines are designed for the use of natural gas in combination with hydrogen, or the two gases must be separated from each other before use, which in turn means additional energy expenditure.

In summary, the transport of hydrogen via pipeline networks will play a role if large quantities are to be transported over distances of up to 4000 kilometers.[273] Especially in the ramp-up phase of the hydrogen economy, in which the use of low-CO_2 hydrogen in industry is becoming established, the so-called "blending" of 2-10 % hydrogen content into existing natural gas networks can play a role in transporting smaller quantities to the end consumer.[274]

Table 14: Example projects for the admixture of hydrogen in gas grids.

Source: IEA, (2021).

Project name	Status
Avacon + DVGW (Germany)	Pilot project (20 % admixture)
GRHYD (Capelle la Grand, France)	Pilot project (20 % admixture)
Snam (Italy)	Pilot project (10 % admixture)
HyDeploy (UK)	Pilot project (20 % admixture)
Hyp SA (Australia)	Pilot project (5-10 % admixture)

However, as demand grows, dedicated pipeline networks for hydrogen become inevitable, requiring the adaptation of existing natural gas networks (if hydrogen displaces part of the natural gas from the market) or the more costly construction of new hydrogen pipelines. Due to the

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[272] Cf. International Energy Agency, (2021).
[273] Cf. International Renewable Energy Agency, (2022).
[274] Intensive work is being done on the recovery of admixed hydrogen, including a pilot plant by DBI Gas- und Umwelttechnik GmbH, Ontras Gastransport GmbH, and the DVGW. These are all membrane processes, including organic membranes, zeolites and carbon fibres.

high CAPEX of these pipelines, a constant demand must be ensured to stimulate investments. At the same time, however, demand will only increase if hydrogen can be transported cheaply and thus purchased on the market. This "chicken and egg" dilemma (see chapter 2.) can only be compensated by appropriate policy measures.

2.5.2   Storage of gaseous hydrogen in salt caverns

While hydrogen in liquid form could be temporarily stored in cryo-cooled tanks before final consumption thanks to its comparatively high density (see below) or existing infrastructures could be used for derivatives, the question of storage arises for pure gaseous hydrogen. Due to its volatility and low density, even at high compression (40 kg/m^3 at 700 bar), large quantities, such as might be needed for the envisaged German energy transition, cannot be stored in tanks. Too many pressure tanks would simply be needed. The most promising technology is salt cavern storage.
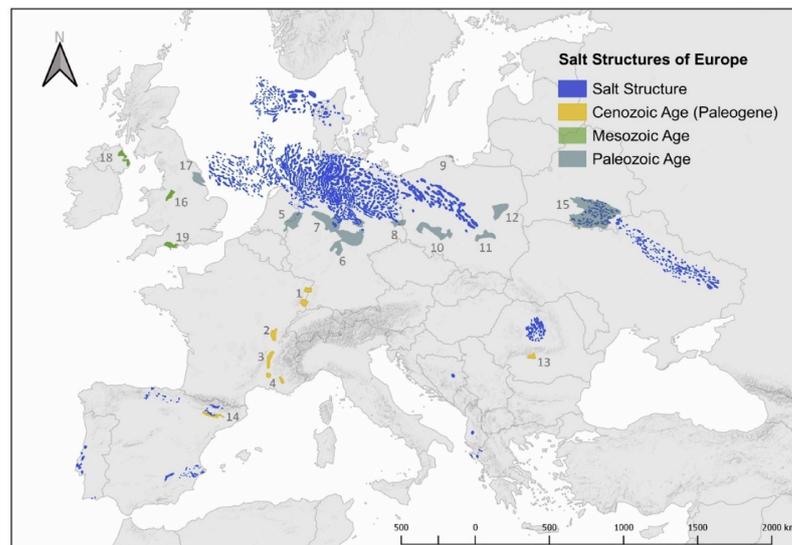
Figure 93: Distribution of salt caverns across Europe.

Source: Caglayan et al., (2020).

Underground storage of natural gas has been established practice for decades. A similar approach can be replicated for the storage of hydrogen in salt caverns, but requires the use of different materials, especially for steel components such as the cavern heads and required pipelines, due to the aforementioned embrittlement problem. [275]

To create a salt cavern, boreholes in a layer of salt rock are filled with water and washed out in the required volume. A significant advantage of salt caverns compared to the use of aquifers or depleted oil and gas fields is the reduced proportion of *buffer gas (*less than 20 %) required.

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[275] Cf. Caglayan et al., (2020).

This buffer is necessary to maintain the pressure (75-200 bar) and thus the stability of the cavern. Furthermore, salt caverns are leak-proof, which prevents losses, and they can be filled and emptied flexibly. [276]

Currently, only four operational hydrogen storage facilities exist in salt caverns, three of which are in the USA and one in the UK.

Table 15: Operational salt cavern projects for hydrogen storage.

Source: IEA, (2021).

Project name	Country	Capacity
Teeside	United Kingdom	27 GWh
Clemens Dome	United States	82 GWh
Moss Bluff	United States	125 GWh
Spindletop	United States	278 GWh

According to the study by Caglayan et al., however, there is immense potential for the expansion of salt caverns in Europe. The authors put this at 84.8 PWh of hydrogen, i.e. 84,800 TWh in total (on- and offshore). As the map in Figure 93 shows, this potential is not evenly distributed across the continent.

Only 9.4 PWh of capacity is allotted to Germany, and here mainly to northern and eastern Germany.[277] HYPOS in eastern Germany, for example, can be named as a pilot project. Here, a salt dome for hydrogen storage is being tested; the location is Bad Lauchstädt (Saxony-Anhalt) of the gas storage operator VNG Gasspeicher GmbH (VGS), along with a pipeline for hydrogen to Leuna.

From the figures for an example project in northern England ("H_2 1"), one can deduce what costs can be expected for comparable projects. Here, a cavern with a volume of 300,000 m^3 and a depth of 1,700 metres is being excavated. The capacity is 1,440 GWh H_2 (equivalent to about 36,548 tonnes (HHV)), the additional *cushion gas* required is 780,000 MWh (about 19796 tonnes (HHV)). CAPEX is 271.25 €/MWh and OPEX is 4 % of CAPEX. In this case, a total investment of €387 million would therefore be incurred.

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[276] Cf. Caglayan et al., (2020).
[277] Cf. Caglayan et al., (2020).

Table 16: Example costs of a salt cavern.

Source: World Hydrogen Leaders, 2022; Massey, (2022).

Volume	300.000 m^3
Capacity	1,440 GWh H$_2$
CAPEX	271.25 €/MWh H$_2$
OPEX	0.10 €/MWh H$_2$
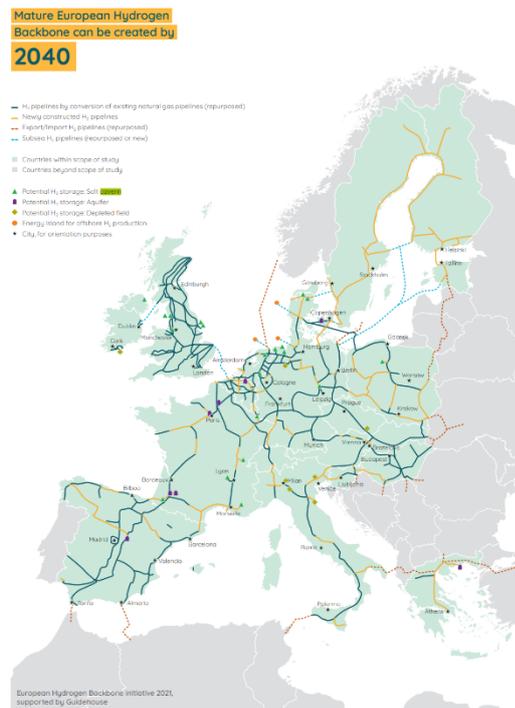
Figure 94: European Hydrogen Backbone project.

Source: Jens et al., (2021).

The expansion of infrastructures and above all supply pipeline networks that are geared to the occurrence of salt caverns will be necessary in order to be able to ensure an inter-European hydrogen supply. Gas for Climate, a consortium of leading gas transport companies in Europe, provides a proposal for what such a network could look like. In this scenario for the year 2040, a total of 53,000 km of hydrogen pipelines are in operation at investment costs of 80-143 billion euros and operating costs of 1.6-3.2 billion euros per year. Of these, 31,800 km are converted gas pipelines and 21,250 km (much more expensive) are newly built pipelines.[278] This should make transport costs of **0.11-0.21 €/kg H$_2$** possible. As can be seen from the map, the network is oriented in such a way that the pipelines connect the producing countries (Morocco, Spain) with the consumers and are directed towards storage facilities such as salt caverns.

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[278] Cf. Jens et al., (2021).

However, the figures mentioned here on salt storage potentials and plans for infrastructure expansion **only refer to Europe**. Similar data must also be created for other continents in order to be able to evaluate the realisation of a global energy transition with hydrogen as energy storage.

2.5.3. Transport

Table 17: Relevant properties of liquid hydrogen for transport.

Density	71 kg/m^3
Temperature	-246 °C (atm)
Volumetric energy density	2.79 kWh/l
Conversion effort	10 kWh/kg H$_2$
Energy Penalty	15-25 % (HHV)

Another way to transport pure hydrogen is through liquefaction (LH$_2$). The advantage of liquid hydrogen over gaseous hydrogen is the increased density. This is 71 kg/m^3 at 2 bar compared to the 40 kg/m^3 of gaseous hydrogen at a pressure of 700 bar. Thus, the volumetric energy density is 2,797.4 kWh/m^3 (2.79 kWh/l). However, condensation occurs at atmospheric pressure of the gas only at very low temperatures (-246.0°C).

To compare this again with methane: Here, condensation at the same pressure already occurs at -161.52°C, which is why less energy is required for the liquefaction of this gas. Data from Linde (2019) and Air Liquide (2020) put the requirement at 10 kWh/ kg H$_2$ (so in terms of the calorific value of 39.4%, a loss of 25%).[279] This figure may vary with varying efficiency of the hydrogen liquefaction plant. The energy input for liquefaction per plant is sensitive to positive economies of scale. Larger plants (50 t/d) use only 9 kWh/kg, while smaller plants (up to 5 t/d) use 11 kWh/kg and are thus more efficient. [280]

The more tons of liquid hydrogen a plant can produce per day, the less energy has to be used per kilogram. In addition, the utilisation factor of the plant determines the energy input, whereby 100 % utilisation means less electricity consumption per kilogram of hydrogen than about 25 %, since, for example, the additional consumption for starting up and shutting down the machines is saved. Large plants with a high utilisation factor are therefore preferable for the liquefaction process. [281]

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[279] Cf. Zemo Partnership, (2021).
[280] By comparison, LNG plants today produce up to 15,000 tonnes per day (Zemo Partnership 2021).
[281] Cf. Zemo Partnership, (2021).

Simplified, the liquefaction process follows four steps, as in the IdealHY pilot project presented by Zemo Partnership: the compression of hydrogen to about 80 bar (0.74 kWh/kg); the "pre-cooling" to about -143°C (0.77 kWh/kg); the "cryo-cooling" to about -246°C (4.85 kWh/kg) and finally the expansion of the hydrogen from 80 bar to 2 bar (0.05 kWh).[282] Obviously, the consumption in this example is "only" 6.41 kWh and thus below the average 10 kWh/kg LH_2 . The authors thus assume that liquefaction can become more efficient through technological progress. Especially the process step of cryo-cooling is very energy-intensive and requires about three quarters of the total process energy.

Overall, the liquefaction of hydrogen is therefore extremely energy-intensive. Depending on the efficiency of the process chain, the *energy penalty* is between 10 and 6 kWh/kg LH_2 and thus 25 % or 15 % (HHV), approximately 3.5 and 2.1 times higher than the expenditure for the compression of gaseous hydrogen (GH_2) (2.5 kWh/kg). When the transport of LH_2 can be economically and energetically worthwhile is considered in the next section. Due to the higher volumetric energy density of liquid hydrogen, two forms of transporting LH_2 are conceivable: Transport by lorry and transport by ship.

2.5.3.1   Transport of liquid hydrogen by truck

A lorry can carry about 4000 kg of liquid hydrogen, whereas with the same volume (approx. 56 m3 or 56,000 litres) only about 1100 kg of gaseous hydrogen can be transported (at 350 bar: 21 kg/m).[3][283] Despite external insulation of the liquid hydrogen tankers, however, heat cannot be prevented from entering the tanks. This leads to a slight evaporation of the hydrogen and the so-called "boil-off" gas is produced in the tank. If this is not removed, the pressure increases, which is why the excess gas is usually discharged from the tank unused. These energy losses, known as "vent-off", account for approx. **0.3-0.6 % of the quantity contained in the tank per day** during hydrogen transport by truck.[284] Of 4,000 kg, 3,880 kg or 3,760 kg of hydrogen remained after one day. This corresponds to a quite significant amount of lost energy of approx. 4,728 kWh or 9,456 kWh (HHV). The transport of LH_2 over longer distances, which can possibly only be covered in several days by lorry, does not make sense from an economic and energetic point of view due to these losses.

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[282] Cf. Zemo Partnership, (2021).
[283] Up to a pressure of approx. 10 bar, hydrogen behaves almost like a so-called "ideal gas". This means that the density is linear to the applied pressure. However, instead of having a density of 31.5 kg/m³at 350 bar, hydrogen has a density of 21 kg/m³ and 40 kg/m³ at 700 bar. A hydrogen tank therefore does not hold twice as much hydrogen at twice the pressure.
[284] Cf. Zemo Partnership, (2021).

2.5.3.2   Transport of liquid hydrogen by ship
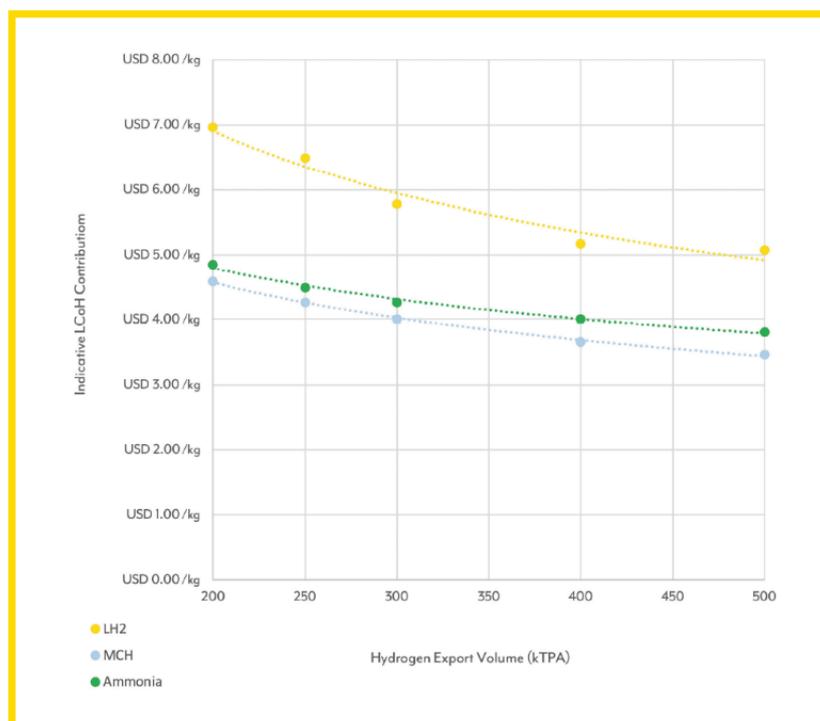
Figure 2.1 - Hydrogen Carrier Supply Chain LCoH Contribution

Figure 95: LCOH trend with increasing export volume.

Source: KBR, (2021).

To transport large quantities of liquid hydrogen over long distances, for example from Chile to Europe, shipping could be an option instead. However, the (port) infrastructure to be provided is significantly more complex than that for transport by truck and therefore means higher CAPEX (see the chapter on transporting H_2 for more detailed information). A study by KBR Advisory Consulting calculated the *levelised costs of hydrogen* (LCOH) for the transport of liquid hydrogen by ship at different export volumes in 2020 (this excludes the production costs for hydrogen but includes the conversion and reconversion costs). The authors found that with increasing export volumes, the LCOH share of transport for liquid hydrogen decreases (positive scale effect), for example because larger export volumes allow standardisation and optimisation of the size of cargo tanks.

With an export volume of 200,000 t/a, the share is therefore 7 USD/kg LH_2, while at 500,000 t/a it falls to 5 USD / kg.[285]

Of the 7 USD, 4 USD are for CAPEX of the infrastructure and 3 USD for OPEX. 51 % of the CAPEX must be spent on the "export terminal", 39 % on the "import terminal" and 11 % on the

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[285] Cf. KBR Advisory Consulting, (2021).

cargo tanks (marine vessels).[286] The high share of the export terminal is due to the high costs for the liquefaction plant.[287] But transport by ship is also affected by boil-off losses. The longer the distance to be covered, the higher the amount of hydrogen lost. This means that in order to transport the same amount, additional hydrogen has to be produced, which has a negative impact on the LCOH. KBR shows in the graph below how the LCOH increase with increasing distance.
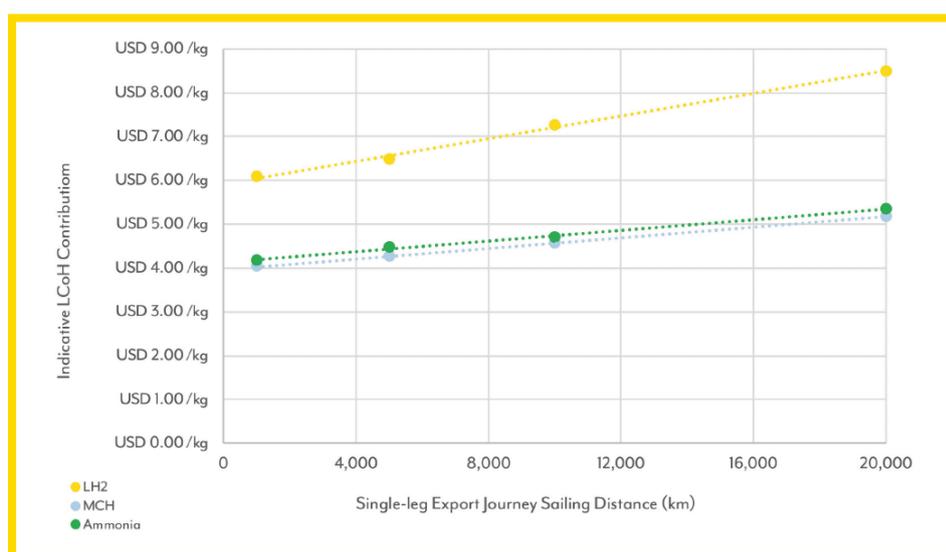
Figure 96: Increasing LCOH with increasing distance due to boil-off losses (250kt/pa).

Source: KBR, 2021

In addition, it must be mentioned that the infrastructure for liquid hydrogen is not yet developed for mass transport. Although 355 t H_2/d are already liquefied daily,[288] there is currently only one ship that can transport liquid hydrogen (HySTRA).[289]

Overall, the transport of liquid hydrogen is mainly affected by the high energy input for its production, the additional energy costs for cooling and the costs for the specific infrastructure. When storing liquid hydrogen, boil-off losses must also be taken into account, which can influence long-term storage. Chemical hydrogen storage (so-called hydrogen derivatives)[290] offer advantages due to their material properties, which make the handling, transport and storage of hydrogen more efficient (the decisive factor here is primarily the "hydrogen storage density" or hydrogen storage capacity).

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[286] Cf. KBR Advisory Consulting, (2021).
[287] Cf. KBR Advisory Consulting, (2021).
[288] Cf. Andersson & Grönkvist, (2019).
[289] Cf. Hein, (2022).
[290] A derivative is a derived substance with a similar structure to a corresponding basic substance ("downstream molecule"). With regard to hydrogen, these are gaseous or liquid energy carriers based on H $_2$.

2.5.4   Chemical hydrogen storage (hydrogen derivatives and LOHC)

In the literature, a distinction is made between two types of chemical hydrogen storage:

- Hydrogen storage systems based on the bonding of hydrogen to hydrogen-lean molecules extracted from the atmosphere. These hydrogen storage tanks release gas mixtures such as CO_2 or N_2 into the atmosphere when they are dehydrogenated. These include ammonia and methanol.

To be more precise, other substances belong to group A, such as formic acid (HCOOH) or methane (CH_4). The former has only a very low gravimetric hydrogen storage capacity of 4.4 % and 53 kg/m^3, which is comparable to compressed, pure gaseous hydrogen (700 bar). This is why this hydrogen storage system is suitable as a transport medium for smaller quantities over short distances and is mainly discussed in connection with hydrogen filling stations.[291] This makes the use of formic acid for the transport of large quantities of hydrogen unlikely. Methane (CH_4), as mentioned above the main component of natural gas, can be produced via the Sabatier process as a reaction of hydrogen and carbon dioxide (CO_2). The substance has a very high gravimetric hydrogen storage capacity of 25 % and 105.6 kg/m^3. As methane is a gas used worldwide, existing infrastructures could also be used for this supply chain, which brings cost advantages. However, the focus of this paper is on hydrogen carriers with the aim of reconversion to hydrogen. Methane would probably be used directly in most cases, which is why little relevant literature can be found on the use case of hydrogen recovery from methane.

- Hydrogen storage systems based on the bonding of hydrogen to hydrogen-lean organic liquids that enable a fully reversible catalytic hydrogenation/dehydrogenation process without releasing other substances into the atmosphere. These include the so-called Liquid Organic Hydrogen Carriers (LOHC).

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[291] Cf. Kawanami et al., (2017).

2.5.4.1   Ammonia as a chemical hydrogen storage

Table 18: Relevant properties of ammonia for hydrogen transport.

Density	0.77 kg/m^3 (1 atm) 690 kg/m^3 (9 bar)
Hydrogen storage capacity	17.7 % (gravimetric); 122 kg/m^3 (volumetric)
Reaction enthalpy	-30.7 kJ/mol (exothermic)
Boiling point	-33°C
Minimum ignition energy	14 mJ
Conversion effort	2-4 kWh/kg H$_2$
Reconversion expenditure	8 kWh/kg H$_2$
Energy Penalty	10 - 12 kWh/kg H$_2$ (25 - 30 % HHV)

Ammonia, a colourless synthesis gas, is the reaction product of nitrogen and hydrogen (NH$_3$). NH$_3$ is one of the most produced chemicals in the world (235 Mt in 2019)[292] and is largely produced using the Haber-Bosch process, which has been known since the early 20th century. Ammonia is in demand worldwide in industry as a basic material for fertilisers and for the production of plastics and synthetic fibres. For more details, see chapter 2.6.

At atmospheric pressure, ammonia has a higher density than hydrogen (0.77 kg/m^3 vs. 0.09 kg ammonia), but a much lower calorific value (4.8 kWh/kg vs. 39.4 kWh/kg). A decisive advantage for ammonia as a hydrogen transport medium lies in its comparatively easy-to-handle physical properties in the liquid state and its high hydrogen storage capacity: the condensation temperature is -33°C, instead of -246°C at atmospheric pressure as is the case with hydrogen. This means that energy can be saved on cooling on the transport route. At a pressure of 9 bar, the gas can be liquefied at 20°C already. The density of ammonia in the liquid state increases to 690 kg/m^3. The gravimetric proportion of hydrogen in ammonia is 17.7 % and the volumetric 123 kg/m^3. *De facto,* therefore, more hydrogen can be transported on one cubic metre with ammonia as hydrogen carrier than in pure liquid form. In addition, the Haber-Bosch process, through which the synthesis gas is produced as described above, involves a comparatively low conversion effort (2 to 4 kWh/kg or 10 % of the HHV). On the other hand, the reconversion of

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[292] Cf. Statista, (2022).

ammonia into hydrogen is energy-intensive (so-called cracking process) and is currently still in the pilot phase, i.e. it is not yet being operated commercially. The expenditure here is estimated at 10-12 kWh/kg hydrogen (approx. 25-30 % of the HHV H_2).[293] The described "energy penalty" in the transport of ammonia is therefore not at the beginning but at the end of the supply chain, unlike in the transport of pure hydrogen.
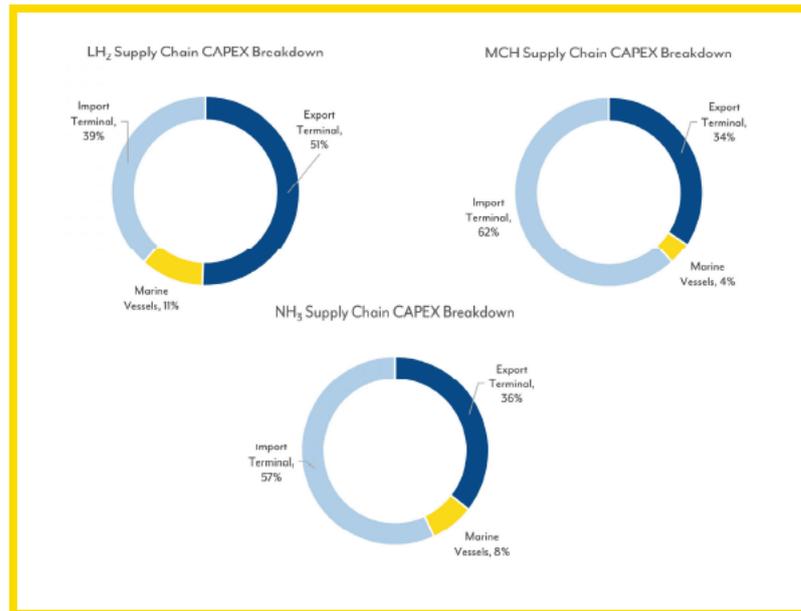
Figure 97: Cost shares along the hydrogen supply chain.

Source: KBR, 2021

This also shows Figure 97 which refers to long-distance transport by ship.

The import terminal accounts for the largest share of capex (57 %), due to the high costs for reconversion plants, while the export terminal only accounts for 36 %.[294] This is due to the fact that plants for the Haber-Bosch process have already been able to reduce their CAPEX by scaling up through many years of implementation in the market. KBR calculates the share of CAPEX in the transport costs for one kilogram of ammonia to be about 3 USD and OPEX to be 1.48 USD.

Again, with increased export volumes, the LCOH for hydrogen transport in the form of ammonia can be reduced by up to 12 % (250,000 t/a = 4.48 USD; 500,000 tons per year <= 4 USD).[295]

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[293] Cf. Andersson & Grönkvist, (2019). The cracking process is the reverse reaction of the ammonia synthesis process. Ammonia starts to decompose at temperatures above 200°C, but temperatures up to 650°C usually have to be applied to achieve complete decomposition of the chemical into its components. Ruthenium, a very expensive precious metal, is also used as a catalyst. To reduce costs and also ensure availability, less rare precious metals are being investigated for use (nickel, cobalt, iron), but this could lead to required temperatures of up to 900°C due to poorer conductivity (cf. Andersson et al. 2019).
[294] Cf. KBR Advisory Consulting, (2021).
[295] Cf. KBR Advisory Consulting, (2021).

It should be noted, however, that the high reconversion costs mean that additional ammonia must be produced in order to provide the net amount of energy transported at the beginning.

If 1,300 t of ammonia are transported daily, about 22.94 t of hydrogen could (theoretically) be produced from this (molar mass H_3 = 3.02 g/mol). This corresponds to an energy quantity of 0.9 GWh (HHV). The production of one kilograms of hydrogen from ammonia costs 8 kWh, i.e. about 0.18 GWh for the quantity mentioned. Of the 0.9 GWh of energy supplied, 0.72 GWh remains, a loss of about 20 %. The energy penalty of 0.18 GWh must be compensated by additional production, which corresponds to about 4.5 t H_2 or 254.7 t ammonia per day. Extrapolated for the year, this results in a necessary additional production of 92,710 t. The resulting additional production costs have a negative impact on the LCOH.

Due to its advantageous properties (relatively low boiling temperature and high proportion of transportable hydrogen) and the well-established production process as well as the infrastructure and necessary technology already available in many places, the transport of ammonia as a carrier of hydrogen over long distances is assessed in the literature as superior to liquid hydrogen.

The graph of the IEA (Figure 98) shows, in simplified form, various scenarios for the production and transport of hydrogen (with the goal of the end use of hydrogen).
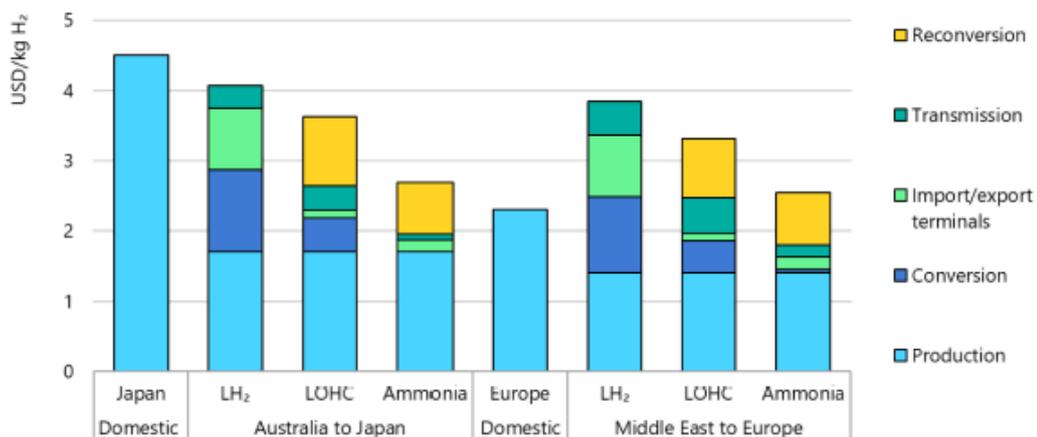
Notes: LH₂ = liquid hydrogen. LOHC = liquid organic hydrogen carrier. Assumes distribution of 1 000 t H₂/d. Storage costs are included in import and export terminal expenses. Hydrogen is produced from electrolysis using renewable electricity.
Source: Based on IAE (2016).

Figure 98: Projected costs for hydrogen transport (incl. production).

Source: IEA, 2021

For the Middle-East to Europe route, it is clear that in this projection ammonia is cheaper than LH₂ as a means of transporting hydrogen, even including reconversion costs. The agency

assumes that the hydrogen is produced from renewables, with a transport volume of 1,000 t/d (or tpd). However, the graph also shows that hydrogen produced and transported in Europe is cheaper than hydrogen imported from the Far East, even if the production costs there are lower.

If liquid ammonia were used directly (for example to generate electricity through combustion in gas turbines or as fuel for shipping) and the reconversion costs were thus saved, the production costs for ammonia imported in this way could be lower (see Figure 98) The cost analysis for the transport of ammonia (or chemical hydrogen carriers in general) thus always focuses on the end use of the consumer.

2.5.4.2   Methanol as a chemical hydrogen storage

Another energy-dense hydrogen derivative is methanol ($CH_3 OH$). The simplest representative of the alcohol group has a gravimetric hydrogen storage capacity of 12.5 % and a volumetric capacity of 99 kg/m^3, comparable to ammonia.

The most widespread methanol production route is via the synthesis of hydrogen and CO_2. This process is technically mature, although less established than the "traditional" natural gas-based production method.[296]

Table 19: Relevant properties of methanol.

Density	792 kg/m^3
Hydrogen storage capacity	12.5 % (gravimetric); 99 kg/m3 (volumetric)
Reaction enthalpy	-239 kJ/mol (exothermic)
Boiling point	64,7 °C
Minimum ignition energy	0.2 mJ
Conversion effort	1.3-1.8 kWh/kg H_2 (4.5 % HHV)
Reconversion expenditure	6.7 kWh/kg H_2 (17 % HHV)
Energy Penalty	21.5 % (HHV)

However, the same catalysts can be used in both processes. In addition, temperatures between 220°C and -280°C and a pressure in the range of 50 - 100 bar are required. This reaction is also exothermic. Andersson et al. calculate an expenditure of 1.3 - 1.8 kWh/kg H_2 for the hydrogenation of CO_2, 4.5 % of the HHV.[297] Further details can be found in chapter 2.6.

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[296] Cf. Andersson & Grönkvist, (2019).
[297] Cf. Andersson & Grönkvist, (2019).

Cost of Methanol manufacturing: **1.87 €/l$_{DE}$** for 300 MW output at 8,000 operating hours → 434 kt/a
Main economic assumptions: 4.6 €/kg$_{H2}$, 70 €/t$_{CO2}$, 32 €/t$_{steam}$, 97.6 €/MWh$_{electricity}$, Lifetime= 20 a, interest rate= 8%
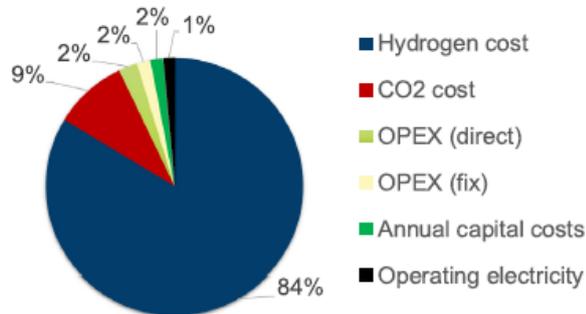
Figure 99: Cost shares in the production of methanol; Source: Schorn et al. 2021

There are three ways of reconverting methanol into hydrogen and CO_2:

1. The steam reform process,

2. the partial oxidation with oxygen or

3. methanol thermolysis. [298]

As with ammonia, these reconversion processes are endothermic, i.e. a higher energy input is necessary than for synthesis. Here, the authors calculate 6.7 kWh/kg H_2 in the form of heat, i.e. 17 % of the HHV.[299]

In a paper from 2021, Schorn et al. looked at the transport costs of renewable methanol as a hydrogen carrier.[300] The authors show that in the production costs of methanol, the costs for the hydrogen to be produced via electrolysis (84 %) and the production costs for the CO_2 (9 %) account for the largest share.

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[298] Cf. Andersson & Grönkvist, (2019).
[299] Cf. Andersson & Grönkvist, (2019).
[300] Cf. Schorn et al., (2021).

Table 2

Methanol production costs in €/t as a function of the CO_2 price and H_2 net production costs. The numbers given are valid for the system size of 300 MW and the presented methodology. Current (fossil, year: 2018) methanol market price: 400 €/t [65]. The timeline for the hydrogen production costs is from IRENA [7].

CO₂ Price [€/t]	time	NPC H₂ [€/kg] 2050	2030						2020
		1	1.5	2	2.5	3	3.5	4	4.5
biomass	0	254	350	445	578	635	731	826	921
	20	282	377	473	606	663	758	854	949
	40	310	405	500	634	691	786	881	977
industry	60	337	433	528	661	719	814	909	1004
	80	365	461	556	689	746	842	937	1032
	100	393	488	584	717	774	869	965	1060
	150	462	558	653	786	843	939	1034	1129
DAC	200	532	627	722	856	913	1008	1103	1199
	300	670	766	861	994	1051	1147	1242	1337
	400	809	904	1000	1133	1190	1285	1381	1476
	500	948	1043	1138	1272	1329	1424	1519	1615
	800	1364	1459	1554	1688	1745	1840	1936	2031

NPC range	MeOH production…	
<600 €/t	**Competitive**	→ Max. 150% of current price level
>600 < 1200 €/t	**Possibly competitive**	→ Max. 300% of current price level
>1200 €/t	**Not competitive**	→ More than 300% of current price level

Figure 100: Sensitivity analysis of methanol production costs.

Source: Schorn et al., 2021

Should the production costs for renewable methanol be reduced to become cost-competitive with conventional methanol (price level of 400 €/t in 2018), it must be ensured that hydrogen and CO_2 can be purchased at the lowest possible price. In concrete terms, Schorn et al. carry out a sensitivity analysis (see Figure 100) and define renewably produced methanol as competitive if it can be produced in a range of < 600 €/t (because it is to be expected that fossil produced methanol will become more expensive rather than cheaper, due to the sanctions related to the CO_2 emissions caused). One result is that methanol could be produced at a price of 578 €/t if (renewable) hydrogen is free for 2.5 €/kg and CO_2 (e.g. sourced from biomass).[301] Provided a cost improvement in the bottlenecks for hydrogen produced by electrolysis (i.e. price drop of electrolyser CAPEX to 400 €/kW, renewable electricity costs of 20 €/MWH and a

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[301] Cf. Schorn et al., (2021).

utilisation factor >50 %) can be achieved, methanol could be produced in certain regions of the world at a competitive price from 2030 onwards.

Since methanol is already traded worldwide on the basis of fossil raw materials, existing infra-structure can be used to transport it (as is the case with ammonia). Regular crude oil transport ships are suitable for this. This saves costs for the reconstruction or new construction of import and export terminals and other necessary equipment. Schorn et al. calculate on the basis of the calculations of Pfennig et al.[302] with 5 €/t for a distance of 10,000 kilometers.[303] As the distance increases, the transport costs per ton of methanol also increase linearly. This results in the following graphical representation in Figure 101:
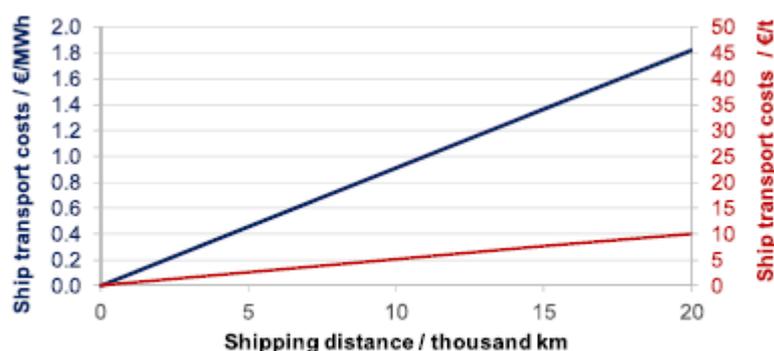
Fig. 10. Methanol transportation costs based on Pfennig et al. [63] as a function of the shipping distance.

Figure 101: Transport costs of methanol per MWh or tonne by distance.

Source: Pfennig et al., 2017

In a next step, the authors calculate the import costs of methanol in 2030 for potential trade routes and compare them to the costs of liquid transported hydrogen, e.g. from Jeddah, Saudi Arabia to Hamburg. The results show, and the above comments on liquid hydrogen confirm this, that its transport costs are much higher than those of methanol (11.25 - 14.17 €/GJ vs. 0.20 - 0.34 €/GJ). On the other hand, the production costs for methanol are higher, depending on the price of CO_2 (as the production costs for hydrogen are the same in this scenario). For costs of 30 - 80 €/t CO_2 methanol is cheaper or equally cheap to liquid hydrogen. From a CO_2 price of 100 €, methanol is more expensive. Both energy carriers could therefore be imported to Germany for 1 €/l in 2030 (at a CO_2 price of 80 €/t for methanol). If CO_2 is available for less than 80 €, the import costs for methanol are cheaper than those for liquid hydrogen. One litre of fossil-produced diesel cost 0.59 € in 2019.

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[302] Cf. Pfennig et al., (2017).
[303] Cf. Schorn et al., (2021).
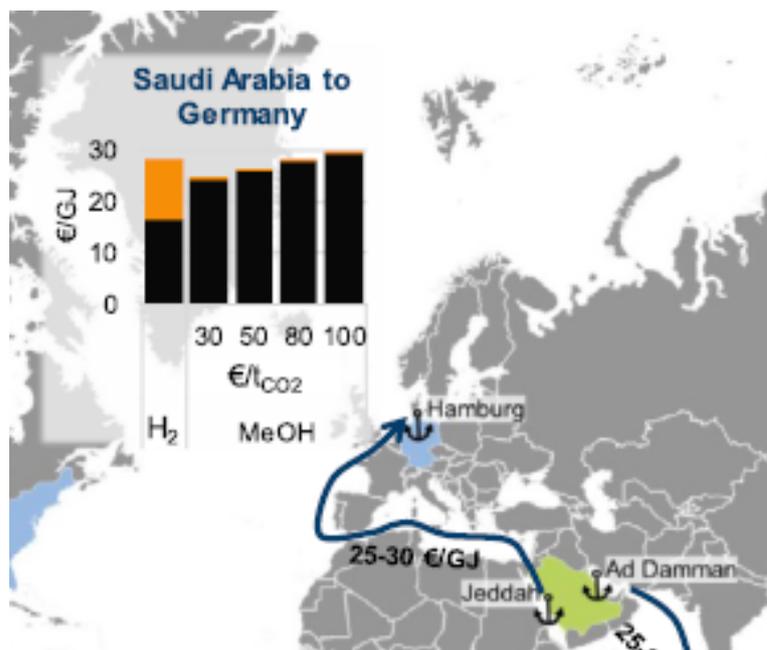
Figure 102: Costs for transport route Saudi Arabia-Germany.

Source: Schorn et al., 2021

Even in this scenario, which includes price reductions in the production of hydrogen-based energy sources, there is still a significant price difference compared to fossil fuels, as long as no sanctions or subsidies are introduced for renewables, or production and transport costs can be reduced even further.

It should also be noted that the cost calculation by Schorn et al. does not include the costs for the reconversion of methanol into hydrogen, should the desired end product be hydrogen. The authors argue that the application field of the chemical is broad (especially as a marine fuel), so that the substance could also be used directly instead of reconverting it at high additional costs (cf. energy penalty of 17 % / kg H_2).[304] Another additional aspect of the use of methanol as a hydrogen carrier is the origin of the CO_2 used. Methanol can only be climate-neutral if its production (and possibly direct use) does not release any additional CO_2 into the atmosphere. Here, as presented by Schorn et al., CO_2 could be used for synthesis with hydrogen, which was captured in industry, then transported to Europe, for example, and reused after splitting off hydrogen (CO_2 cycle). Another possibility is the use of CO_2 from direct air capture, which is, however, currently still very expensive (see chapter on CCS). An important aspect in this regard is the certification of hydrogen and its derivatives, which is taken up below.

In summary, methanol has the advantage over liquid hydrogen and ammonia that it can be transported without the need for cooling and that costs can be saved due to the existing

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[304] In contrast to the "cracking process" for ammonia, the splitting of methanol back into hydrogen is technically established and is used in the production of hydrogen in small quantities and for metal treatment.

infrastructure. However, methanol has a lower hydrogen storage capacity than ammonia in particular, which affects the economic viability of this transport medium if the goal is to recover the hydrogen itself. In addition, there is the problem of ensuring CO_2 neutrality. As a hydrogen carrier for transport, ammonia is therefore favoured in many studies on the topic.

Safety aspects in the transport of hydrogen, ammonia and methanol

When transporting liquid hydrogen, ammonia and methanol, safety-relevant aspects must be taken into account. Hydrogen is not toxic but highly flammable (minimum ignition energy of only 0.019 mJ). Ammonia and methanol are highly toxic substances and can lead to environmental pollution in the event of leakage. Since the latter are internationally traded commodities, corresponding health and safety standards already exist. For hydrogen, such standards have yet to be created.

2.5.4.3   Liquid Organic Hydrogen Carriers (LOHC)

LOHC serve as carriers for hydrogen and are produced by the hydrogenation (or loading) of a LOHC molecule (H_0 LOHC) and subsequently dehydrogenated (discharged) to use the hydrogen.[305] In its dehydrogenated form, the LOHC as hydrogen storage is in a liquid aggregate state (unlike, for example, nitrogen in the case of ammonia or CO_2 in the case of methanol). This has the advantage that the LOHC can be pumped to the hydrogenation reactor instead of requiring an additional compression effort as is the case, for example, with the synthesis of N_2 and H_2.[306] Like the Haber-Bosch process, the hydrogenation process is exothermic. Thus, significant energy savings can be achieved during hydrogenation and LOHCs have the lowest conversion effort among chemical hydrides (0.7 kWh_{el} /kg H_2).[307]

The hydrogenation process uses compressed hydrogen in a pressure range between 10 and 50 bar at a temperature between 130 and 200°C.[308] Among the best studied and most economically viable LOHCs are toluene-methylcyclohexane (T-MCH, see table below) and dibenzyltoluene (DBT, see Table 21). The gravimetric hydrogen storage capacity for the former is 6.1 % and the volumetric is 47 kg/m^3. For dibenzyltoluene these values are 6.2 % and 64 kg/m^3.

Again for comparison: 122 kg of hydrogen can be transported per cubic metre with ammonia as the carrier medium, i.e. approx. 2.6 or 1.9 times as much. While the hydrogenation process of LOHCs consumes little energy relative to ammonia, the dehydrogenation process

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[305] Cf. Niermann et al., (2019).
[306] Cf. Andersson & Grönkvist, (2019).
[307] Cf. Andersson & Grönkvist, (2019).
[308] Cf. Andersson & Grönkvist, (2019).

(endothermic) is more energy-intensive. For T-MCH, temperatures up to 350°C and an energy input of approx. 11.2 kWh/kg H_2 are required, for DBT 270-290°C and 9 kWh/kg H_2 (in the form of heat).[309]

Table 20: Important properties for the transport of hydrogen via T-MCH.

Density	770 kg/m³
Hydrogen storage capacity	6.1 % (gravimetric); 47 kg/m³ (volumetric)
Conversion effort	0.7 kWh/kg H_2 (electricity)
Reconversion expenditure	11.2 kWh/kg H_2 (heat)
Energy Penalty	30 % (HHV)

Table 21: Important properties for the transport of hydrogen via DBT.

Density	1032 kg/m³
Hydrogen storage capacity	6.2 % (gravimetric); 64 kg/m³ (volumetric)
Conversion effort	0.7 kWh/kg H_2 (electricity)
Reconversion expenditure	9.0 kWh/kg H_2 (heat)
Energy Penalty	24.6 % (HHV)
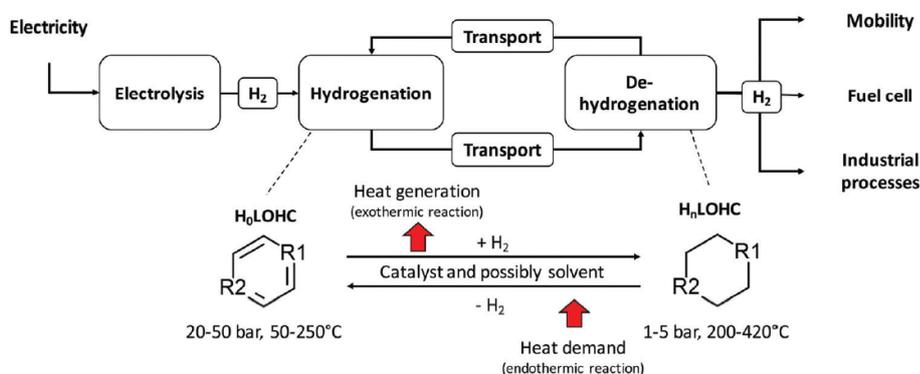
Figure 103: Concept LOHC.

Source: Niermann et al., 2019 .

LOHCs such as T-MCH and DBT offer several advantages for the transport of hydrogen. Firstly, they are liquid at room temperature and have similar properties to crude oil-based energy carriers such as petrol or diesel. Theoretically, it is therefore possible to use existing infrastructures such as pipelines, ship transport or rail transport for the transport of hydrogen via LOHCs and thus save costs.[310] In addition, there is no need to produce, collect and store other gases besides hydrogen in an energy-intensive way, as is the case with ammonia.[311] Another

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[309] Cf. Niermann et al., (2019).
[310] Cf. Niermann et al., (2019).
[311] Cf. Andersson & Grönkvist, (2019).

advantage of LOHCs is their resistance to boil-off losses, which are a particular burden on the transport of pure hydrogen in liquid form. LOHCs could therefore potentially be suitable carriers for the long-term storage of hydrogen.[312] Finally, the reversibility of the substances means that the LOHCs could be shipped back to the site of hydrogen production after dehydrogenation, hydrogenated and thus reused. Theoretically, a circular economic model can thus be created. In practice, however, it turns out that LOHCs must deteriorate and be exchanged during storage and transport due to side reactions.[313] This creates additional waste.

Another disadvantage is derived from the material properties: DBT in particular has a much higher density than ammonia. At the same time, the amount of hydrogen that can be transported is lower ($47 \ kg/m^3$ or $67 \ kg/m^3$ vs. $122 \ kg/m^3$). Simplified, this means that a larger volume is needed for the same amount of transported hydrogen and thus additional costs may be incurred for e.g. additional tanks (e.g. ship or rail transport). In addition, this higher volume then transported has a higher weight, which increases the fuel consumption of the respective means of transport, for example. Although this chapter focuses on transport with the aim of using the hydrogen, it should still be mentioned here that LOHCs, in contrast to ammonia for example, must be reconverted and cannot be used directly. The listed reconversion effort (which is also higher than for ammonia) is therefore indispensable to obtain the hydrogen and therefore has a negative impact on the LCOH. As mentioned above, it could be considered for ammonia to use the chemical directly, save the reconversion effort and thus reduce the costs. Such a business model is being tested between Japan and Australia, for example.[314]

In their study, Niemann et al. analyse the costs of a LOHC-based hydrogen supply chain. A first interesting result of this study are the raw material prices for different LOHCs:

Table 22: Raw material prices for LOHC.

Source: Niermann et al., (2019).

Substance	Price [€ per kilogram]
N-ethylcarbazole	40,00
Dibenzyltoluene	**4,00**
1,2-dihydro-1,2-azaborine	100,00
Napthalene	0,60
T-MCH	**0,80**

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[312] Cf. Niermann et al., (2019).
[313] Cf. Niermann et al., (2019).
[314] Cf. Hughes & Beck, (2022).

T-MCH and naphtalene are significantly cheaper than dibenzyltoluenes, while the other LOHCs listed are likely to be uneconomical for transport due to their raw material costs alone. Across the entire supply chain, Niermann et al. simulate the following costs per year (a distance of 5,000 km and transport by ship were assumed, costs in 1,000 €/a):

Table 23: Costs LOHC over entire supply chain in 1,000 €/a.

Source: Niermann et al., (2019).

	Storage	Conversion	Reconversion	Production	Consumption	Transport	Auxiliary units	Total
DBT	25.048	1.310	4.279	75.786	38.963	4.351	28	149.765
NAP	14.620	1.757	24.626	78.691	38.963	4.725	29	163.411
T-MCH	12.610	796	23.722	78.938	38.963	4.351	25	159.405

DBT and T-MCH are thus cheaper than naphtalene. It is interesting that DBT achieves a lower overall price despite the higher raw material costs. This is due to the lower reconversion costs. From an economic perspective, DBT and toluene or T-MCH are the cheapest LOHCs according to this study, due to comparatively low raw material costs. In this scenario, the total costs (from production to consumption) are € 13.60/kg H_2 and € 14.50/kg H_2 for T-MCH.
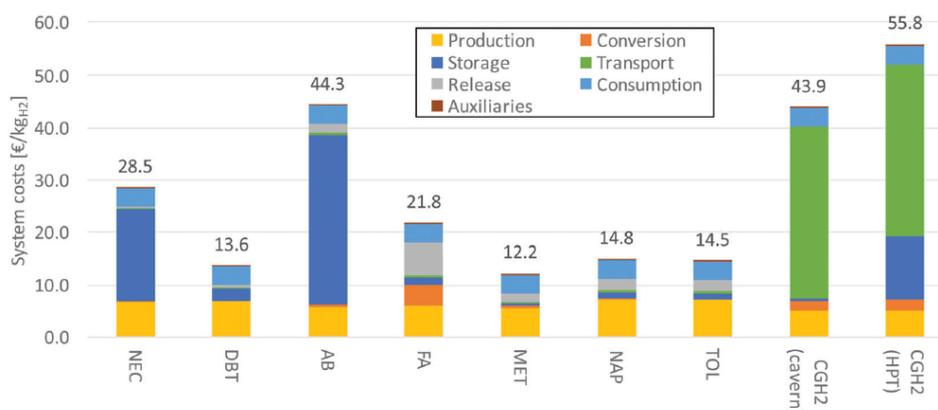
Fig. 10   System costs with internal covering of the dehydrogenation heating (NEC: *N*-ethylcarbazole, DBT: dibenzyltoluene, AB: 1,2-dihydro-1,2-azaborine, FA: formic acid, MET: methanol, NAP: naphthalene, TOL: toluene, CGH₂: compressed hydrogen gas, HPT: high-pressure tank).

Figure 104: System costs LOHC.

Source: Niermann et al., (2019)

The high system costs for gaseous hydrogen, which is subsequently stored in caverns or in hydrogen tanks, are striking. Due to its volatility, the transport of gaseous hydrogen (even in a compressed state) by ship is not economically viable. The authors have therefore assumed transport via a newly built pipeline. As a result, the initial investment costs (CAPEX) are much higher than LOHCs, which can be transported and temporarily stored using an already existing infrastructure from oil trading.

According to the authors, the reconversion costs for LOHCs could be further reduced if existing process heat can be used for the dehydrogenation process. For example, a plant is conceivable in which electricity is to be generated from the hydrogen obtained, and LOHC is stored for this purpose. For this, a fuel cell is needed, which, to put it simply, reverses the process of electrolysis. If a high-temperature fuel cell is used (see section 2.4.3 High-temperature electrolysis (HTEL) for an explanation of the principle), the process heat generated during the combustion of hydrogen could be used to generate electricity for the dehydrogenation of the LOHCs. The diagram below in Figure 105 shows the potential savings:
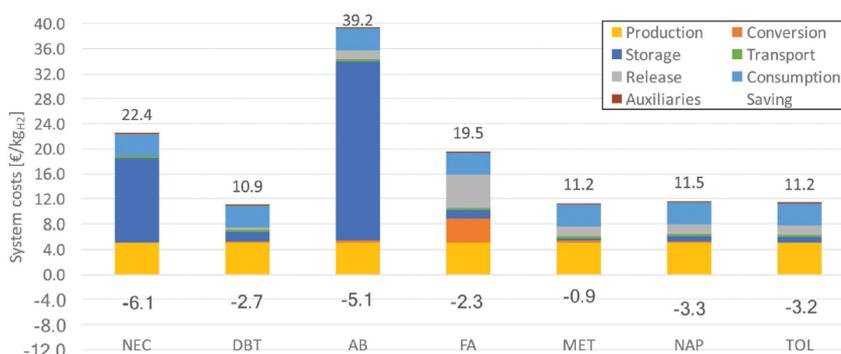
Fig. 12   System costs with covering of the dehydrogenation heating with waste heat of fuel cells (NEC: *N*-ethylcarbazole, DBT: dibenzyltoluene, AB: 1,2-dihydro-1,2-azaborine, FA: formic acid, MET: methanol, NAP: naphthalene, TOL: toluene).

Figure 105: System costs LOHC with use of surplus heat

Source: Niermann et al., (2019).

In summary, the transport of hydrogen via T-MCH and DBT is considered technologically mature and ready for use in the market.[315] It should be emphasised, however, that LOHCs are not yet traded internationally and have so far only been tested on a pilot scale.

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[315] Cf. Niermann et al., (2019).

2.5.5   Summary evaluation of the transport options
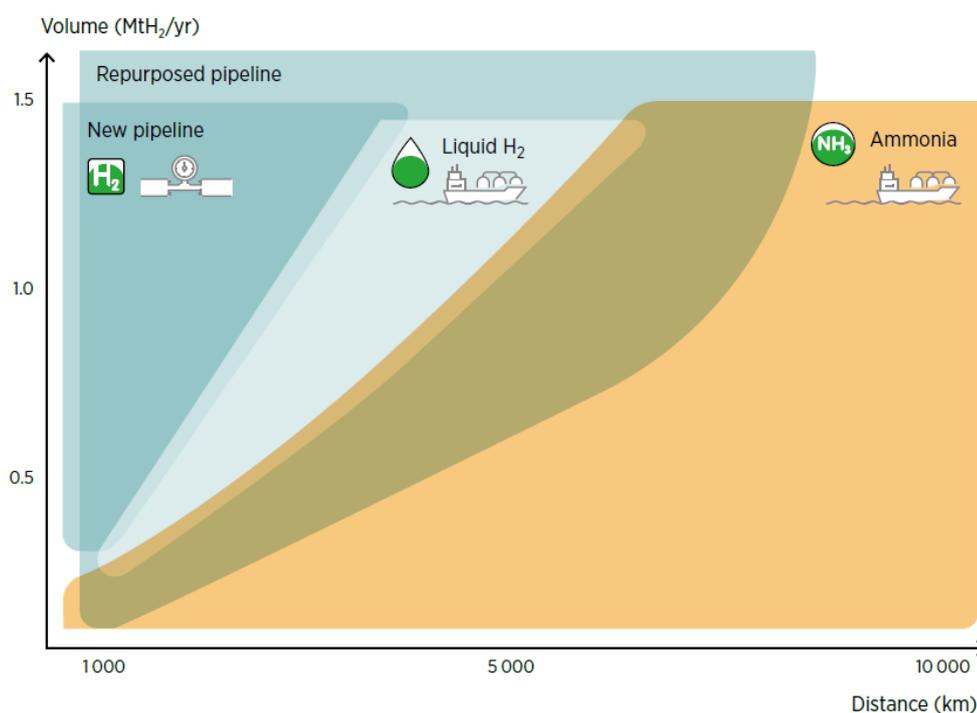
Figure 106: Cost efficiency of hydrogen transport by distance and quantity. Source: IRENA, (2022).

The demand for hydrogen derivatives will depend on the projected costs, which are calculated differently depending on the source and the boundary conditions used. While the IEA assesses, for example, ammonia (also with reconversion) more favourably than LOHC (see Figure 106), the Hydrogen Council sees LOHCs at an advantage, unless the ammonia is used directly. The decisive factors are always the cost assumptions for infrastructure to be provided as well as conversion/ reconversion efforts and the underlying energy costs. Therefore, a final assessment of which hydrogen derivative is the "better" one can only be made on the basis of a concrete case. The advantages and disadvantages of the various hydrogen transport forms are summarised once again on the first page of this report. Through the analysis, trends for the transport of hydrogen can be identified depending on the distance, based on the adjacent assessment by IRENA (2022):

- *Transport over medium distances (1000 - 4000 km)*

   The graph in Figure 106 shows that the gaseous transport of hydrogen is more economical than other forms of transport, even with newly built pipelines and a corresponding transport volume per year. A breakdown of the calculation path cannot be found in the respective IRENA report, but it can be assumed that the relatively low energy penalty and the high transport volume can compensate for the high CAPEX up to this distance. For distances above 4000 km, the construction of new pipelines is uneconomical

compared to other forms of transport (the longer the pipeline, the higher the investment and operating costs).

- *Transport over long distances (>4000 km)*

  However, the graph also shows that converted natural gas pipelines for hydrogen significantly increase the potential transport distance for gaseous hydrogen because the investment costs can be reduced (see above). If no pipeline network is available or the distance cannot be bridged by pipelines, transport by ship is an option. For transport by ship, hydrogen should be available in liquid (pure) form or as a liquid hydrogen derivative due to its higher density, so that larger quantities of hydrogen can be transported given the limited ship capacity. If hydrogen is to be consumed as an end product, the transport of liquid hydrogen can be economically viable due to the omitted reconversion costs. However, the boil-off losses to be taken into account (which increase over longer distances) and the high initial conversion costs limit the possible business cases and it must be shown on the basis of concrete case studies to what extent liquid hydrogen transport can economically hold its own against hydrogen derivatives, especially ammonia. The latter, in turn, is favoured by IRENA for long distances. This can be explained by the already well-developed infrastructure (resulting in a reduction of CAPEX) and the de facto higher hydrogen storage density per cubic metre than LH_2 or methanol (71 kg/m^3 vs. 122 kg/m^3). If the ammonia is used directly (depending on the buyer's requirements and equipment), the costs are further reduced by the elimination of reconversion costs.

Finally shows Figure 106 also shows that gaseous hydrogen from Europe (e.g. Spain) via pipeline could be cheaper in the future compared to imported hydrogen from distant destinations. Projects such as the European Hydrogen Backbone therefore aim to make the pipeline infrastructure within Europe "hydrogen ready", with shares of new pipelines and the conversion of existing gas pipelines to reduce CAPEX.[316] This may have an impact on the aspirations of some emerging and developing countries to become hydrogen exporters in the future due to their geographical location. If the large sales markets in the industrialised countries can cover their demand even with hydrogen that is cheaper on balance, it will be difficult for these countries to earn money here. In addition, planned certifications for "green" hydrogen such as the RED III directive and the EU's Carbon Border Adjustment Mechanism (CBAM) could make hydrogen from outside Europe even more expensive. The transport of hydrogen from outside Europe can only compete with hydrogen from within Europe if production costs continue to fall and transport and logistics become cheaper at the same time. According to IRENA, this

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[316] Cf. Jens et al., (2021).

requires further technology transfer to economically weaker potential export countries as well as the massive promotion of infrastructure projects (see chapter 2.6), the training of local workers and access to financing sources. [317]

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[317] Cf. International Renewable Energy Agency, (2022).