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Hydrogen and decarbonisation of gas: false dawn or silver bullet?

1. Introduction

This Insight continues the OIES series considering the future of gas. Jonathan Stern has published several high level papers[1] detailing the challenges which fossil-derived natural gas will face as the world starts to turn its back on all fossil fuels. The clear message from these papers is that on the (increasingly certain) assumption that governments in major European gas markets remain committed to decarbonisation targets, the existing natural gas industry is under threat and it is important to develop a decarbonisation narrative leading to a low- or zero-carbon gas implementation plan.

Previous papers have considered potential pathways for gas to decarbonise, specifically considering biogas and biomethane,[2] and power-to-gas (electrolysis[3]). This paper goes on to consider the potential for production, transport and use of hydrogen in the decarbonising energy system. Since the term 'hydrogen economy' was first used in 1970,[4] there have been a number of 'false dawns' with bold claims for the speed of transition to hydrogen.[5] This paper will show that this time, for some applications at least, there are some grounds for optimism about a future role for decarbonised hydrogen, but the lesson from history is that bold claims need to be examined carefully and treated with some caution. Previous papers predominately focused on Europe, which has been leading the way in decarbonisation. Hydrogen is now being considered more widely in various countries around the world, so this paper reflects that wider geographical coverage.

This Insight first considers the potential markets for renewable hydrogen (Section 2) starting with the quite extensive use of (non-renewable) hydrogen in various industries today, and how that industrial use could decarbonise. It then goes on to consider the transport market, for road, rail, sea and air

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[1] See Stern, J. (2017a): https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/01/The-Future-of-Gas-in-Decarbonising-European-Energy-Markets-the-need-for-a-new-approach-NG-116.pdf. Stern, J. (2017b) https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/12/Challenges-to-the-Future-of-Gas-unburnable-or-unaffordable-NG-125.pdf. Stern, J. (2019): https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/02/Narratives-for-Natural-Gas-in-a-Decarbonisinf-European-Energy-Market-NG141.pdf

[2] Lambert, M. (2017): https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/06/Biogas-A-significant-contribution-to-decarbonising-gas-markets.pdf

[3] Lambert, M. (2018): https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/10/Power-to-Gas-Linking-Electricity-and-Gas-in-a-Decarbonising-World-Insight-39.pdf

[4] The Hydrogen Economy at https://courses.lumenlearning.com/introchem/chapter/the-hydrogen-economy/

[5] For example, in 1997, Daimler Benz invested in Ballard, a fuel cell technology company, stating that the company would produce 100,000 fuel cell engines annually by 2005 https://www.wired.com/1997/10/hydrogen-3/. In fact, by 2017 there were fewer than 10,000 fuel cell vehicles globally.

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applications. Finally it considers the potential use of hydrogen for space heating, be it in industrial, commercial or residential buildings.

Having considered markets, the Insight builds on previous OIES papers, by reviewing and comparing the potential routes for production of renewable hydrogen (Section 3), focusing in particular on (a) reforming of methane with Carbon Capture Usage and Storage (CCUS) and (b) electrolysis of water using renewable electricity. Mention is also made of emerging technologies for production of low-carbon hydrogen, including methane pyrolysis.

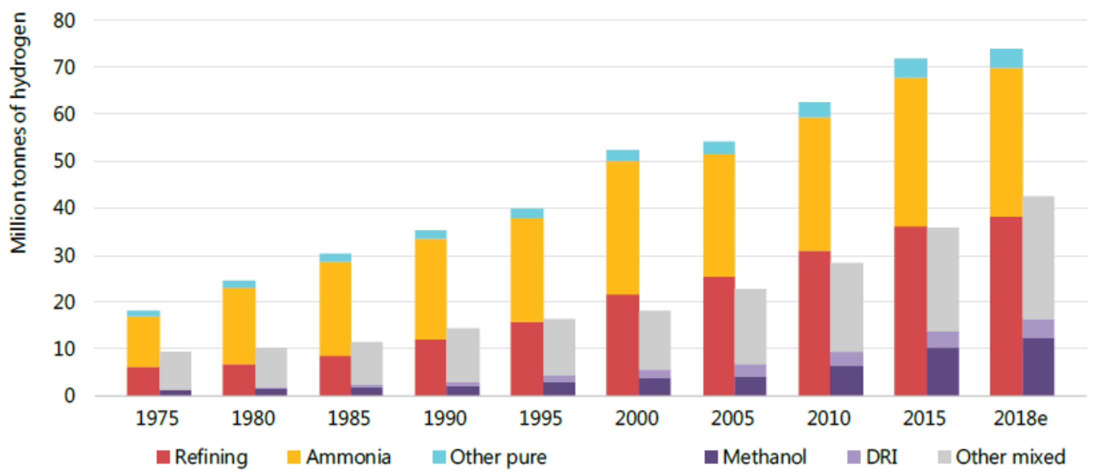
Section 4 then considers options for transport of hydrogen, potentially over long distances, from the point of production to its potential markets. In particular, it reviews the opportunity and challenges to convert existing (predominantly methane) natural gas infrastructure to use for hydrogen, and finds that this is likely to be more challenging than may, at first, appear.

In the discussion and conclusions (Section 5), the paper aims to make a balanced assessment of the potential for hydrogen to play a role in decarbonisation of the energy system, and how its role can fit with alternative pathways, including greater use of electricity and renewable methane.

2. Potential markets for renewable hydrogen

Hydrogen has been widely used in industrial applications for many years. While that usage has been supplied from non-renewable sources, it has provided valuable experience of transporting, handling and use of the product. Around 70 million tonnes per year of pure hydrogen (around 2750 TWh energy equivalent) is currently (2018) consumed globally.[6]

Figure 1: Global annual demand for hydrogen



Notes: DRI = direct reduced iron steel production. Refining, ammonia and "other pure" represent demand for specific applications that require hydrogen with only small levels of additives or contaminants tolerated. Methanol, DRI and "other mixed" represent demand for applications that use hydrogen as part of a mixture of gases, such as synthesis gas, for fuel or feedstock.

Source: IEA (2019), p18

As can be seen from Figure 1, pure hydrogen demand has grown from around 25 million tonnes in 1980, an annual average growth rate around 2.5 per cent per year. Since nearly all of today's hydrogen production is from fossil fuels, it accounts for around six per cent of global natural gas usage and two per cent of global coal usage, estimated to be responsible for around 830 million tonnes per year of annual CO_2 emissions.[7] As context, this level of annual emissions is slightly higher than the total annual

[6] IEA, The Future of Hydrogen (2019): https://www.iea.org/reports/the-future-of-hydrogen
[7] https://www.iea.org/fuels-and-technologies/hydrogen

CO_2 emissions from all sources in Germany (796 million tonnes) and more than double the corresponding figure for the UK (379 million tonnes).[8] Total global energy related CO_2 emissions are estimated to be around 33,000 million tonnes per year.

While this current hydrogen production provides valuable experience, it is clearly not yet relevant to the objective of decarbonisation. The interest in hydrogen in the context of decarbonisation stems from the fact that, at the point of use, it has near-zero emissions, and it has the potential to be produced via a range of low-carbon or zero-carbon pathways.

2.1 Future use of decarbonised hydrogen in industrial applications

Probably the 'lowest hanging fruit' for large-scale use of hydrogen in decarbonisation is by converting existing industrial uses to lower carbon sources of hydrogen. Since hydrogen is already used in these industries, there would be few, if any, technical barriers, and decarbonisation would merely require switching to a low- or zero-carbon method of hydrogen production. As will be discussed further in Section 3, production of low- or zero-carbon hydrogen will, with current technology, be higher cost than current high-carbon hydrogen, so the main challenges to conversion will be economic and regulatory, requiring clear policy-driven actions.

As shown in Figure 1, nearly 40 million tonnes of annual H_2 demand is in the refining sector. Demand in this sector has nearly doubled since 2000, with increasing oil demand and increasing use of hydrotreating and hydrocracking for upgrading of refined products.[9] Future demand for hydrogen in the refining sector will depend on wider decarbonisation policies and the actual evolution of oil demand. The IEA forecasts total refining demand for hydrogen either to be stable around 40 million tonnes per year (in line with current trends), or to decline slowly to a little over 30 million tonnes (to be consistent with Paris agreements) by 2030.[10]

The other significant current use of pure hydrogen is in ammonia production. As shown in Figure 1, over 31 million tonnes per year of hydrogen is currently used for manufacture of ammonia (NH_3). Ammonia is mainly used in production of nitrogen fertilisers (53 per cent of which is urea), demand for which is forecast to continue growing at around one per cent per year.[11] Consideration is also being given to the potential use of 'carbon-free' ammonia as a marine fuel, although this is still at a relatively early stage (see Transport section below).[12]

An additional potentially large scale industrial use of hydrogen in the decarbonising energy system is in iron and steel production. On average, in 2018, 1.85 tonnes of CO_2 were emitted for every tonne of steel produced,[13] while global steel production increased by 3.4 per cent in 2019 to a total of 1,870 million tonnes,[14] which would equate to around three gigatonnes (Gt) CO_2 (or around 10 per cent of total global energy related emissions). 90 per cent of primary steel production today is by the blast furnace/basic oxygen furnace route, using coal as a feedstock.[15] On the other hand, seven percent of primary steel production is by the direct reduction of iron-electric arc furnace (DRI-EAF) route, using

[8] https://edgar.jrc.ec.europa.eu/overview.php?v=booklet2018&dst=CO2pc
[9] IEA (2019), p 94
[10] IEA (2019) p.95
[11] International Fertiliser Association (2018): https://www.yara.com/siteassets/investors/057-reports-and-presentations/other/2018/fertilizer-industry-handbook-2018-with-notes.pdf/
[12] https://vpoglobal.com/2019/07/27/energy-experts-support-carbon-free-ammonia-as-a-marine-fuel/
[13] World Steel Association (2020): https://www.worldsteel.org/publications/position-papers/steel-s-contribution-to-a-low-carbon-future.html
[14] World Steel Association, press release Jan 2020: https://www.worldsteel.org/media-centre/press-releases/2020/Global-crude-steel-output-increases-by-3.4--in-2019.html
[15] IEA (2019), p 108

hydrogen and carbon monoxide as reducing agents. The European Fuel Cells and Hydrogen Joint Undertaking (FCH JU) identifies three potential routes to decarbonise steel production:

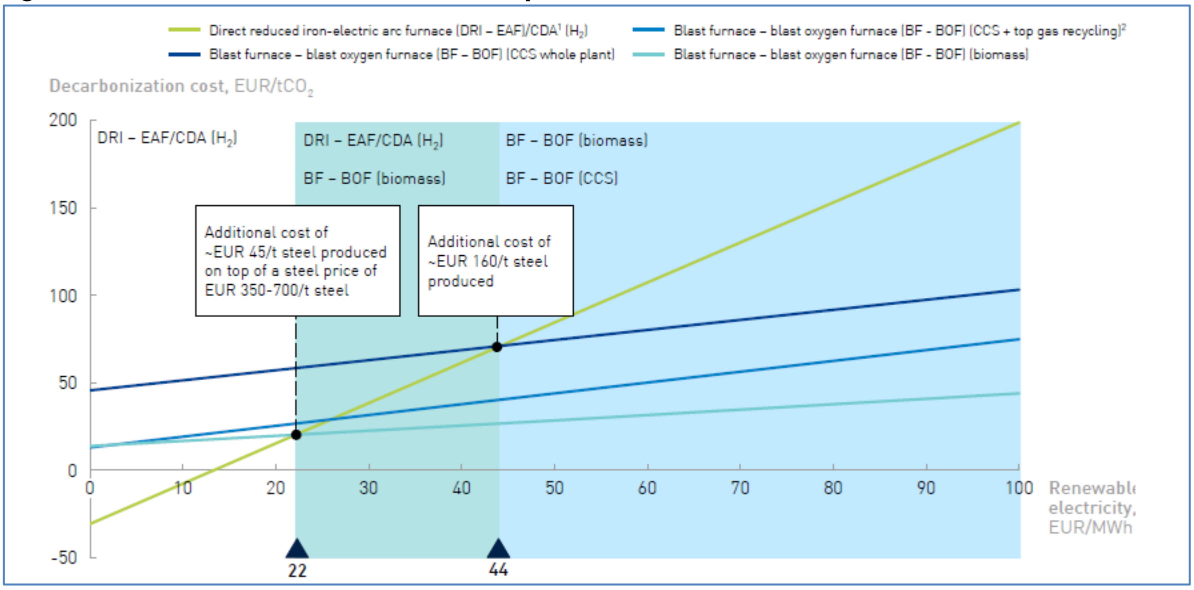
a) turning biomass into coke to replace fossil coal in blast furnaces;

b) use of carbon capture and storage (CCS) on blast furnace emissions, where suitable carbon storage is available and CCS is politically acceptable;

c) switching iron production to the DRI route and using decarbonised hydrogen produced via electrolysis.

FCH JU, with a focus on Europe, points out that the most economic route is dependent on the price of electricity used for electrolysis. As shown in Figure 2, they calculate that at an electricity price above €44/MWh, CCS is likely to be the most cost effective option, while with lower cost electricity, decarbonised hydrogen from electrolysis will be more competitive.[16] They also point out that the increase in the resulting cost of steel of between €45 and €160/tonne, on a current steel price of between €350 and €700/tonne would require a unified global approach to avoid penalising European steel producers.

Figure 2: Steel decarbonisation cost comparison



Source: FCH JU

Plans for decarbonisation of steel production are at a relatively early stage, and a number of pilot projects are being developed. For example, in 2018 the Hybrit project in Sweden started constructing a pilot plant to test DRI using hydrogen produced via electrolysis, with the objective of having a fully commercialised carbon-free steel process by 2035.[17] The Japanese Iron and Steel Federation in its 'Course 50' project is seeking to increase the proportion of hydrogen in blast furnaces, as well as using hydrogen for DRI and is considering the possibilities for CCS.[18]

Another 'hard to abate' industrial sector where hydrogen could play a role (albeit more limited than in the iron and steel industry) is in the cement industry. CO_2 emissions from global cement manufacture are estimated at 3.8 Gt/year (a little over 10 per cent of total global energy-related emissions), comprising 2.1 Gt from the chemistry of the process, 1.3 Gt from heat input and the balance from indirect

[16] FCH JU Hydrogen Roadmap (2019): https://www.fch.europa.eu/sites/default/files/Hydrogen%20Roadmap%20Europe_Report.pdf p42
[17] http://www.hybritdevelopment.com/
[18] https://www.jisf.or.jp/course50/outline/index_en.html

emissions from electricity used to operate machinery.[19] While direct process emissions can only be mitigated by carbon capture and storage, and renewable electricity will also be beneficial, decarbonised hydrogen may play a role in providing heat to the production process. The cement process requires intense heat (>1600°C) which could be provided by either an electric or hydrogen kiln furnace.[20] Since neither has yet been developed at commercial scale, it is not yet clear whether the electric or hydrogen routes will prove more cost effective, so more research and development is required in this area. Alternatives for decarbonisation of heat were considered in more detail in a separate 2018 OIES paper.[21]

What is a fuel cell?

A key technology for use of hydrogen in several applications is the fuel cell. Unlike traditional combustion technologies that burn fuel, fuel cells undergo a chemical process to convert hydrogen-rich fuel into electricity. Fuel cells do not need to be periodically recharged like batteries, but instead continue to produce electricity as long as a fuel source is provided.

A fuel cell works by passing hydrogen through the anode and oxygen through the cathode. At the anode, the hydrogen molecules are split into electrons and protons. The protons pass through the electrolyte membrane, while the electrons are forced through a circuit, generating an electric current and excess heat. At the cathode, the protons, electrons, and oxygen combine to produce water molecules.

Due to their high efficiency, fuel cells are very clean, with their only by-products being electricity, excess heat, and water. In addition, as fuel cells do not have any moving parts, they operate near-silently. Various alternative fuel cell technologies are in use or under development.[1]

2.2 Future use of decarbonised hydrogen in transport applications

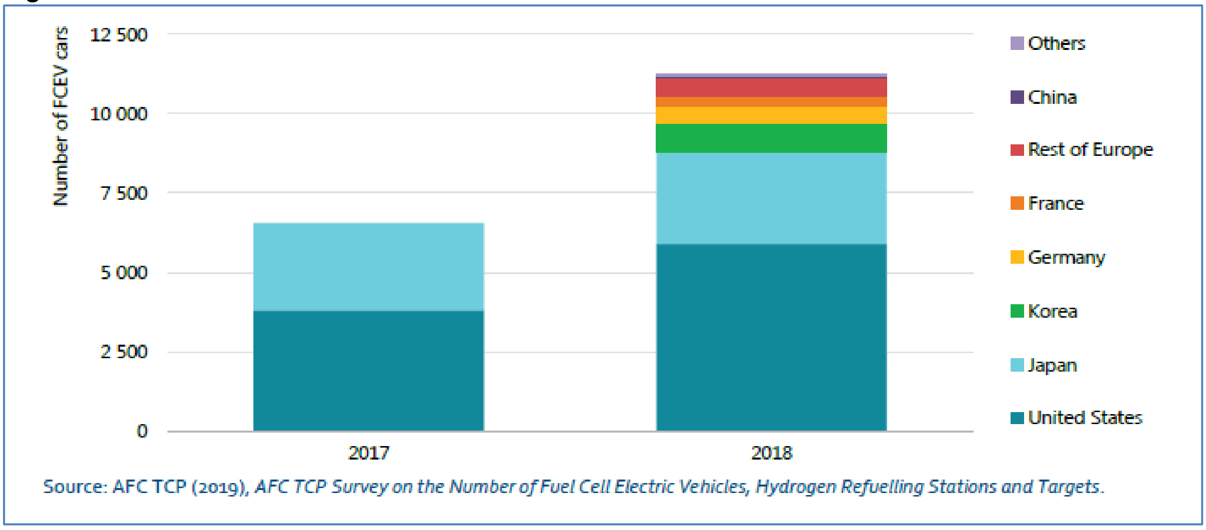
A promising new area in which hydrogen can play a significant role is in transport applications. The most well-developed of these to date is use in Fuel Cell Electric Vehicles (FCEV) for road, and potentially rail, transport. Hydrogen may play a role in shipping, either directly or in compounds such as ammonia. Consideration is being given to hydrogen-based liquid fuels for aviation, although development is at an early stage. These potential applications are described in more detail in this section.

2.2.1 Road and rail transport

For road transport, battery electric vehicles (BEV) are commonly accepted to be the most promising technology for decarbonising the light duty vehicle sector, but the most cost-effective route to decarbonising the long-distance, heavy-duty vehicle sector is less clear.[22] A direct comparison between BEVs and FCEVs may be unfair, as scale up of production and use of BEVs has been much more rapid than for FCEVs. As shown in Figure 3, the number of fuel cell cars in circulation nearly doubled in 2018 to reach 11,200 units, with the vast majority being in the United States and Japan, but despite this rapid growth rate, the total number is tiny compared to 5.1 million BEVs (in 2018) and the global car stock of more than 1 billion.[23]

[19] Energy Transitions Commission (ETC) (2018): http://energy-transitions.org/sites/default/files/ETC_Consultation_Paper_-_Cement.pdf
[20] ETC (2018)
[21] Honoré, A. (2018): https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/05/Decarbonisation-of-heat-in-Europe-implications-for-natural-gas-demand-NG130.pdf
[22] UK Committee on Climate Change (2019): https://www.theccc.org.uk/wp-content/uploads/2019/05/CCC-Zero-Emission-HGV-Infrastructure-Requirements-Ricardo-Energy-Environment.pdf
[23] IEA (2019) p 126

Figure 3: FCEV cars in circulation 2017–18

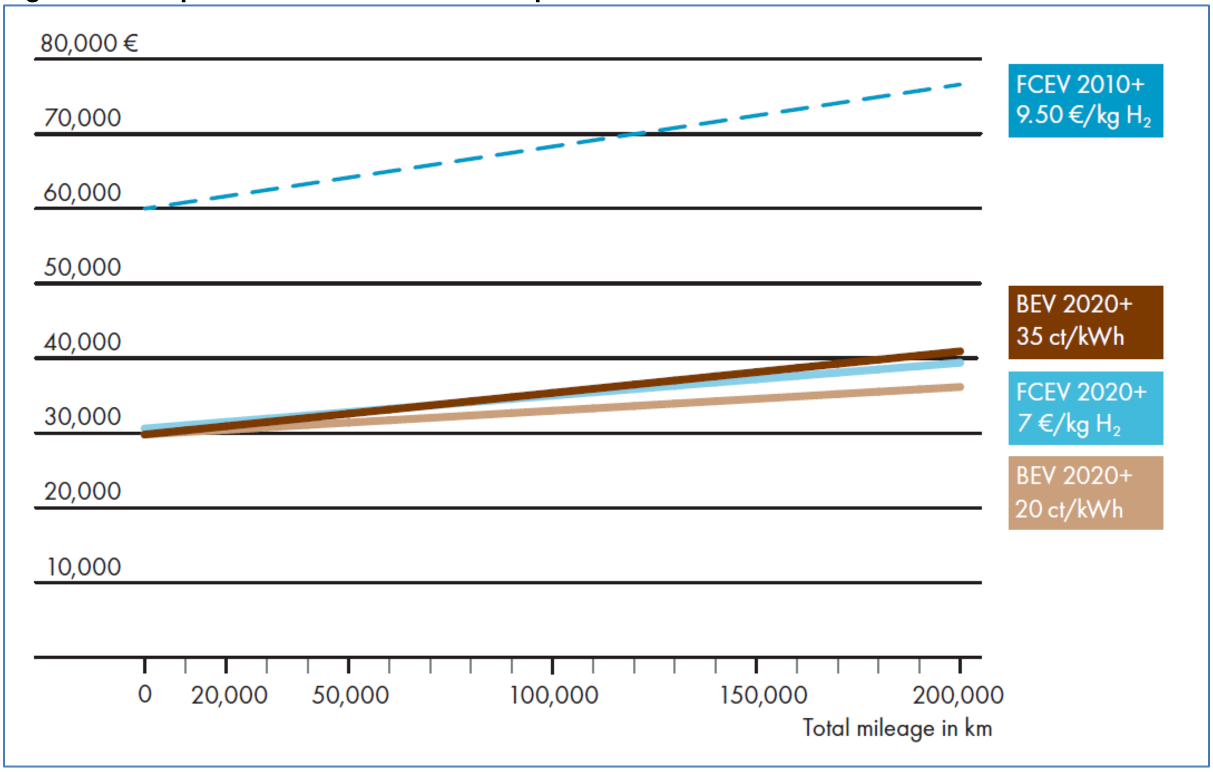


Source: IEA (2019)

The much more significant number of light duty BEVs has been largely driven by the lower purchase price and the rapid fall in the cost of batteries, where volume weighted average lithium-ion pack prices have fallen (in real terms 2018 $) from $1160 in 2010 to $176 in 2018.[24] The main drawback of BEVs has been the relatively short range and the long charging time when compared with FCEVs.[25] Range and charging time are more significant issues for long-haul commercial customers, who will also be concerned about total cost of ownership and availability of refuelling infrastructure. Total cost of ownership will be heavily dependent on the relative costs of renewable hydrogen and renewable electricity, as shown in Figure 4, in which Shell calculated the total ownership cost (purchase and fuel/energy cost) over a given mileage.[26] A H_2 price of €7/kg equates to an energy equivalent of 17c/kWh, whereas the graph shows equal cost of ownership for a BEV with an electricity price of 35c/kWh. So unless hydrogen electrolysis, with a conversion efficiency of around 80 per cent[27] can access significantly lower cost electricity than is available for vehicle charging, BEVs are likely to have a lower cost of ownership than FCEVs.

[24] Bloomberg New Energy Finance 2019: https://about.bnef.com/electric-vehicle-outlook/#toc-viewreport
[25] Shell Hydrogen Study (2017): https://hydrogeneurope.eu/sites/default/files/shell-h2-study-new.pdf
[26] Shell Hydrogen Study (2017): Figure 28
[27] Shell Hydrogen Study (2017): Figure 8

Figure 4: Comparison of lifetime ownership costs FCEV and BEV



Source: Shell Hydrogen Study (2017)

The remaining advantage of FCEV over BEV relates to range and speed of refuelling. A comprehensive study for the UK Committee on Climate Change[28] compared infrastructure requirements for hydrogen and battery pathways to meeting Heavy Goods Vehicle demand. The study found that the cumulative capital cost to 2060 for infrastructure for the hydrogen pathway (£3.4bn) was significantly lower than the equivalent cost (£21.3bn) for the battery pathway. The study also projected that, for the UK, the total cumulative costs (including both fuel and infrastructure) would be £123bn for hydrogen and £136bn for battery. It concluded that, at this stage there was no clear preference between electric and hydrogen vehicles as options to decarbonise the freight sector.

Thus, it appears that while hydrogen could play a role in decarbonisation of road transport, particularly for heavy-duty freight over long distances, there will need to be rapid progress in expanding the roll-out of FCEVs and reducing the costs if it is to compete with the decreasing cost and increasing range of BEVs.

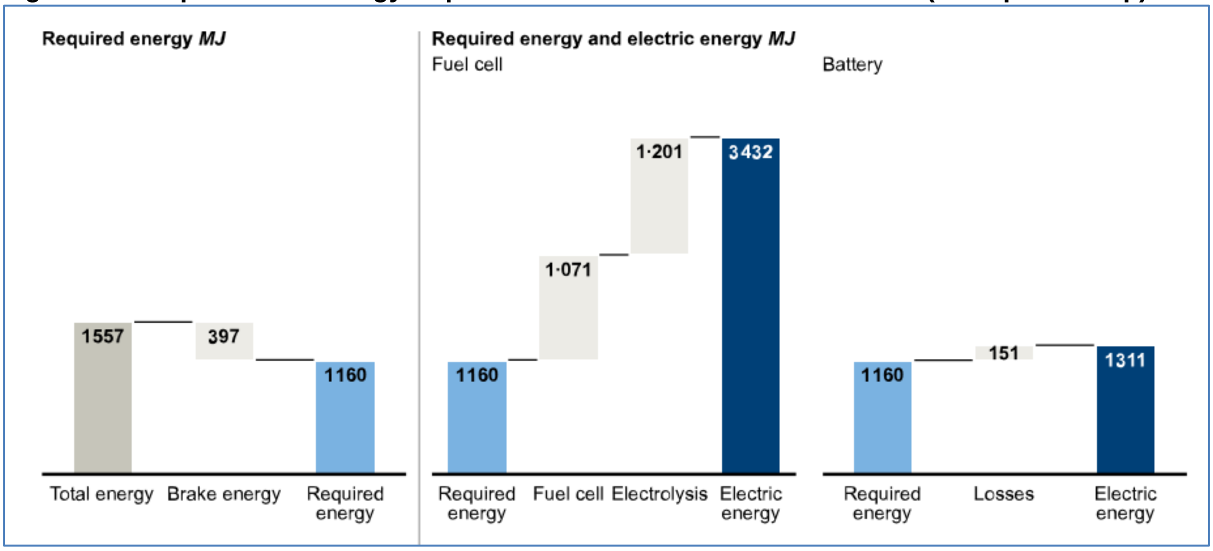
Similar considerations apply to the choice between battery-electric and hydrogen fuel cell options for railways, for situations where traditional fixed-infrastructure electrification is not suitable or not economic.[29] Different train manufacturers are piloting the two different technologies. Alstom has developed the 'iLint' hydrogen fuel cell units, two of which have been in revenue-earning service in Lower Saxony (northern Germany) since September 2018, with further units to be delivered by 2022. These units are able to travel up to 800km per day without refuelling. Prototype fuel cell trains are also being evaluated in the UK, Japan, South Korea and China. Bombardier (which may merge its rail business with Alstom) launched its prototype Talent 3 battery-powered unit, with a range of just 40km, on the German-Swiss border, and is intending to extend the range to 100km. Stadler is supplying 55

[28] UK CCC (2019): Zero Emission HGV Infrastructure Requirements https://www.theccc.org.uk/wp-content/uploads/2019/05/CCC-Zero-Emission-HGV-Infrastructure-Requirements-Ricardo-Energy-Environment.pdf
[29] See https://www.railwaygazette.com/in-depth/accelerating-the-decarbonisation-of-rail/55086.article

battery-operated trains with a maximum range of 150km for use in Schleswig-Holstein (northern Germany).[30] An advantage for battery use in rail transport is that, in many cases, the batteries can be recharged while running on those parts of the network which are electrified, with the batteries only being used for the non-electrified sections.

As with road transport, the battery electric alternative benefits from increased efficiency, and so the lower overall energy input required to provide the usable energy required, as illustrated in Figure 5. This shows, for an example railway journey, that for the same required transport energy the conversion losses in electrolysis and hydrogen fuel cells necessitate an energy input over double that required for battery power.

Figure 5: Comparison of energy requirements for fuel cells and batteries (example rail trip)



Source: Railway Gazette International (Nov 2019)

On the other hand, similar to road transport, hydrogen fuel cell trains are more suited to longer range applications, where the distance between recharging opportunities is around 200km or more.[31]

2.2.2 Maritime transport

Global CO_2 emissions from shipping are estimated at approximately 800 million tonnes per year currently and, under baseline/'business as usual' scenarios, are projected to grow to between 1100 and 1500 million tonnes per year by 2035.[32] The International Maritime Organisation is targeting at least a 40 per cent reduction (compared with a 2008 baseline) in carbon intensity of shipping by 2030 and at least a 70 per cent reduction by 2050. With the envisaged increased demand for maritime transport this equates to at least a 50 per cent reduction in total greenhouse gas (GHG) emissions from shipping by 2050 compared to the 2008 baseline.[33] Some ship operators have announced their intention to be carbon neutral by 2050 (e.g. Maersk[34]). The maritime industry is considering a range of alternative energy sources as ways to decarbonise, as shown in Table 1.

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[30] https://www.stadlerrail.com/en/media/article/stadler-supplies-55-battery-operated-flirt-trains-for-theschleswig-holstein-local-transport-association/522/
[31] Railway Gazette International (Nov 2019)
[32] International Transport Forum: Decarbonising Maritime Transport (2018): https://www.itf-oecd.org/sites/default/files/docs/decarbonising-maritime-transport-2035.pdf
[33] https://theicct.org/sites/default/files/publications/IMO_GHG_StrategyFInalPolicyUpdate042318.pdf
[34] https://www.maersk.com/news/articles/2019/06/26/towards-a-zero-carbon-future

Table 1: CO_2 emission impact of alternative marine fuels

Measures	CO_2 emission reductions
Advanced biofuels	25-100%
LNG	0-20%
Hydrogen	0-100%
Ammonia	0-100%
Fuel cells	2-20%
Electricity	0-100%
Wind	1-32%
Solar	0-12%
Nuclear	0-100%

Source: International Transport Forum (2018), Table 4

For short range shipping (e.g. short ferry crossings) battery electric propulsion is likely to be viable, and several examples are already in operation.[35] For long-range, trans-ocean shipping, even with continuing evolution of technology, batteries are unlikely to provide a feasible solution.

Pure hydrogen, probably stored in liquid form, could be used in fuel cells or as a replacement for heavy fuel oil (either partially or completely) in internal combustion engines.[36] As an alternative, ammonia, made from renewable hydrogen, is also being considered as a potential marine fuel. The proponents of ammonia[37] cite the following advantages of ammonia over liquid hydrogen:

- it is an abundant commodity with existing infrastructure for production, storage and transport;
- it has a higher volumetric density, allowing for longer voyages without refuelling;
- it can be stored as a liquid at a more moderate temperature (-33˚C at atmospheric pressure) than hydrogen (-252˚C);
- it can also be used in engines and fuel cells.

Despite these claimed advantages, development of ammonia as a maritime fuel is at an early stage. A Dutch consortium, including the fertiliser manufacturer, Yara, is undertaking a two year project with the objective of demonstrating the technical feasibility and cost effectiveness of an ammonia marine tanker fuelled by its own cargo.[38]

As shown in Figure 6, calculations by the IEA suggest that in the long-term, an internal combustion engine fuelled by ammonia may provide the lowest overall cost for long-haul shipping.

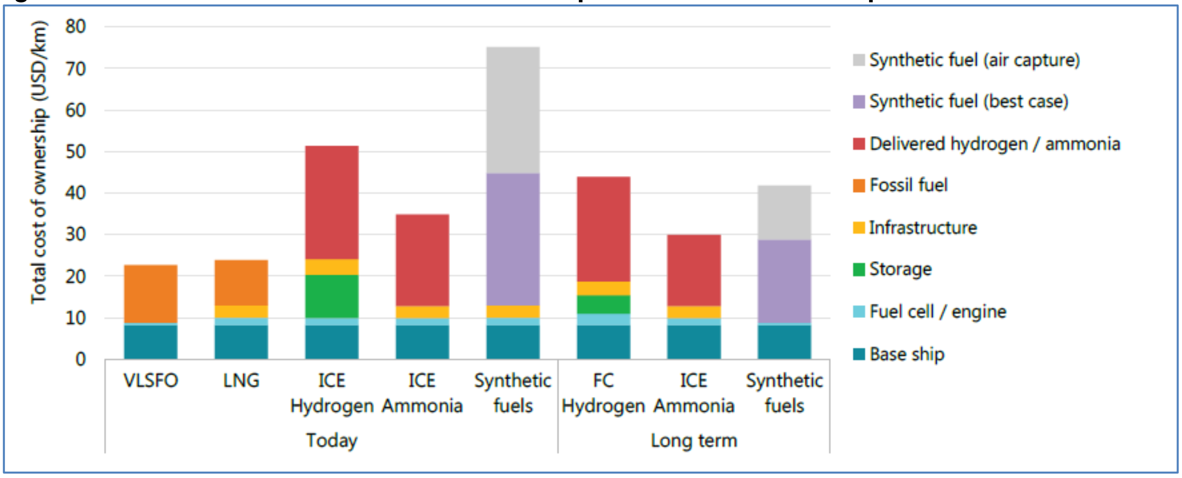
[35] See for example: the first electric ferry in Norway entered service in 2015 http://www.ppmc-transport.org/battery-electric-car-ferry-in-norway/. 'E-Ferry Ellen' is claimed to be the ship with the largest battery capacity able to travel 22 nautical miles without recharging with a 4.3 MWh battery https://www.cnbc.com/2019/08/19/the-worlds-largest-all-electric-ferry-completes-maiden-voyage.html .

[36] ITF, Decarbonising Maritime Transport (2018)

[37] See, for example Sailing on Solar - could green ammonia decarbonise international shipping, EDF (2019): https://europe.edf.org/news/2019/02/05/shipping-can-reduce-climate-pollution-and-draw-investment-developing-countries

[38] https://vpoglobal.com/2019/07/27/energy-experts-support-carbon-free-ammonia-as-a-marine-fuel/

Figure 6: Current and future costs of ownership for bulk carrier fuel options



Source: IEA (2019)

2.2.3 Aviation

Probably the hardest form of transport to decarbonise is aviation, on account of the very high energy density required. In 2018, aviation is estimated to have produced around 895 million tonnes of CO_2 emissions globally, around 12 per cent of total emissions from transport (road transport being 74 per cent of total transport CO_2 emissions).[39] Direct use of hydrogen in aircraft would require completely new aircraft design and airport refuelling infrastructure, so current thinking on decarbonisation of aviation focuses on 'e-fuels'.[40] These fuels are synthetic liquid fuels, manufactured from renewable hydrogen and biogenic or atmospheric CO_2, which can be used in place of, or blended with existing aviation fuels. These synthetic liquid fuels are expected to be much more expensive (€2100/tonne in 2050) compared with existing aviation fuel (€600/tonne), at which level there is expected to be a significant reduction in demand for aviation compared with a business as usual scenario.[41]

2.3 Future use of decarbonised hydrogen in space heating applications

Global energy demand in buildings in 2018 is estimated at 3101 million tonnes of oil equivalent (mtoe)[42] (around 36000 TWh, or 3500 Bcm of natural gas equivalent). By 2040, this is estimated to grow to 3758 mtoe under the IEA Stated Policies Scenario, and to fall slightly to 2709 mtoe in the Sustainable Development Scenario. Natural Gas currently supplies around 25 per cent of demand in buildings globally, while electricity supplies around 35 per cent. A precise figure for space heating (as opposed to lighting and other energy use in buildings) is difficult to estimate accurately, but in EU households it is estimated that heating and hot water account for 79 per cent of total final energy use.[43] Figure 7 shows an estimate of the share of space heating in total building demand and the share of gas in total space heating demand.[44]

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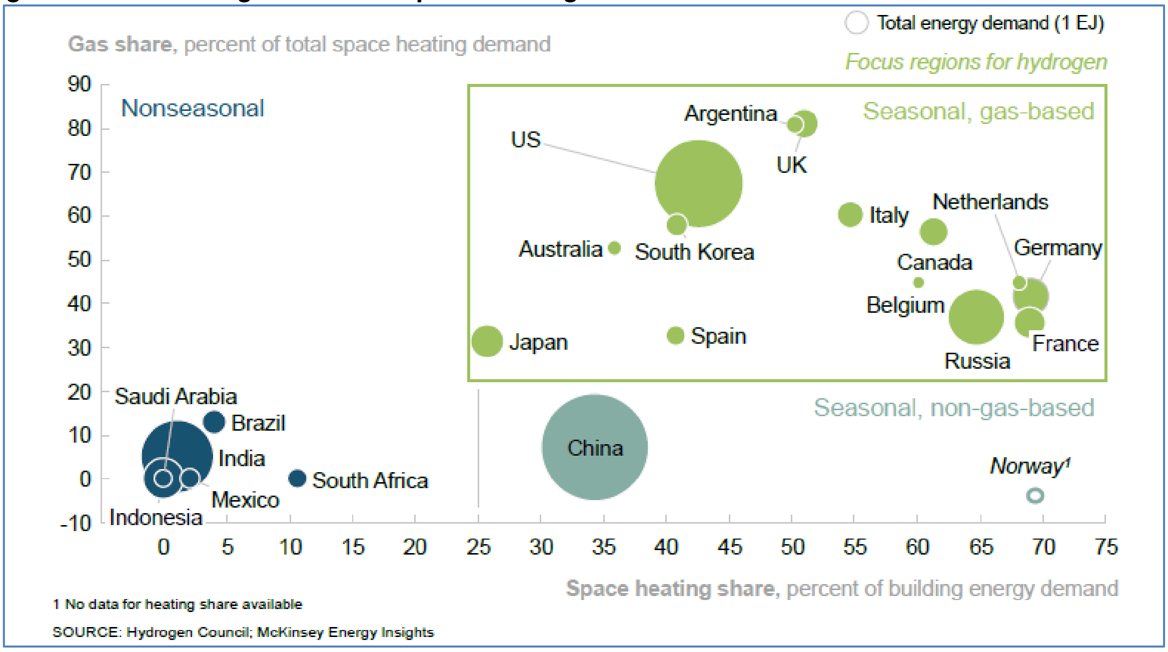
[39] https://www.atag.org/facts-figures.html
[40] Transport and Environment (2018): https://www.transportenvironment.org/sites/te/files/publications/2018_10_Aviation_decarbonisation_paper_final.pdf p 16
[41] Transport and Environment (2018) p 26
[42] IEA World Energy Outlook, November 2019
[43] https://ec.europa.eu/energy/en/topics/energy-efficiency/heating-and-cooling
[44] Hydrogen Council November 2017: https://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf

Figure 7: Estimated gas share of space heating demand



Source: Hydrogen Council: Hydrogen scaling up (Nov 2017)

Various studies in Europe[45] have assessed the potential to decarbonise the heating sector by large scale conversion to electricity. They have concluded that an 'all electric' solution will be higher cost than continuing to use gaseous fuels, and, in some cases, it may not be feasible to build the required re-inforcements to electricity transmission and distribution infrastructure. It is recognised, however, that continuing to burn significant quantities of fossil-derived natural gas will not be consistent with decarbonisation targets. In this context, it is seen that decarbonised hydrogen can play a role and various studies and demonstration projects are evaluating the potential roles further.

The most straightforward way to start using decarbonised hydrogen is to blend it into the existing natural gas grid. In Europe, various demonstration projects[46] are testing blends up to 20 per cent by volume, to show that the blend can be accommodated in existing infrastructure and end-user equipment with little or no modification. While this will be useful to provide an outlet for initial decentralised production of renewable hydrogen, it will not provide a solution for deep decarbonisation of the heat/buildings sector. With the lower energy density of hydrogen compared with natural gas, 20 per cent by volume only equates to around 7 per cent by energy content. While 20 per cent blend (and particularly where the blend percentage varies over time) may be acceptable in some limited parts of the network, it will not be acceptable for some systems and some types of end user equipment (see Section 4 below).

A more challenging alternative is to convert (all or part of) the existing natural gas network to carry 100 per cent hydrogen. This was studied in detail in the H21 project in the UK, initially for the city of Leeds and subsequently for several towns and cities in the north of England.[47] This project envisaged conversion of over 3.7 million domestic customers (and 37,000 non-domestic customers) from their existing natural gas supply to 100 per cent hydrogen. It planned a street-by-street conversion programme over seven years between 2028 and 2035, in a similar way to the conversion of households from manufactured gas (itself a hydrogen blend) to natural gas in the 1960s and 70s. The study found

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[45] See for example, UK Energy Networks Association, Oct 2019: http://www.energynetworks.org/assets/files/gas/Navigant%20Pathways%20to%20Net-Zero.pdf and Deutsche Energie Agentur, Oct 2018: https://www.dena.de/fileadmin/dena/Dokumente/Pdf/9283_dena_Study_Integrated_Energy_Transition.PDF
[46] For example, Hydeploy at Keele University, UK - https://hydeploy.co.uk/ and GRHYD at Dunkerque, France https://www.engie.com/en/businesses/gas/hydrogen/power-to-gas/the-grhyd-demonstration-project
[47] https://www.h21.green/wp-content/uploads/2019/01/H21-NoE-PRINT-PDF-FINAL-1.pdf

that the distribution infrastructure, largely now comprising polyethylene pipes, would be suitable for carrying 100 per cent hydrogen, but envisaged that a new hydrogen transmission network would be built to carry hydrogen from the production facilities to the city gates. A major hurdle, however, is likely to be consumer acceptance, particularly given the significant up-front costs of new boilers and other equipment able to run on hydrogen. A report published in November 2018 proposed a budget of £250m for a Front End Engineering and Design Study, but this has not yet been supported. While small scale testing continues under the H21 project, the main focus for potential hydrogen use in the UK appears to have switched to supplying hydrogen to industrial users.[48] The challenges of large scale conversion of existing natural gas infrastructure as envisaged by projects like H21 is discussed further in Section 4 below.

A third alternative for use of hydrogen in space heating is via the production of renewable methane, as described in more detail in an earlier OIES paper.[49] This concept has been demonstrated in various projects, including three locations in Europe under the 'Store&Go' project, partly funded under the EU Horizon 2020 programme.[50] Making renewable methane has the benefit of being invisible to end-users, but the disadvantage of requiring an additional processing step thereby reducing efficiency and increasing cost.

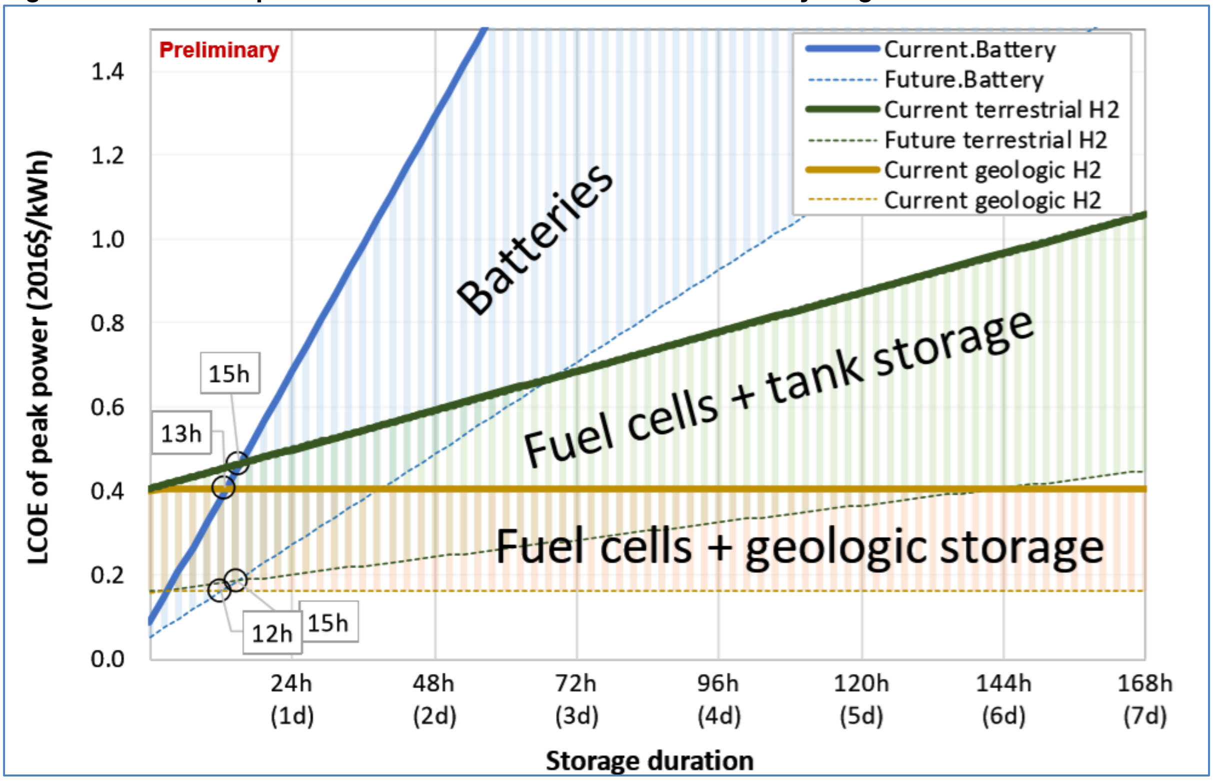
Thus it is likely that decarbonised hydrogen will play some role in decarbonisation of the heating sector, but there remain several barriers to all routes to decarbonisation of heat, whether using hydrogen, renewable methane or electricity. Government policy and consumer preferences are likely to play a key role in determining the extent and nature of the role of hydrogen. The preferred solution is also likely to vary by country and region, particularly based on factors like the seasonality of demand and existing infrastructure.

2.4 Future use of decarbonised hydrogen for power generation

To complete the list of potential applications, decarbonised hydrogen can also be used as a fuel for power generation, to provide load balancing for intermittent renewables, particularly for seasonal storage over longer time periods than is possible with batteries. For short-term storage, batteries have a much higher round trip efficiency[51] (at least 80 per cent, and even up to 95 per cent) than hydrogen storage (less than 50 per cent and can be as low as 35 per cent). Despite this efficiency difference, it has been calculated that hydrogen storage is lower cost than battery storage for durations longer than 15 hours, as shown in Figure 8[52]. If geological storage (e.g. salt caverns) is available this provides a significantly lower cost storage option than storing hydrogen in tanks.

[48] See https://www.zerocarbonhumber.co.uk/ and https://hynet.co.uk/
[49] Lambert, M. (2018): https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/10/Power-to-Gas-Linking-Electricity-and-Gas-in-a-Decarbonising-World-Insight-39.pdf
[50] https://www.storeandgo.info/about-the-project/
[51] NREL (2019): https://www.nrel.gov/docs/fy19osti/73520.pdf slide 4
[52] NREL (2019) slide 10

Figure 8: Economic performance benchmark current & future hydrogen and batteries



Source: NREL (2019)

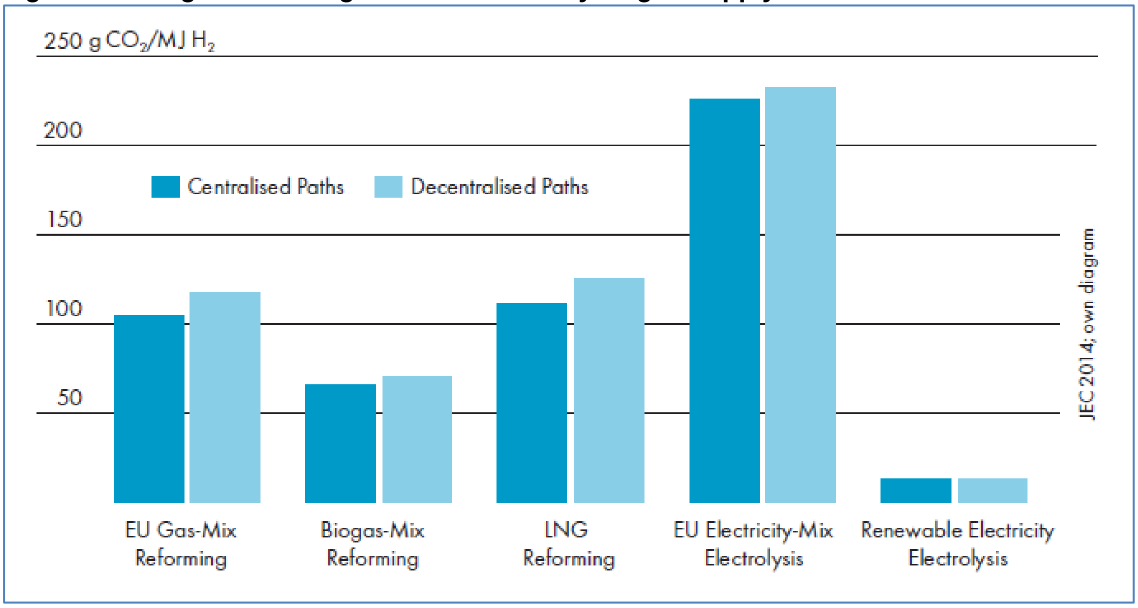
It should also be noted that use of renewable hydrogen in power generation could provide a rapid pathway to scale up production of renewable hydrogen: a 500MW power plant would create a hydrogen demand equivalent to 455,000 fuel cell vehicles or to heat over 200,000 homes in the UK.[53]

3. Potential production pathways for renewable hydrogen

95 per cent of all hydrogen produced today is from fossil fuels (76 per cent from natural gas and 23 per cent from coal). Just two per cent is currently produced by electrolysis, since it is generally a higher cost.[54] The greenhouse gas emissions from current hydrogen production methods are significant at around 830 million tonnes per year of annual CO_2 emissions.[55] In the context of decarbonisation, existing production processes will need to be retrofitted with CCUS, or alternative production technologies must be developed at scale. Biogas or biomethane could be used as a feedstock for methane reforming, but this would also benefit from the addition of CCUS, and is probably not the most effective use of scarce biogas/biomethane resources.[56] Electrolysis using the current EU electricity mix would have higher unit GHG emissions than reforming of natural gas, as shown in Figure 9, whereas electrolysis using purely renewable electricity would have negligible emissions.

[53] IEA (2019) p 157
[54] IEA (2019)
[55] https://www.iea.org/fuels-and-technologies/hydrogen
[56] Lambert, M. (2017): https://www.oxfordenergy.org/wpcms/wp-content/uploads/2017/06/Biogas-A-significant-contribution-to-decarbonising-gas-markets.pdf

Figure 9: Unit greenhouse gas emissions of hydrogen supply



Source: Shell Hydrogen Study (2017)

Three approaches to low- or zero-carbon hydrogen production are currently being considered:[57]

- steam methane reforming (SMR) or autothermal reforming (ATR), which convert methane to hydrogen, but (unlike current practice) now with the associated CO_2 being captured and stored. This is currently the approach which could most quickly be deployed at scale, particularly by retrofitting CCUS to existing reforming facilities. There are 19 CCUS facilities in operation globally, four under construction and 28 under development, with an estimated capture capacity of 96 million tonnes of CO_2 per year.[58] Many of the existing CCUS operations, particularly in North America, inject the CO_2 for enhanced oil recovery, but other examples, notably at Sleipner in Norway (in operation since 1996) and at Gorgon in Australia, have proven the feasibility of storing CO_2 at scale. The main drawback is that CCUS is not suitable in all locations, either on account of lack of suitable storage facilities or lack of political/stakeholder acceptability (for example in much of continental Europe). Hydrogen from methane reforming with CCUS is sometimes referred to as 'blue hydrogen'.
- Electrolysis uses electricity to split water into hydrogen and oxygen. If the electricity used is zero carbon, the resulting hydrogen is also considered zero carbon. Such zero carbon hydrogen is sometimes referred to as 'green hydrogen'. While several demonstration projects up to 10MW scale have been built or are under construction, much greater scale up of electrolysis (to many gigawatts (GW) of capacity) and significant cost reduction is required in order to meet aspired green hydrogen production levels.[59]
- A possible third route to low carbon hydrogen production is methane pyrolysis. This technology, which is still in the very early stages of development, envisages cracking methane into hydrogen and solid carbon. Proponents of the technology (including Gazprom[60]) claim that the

[57] Poyry (2019): https://www.poyry.com/sites/default/files/zukunft_erdgas_key_to_deep_decarbonisation_0.pdf
[58] Global CCS Institute 2019: https://www.globalccsinstitute.com/news-media/press-room/media-releases/new-wave-of-ccs-activity-ten-large-scale-projects-announced/
[59] See OIES/SGI (2019): https://www.oxfordenergy.org/wpcms/wp-content/uploads/2019/10/A-mountain-to-climb-Tracking-progress-in-scaling-up-renewable-gas-production-in-Europe-NG-153.pdf
[60] http://en.unecon.ru/sites/default/files/en/maximilian_kuhn_the_role_of_h2_from_natural_gas.pdf

solid carbon will be easier to handle, use and store than CO_2, but this technology is still only demonstrated at laboratory scale.

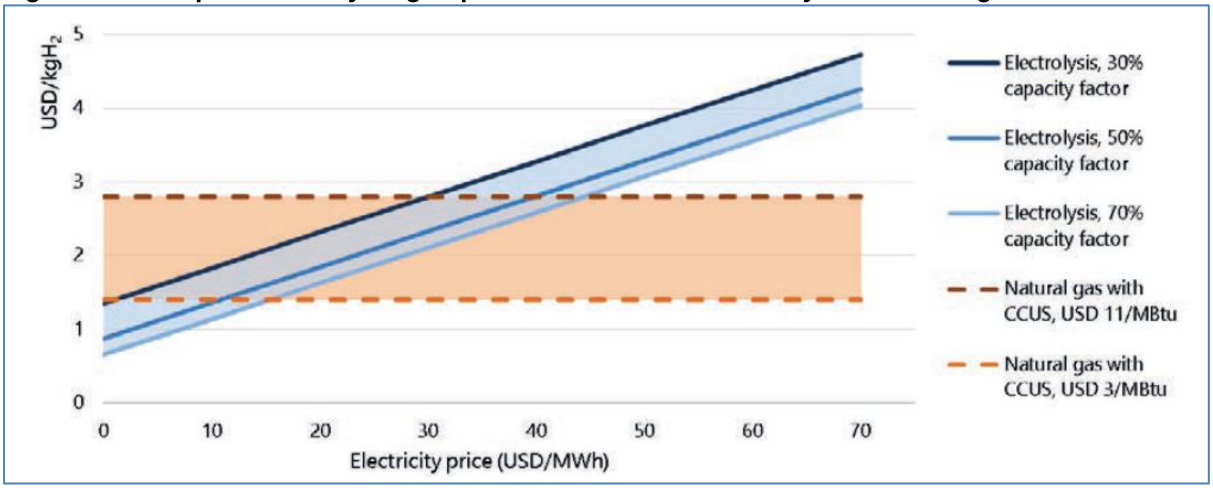
A comparison of the projected long-term (by 2050) production costs and efficiency of the three pathways is shown in Table 2[61] and a further comparison of how hydrogen production costs varies with gas and electricity prices is shown in Figure 10. (Note that $2/kg equates to €45/MWh and $3/kg to €67/MWh, indicating that the two analyses are broadly consistent).

Table 2: Comparison of low carbon production projected (in 2050) cost and efficiency

	Capex (EUR/kW H_2)	Opex (EUR/kW H_2)	Efficiency %	Levelised cost (EUR/MWh)
SMR with CCS	934	37	78	47
Pyrolysis	1261	22	55	60
Electrolysis	544	31	80	66

Source: Pöyry (2019)

Figure 10: Comparison of hydrogen production costs: electricity and natural gas with CCUS



Source: IEA (2019)

For electrolysis, a cost of electricity of €30/MWh is likely to result in a hydrogen cost in the range €50-60/MWh. Thus it is clear that, in order to be competitive, other advantages of using hydrogen over electricity will have to be demonstrated, for example energy density, ease of storage or particular suitability to the application in question.

It can also be seen that SMR/CCS and electrolysis have similar efficiencies, but the levelised cost of SMR/CCS is likely to be significantly lower at current gas and electricity prices. Since it is also expected to be easier to build methane reforming with CCS at scale in the near term, it is reasonable to conclude that initial production of low carbon hydrogen will mainly be from SMR (or ATR) with CCS. In the longer term, assuming appropriate scale up and cost reduction of renewable electricity and electrolysis, it will be preferable for this to become the dominant production technology to minimise the continued use of fossil fuels. This conclusion is consistent with several other studies.[62]

Having reached that conclusion, there remains a need for rapid scale up of all low carbon hydrogen production methods. Failure to demonstrate the technologies at increasing scale runs the risk that, in

[61] Poyry (2019): https://www.poyry.com/sites/default/files/zukunft_erdgas_key_to_deep_decarbonisation_0.pdf
[62] See for example: Navigant, Gas for Climate, 2019 https://www.gasforclimate2050.eu/files/files/Navigant_Gas_for_Climate_The_optimal_role_for_gas_in_a_net_zero_emissions_energy_system_March_2019.pdf

the absence of a credible alternative and given its inherent cost advantage, electricity will take an increasing share of demand as the energy system decarbonises.

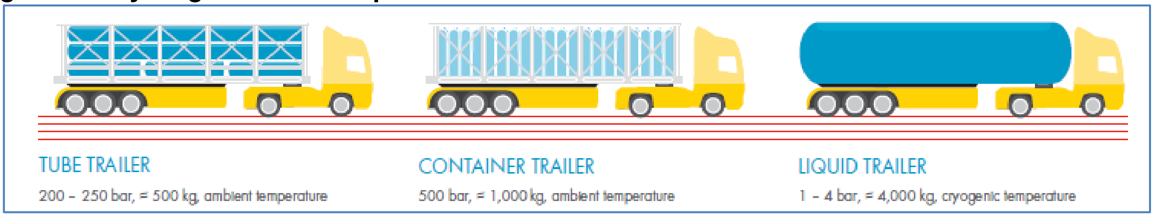
4. Alternatives for hydrogen transport

Most hydrogen today is consumed in the location where it is manufactured (85 per cent) or transported via trucks or pipelines (15 per cent).[63] There are over 4500km of hydrogen pipelines in operation globally, of which over 2600km are in USA, the next largest country being Belgium with around 600km.[64] Thus there is experience of transporting hydrogen by road and pipeline, but it should be noted that it is not necessarily straightforward to convert an existing natural gas pipeline to carry hydrogen, as discussed further below.

4.1 Transport in liquid or compressed form

Hydrogen can also be transported (normally by road, but also potentially by rail or ship) in tanks as either compressed gas or liquefied hydrogen. Figure 11 illustrates the various types of road tanker currently in use for transporting hydrogen.

Figure 11: Hydrogen road transport alternatives



Source: Shell Hydrogen Study (2017)

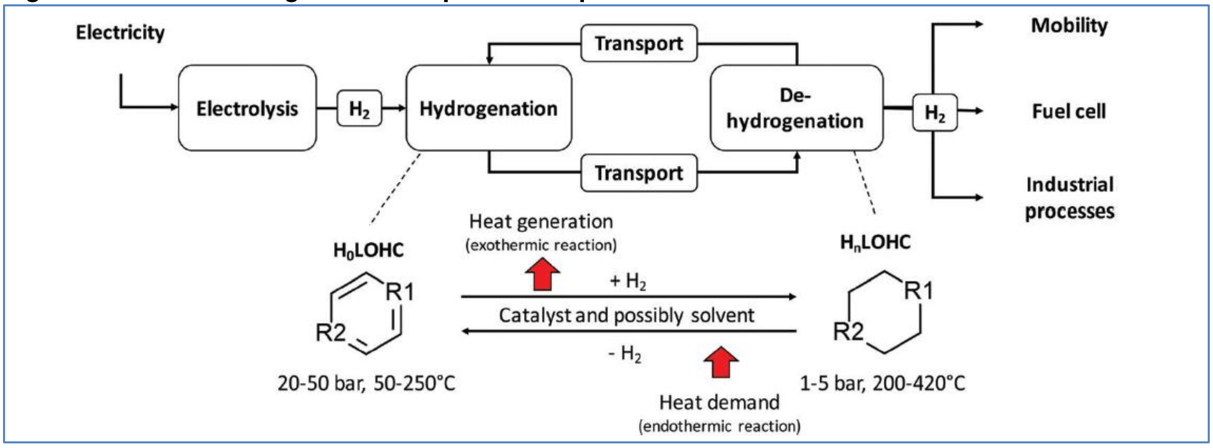
A typical road tanker can carry around 26m^3 of compressed hydrogen or 50m^3 of liquid hydrogen.[65] In compressed form (at 250bar), this is equivalent to around 20 MWh, whereas a similar sized compressed natural gas tanker (also at 250 bar) would carry around 65 MWh, a little over three times the energy content. In liquid form, this is equivalent to around 140 MWh, whereas a similar sized LNG tanker would carry around 350 MWh.

A demonstration project (HySTRA/Hydrogen Energy Supply Chain)[66] is planning to generate hydrogen (initially from brown coal) in Australia, liquefy it and ship the liquid hydrogen to Japan. As part of that project, the first ocean going ship (Suiso Frontier) constructed by Kawasaki Heavy Industries in Japan was launched in December 2019.[67] The ship is 116m long, weighing approximately 8000 tonnes, designed to carry 1250m^3 of liquid hydrogen, an energy content of around 3.5 GWh. The physical size and weight of the vessel is similar to a small scale LNG carrier[68] which can carry 7500m^3 LNG, an energy content of around 50 GWh. Since there is not yet any carbon capture and storage associated with hydrogen production from coal, and the supply chain involves transporting a relatively small quantity by both road and ship, this is clearly not yet a low carbon source of hydrogen. However, when it begins regular operation, scheduled for late 2020 or 2021 it will provide valuable experience of long distance maritime transport of liquid hydrogen. The project developers estimate the cost of liquid hydrogen transport via the demonstration route to be around $10/kg (equivalent to over €200/MWh), but suggest that this could fall to around $2-3/kg (€50-70/MWh) by 2050.[69]

[63] IEA (2019)
[64] Shell Hydrogen Study (2017)
[65] Shell (2017)
[66] http://www.hystra.or.jp/en/project/ and https://hydrogenenergysupplychain.com/
[67] https://newatlas.com/marine/kawasaki-worlds-first-liquid-hydrogen-transport-ship/
[68] For example, Coral Anthelia, https://www.anthonyveder.com/fleet/coral-anthelia/
[69] Kawasaki HI presentation to Japan Hydrogen Ministerial Sept 2019

As an alternative for long distance transportation, hydrogen can also be converted to ammonia or a liquid organic hydrogen carrier (LOHC). The basic concept of LOHC, as illustrated in Figure 12,[70] is to react renewable hydrogen with another substance to produce a liquid which can be readily stored and transported. Transport is normally at or near to atmospheric temperature and pressure, so can be by road, rail, ship or pipeline in a similar way to oil products. The conversion process is then reversed to recreate the renewable hydrogen for distribution and sale to end-users. Most of the dehydrogenated carrier material is then transported back to the starting point for the cycle to be repeated.

Figure 12: LOHC storage and transport concept

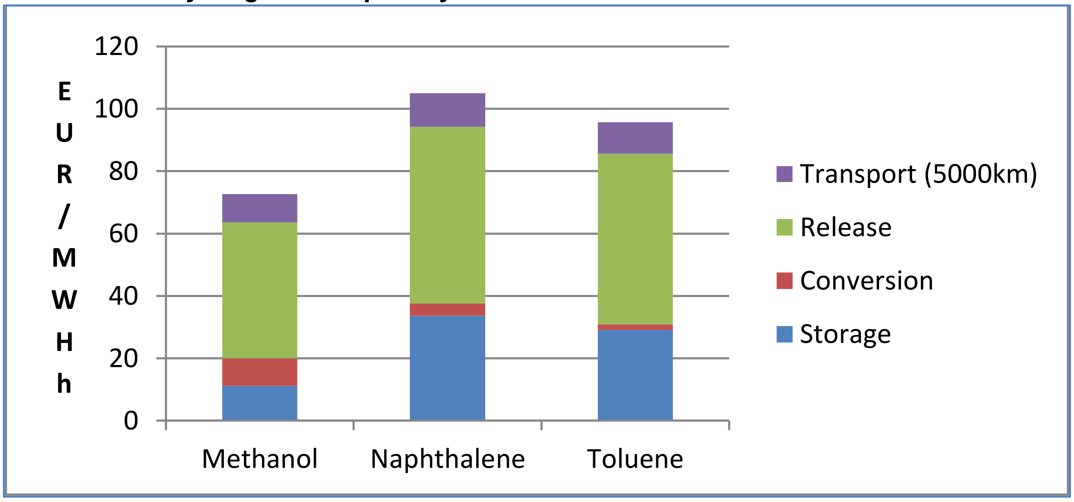


Source: Energy Environ. Sci 2019, 12, 290

There are several candidates for use as an LOHC, but the lowest cost alternatives are currently thought to be methanol, naphthalene and toluene.[71] Figure 13 shows the estimated costs of hydrogen transport by LOHC. It can be seen that the majority of the cost is attributable to the conversion and release of hydrogen at the destination, but the cost of transport is small, emphasising that this system is only suitable for very long-distance transport. The costs are clearly very high, but at this stage, the total in the range €80-100/MWh is significantly lower than over €200/MWh for shipping liquid hydrogen. For shorter distances, pipelines are clearly the preferred option: IEA estimates a pipeline transport cost of around $0.5/kg (~€10/MWh) per 1000km of transport by pipeline.[72]

[70] Energy and Environmental Science (2019): https://pubs.rsc.org/en/content/articlelanding/2019/ee/c8ee02700e#!divAbstract
[71] Energy and Environmental Science (2019) – as above
[72] IEA (2019)

Figure 13: Cost of hydrogen transport by various candidate LOHCs



Source: Author's analysis, data from Energy and Environmental Science, 2019

A Japanese consortium led by Chiyoda Corporation is developing a demonstration LOHC supply chain using toluene / methylcyclohexane as the carrier.[73] The project achieved the milestone of delivering the first foreign-produced hydrogen to Japan in December 2019, with the methylcyclohexane having been manufactured in Brunei. The dehydrogenation plant in Japan is currently in commissioning.

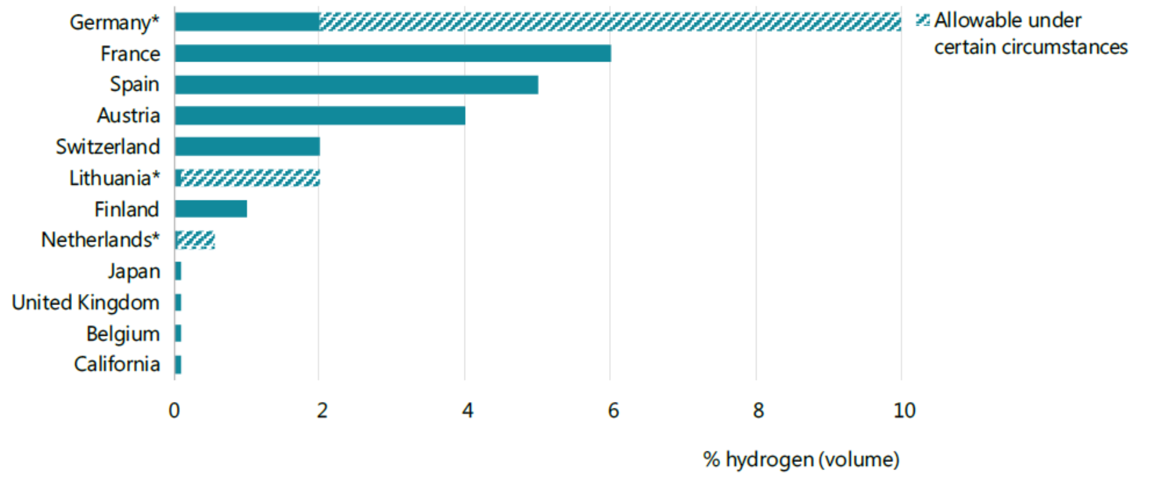
4.2 Transport / distribution by pipeline and conversion of existing gas pipelines

As noted above, with over 4000km of hydrogen pipelines in operation globally, the technical ability to construct and operate hydrogen pipelines safely has been well proven. For short distances, provided there is sufficient demand to justify the pipeline construction cost, pipeline distribution is likely to be the preferred alternative. For distribution of hydrogen to refuelling stations in an urban area (e.g. Los Angeles), it has been proposed that a very high pressure (at around 1000 bar) distribution network may be more economic than distribution by truck which would require storage and compression at each refuelling station.[74] There is clearly no technical constraint on the ability to transport hydrogen by pipeline, so it will be an economic decision on a case by case basis as to whether the expected level of hydrogen demand justifies the capital cost of construction compared with alternative transport options considered in Section 4.1.

Several studies have considered the possibility of conversion of existing natural gas pipelines to carry hydrogen. These studies cover a range of possibilities from blending up to around 20 per cent hydrogen with natural gas, to a complete switch to 100 per cent renewable hydrogen.[75]

[73] The AHEAD Project: https://www.ahead.or.jp/en/
[74] National Renewable Energy Laboratory, December 2019: https://www.sciencedirect.com/science/article/pii/S1361920918311982?via%3Dihub
[75] For example, blends have been tested at the GRHYD project in France: http://grhyd.fr/ and Hydeploy in UK: https://hydeploy.co.uk/. H21 North of England Project has considered conversion of several UK cities to 100 per cent hydrogen: https://www.h21.green/

Figure 14: Current limits on hydrogen blending in natural gas networks



* Higher limit for Germany applies if there are no CNG filling stations connected to the network; higher limit for the Netherlands applies to high-calorific gas; higher limit for Lithuania applies when pipeline pressure is greater than 16 bar pressure.

Source: IEA (2019)

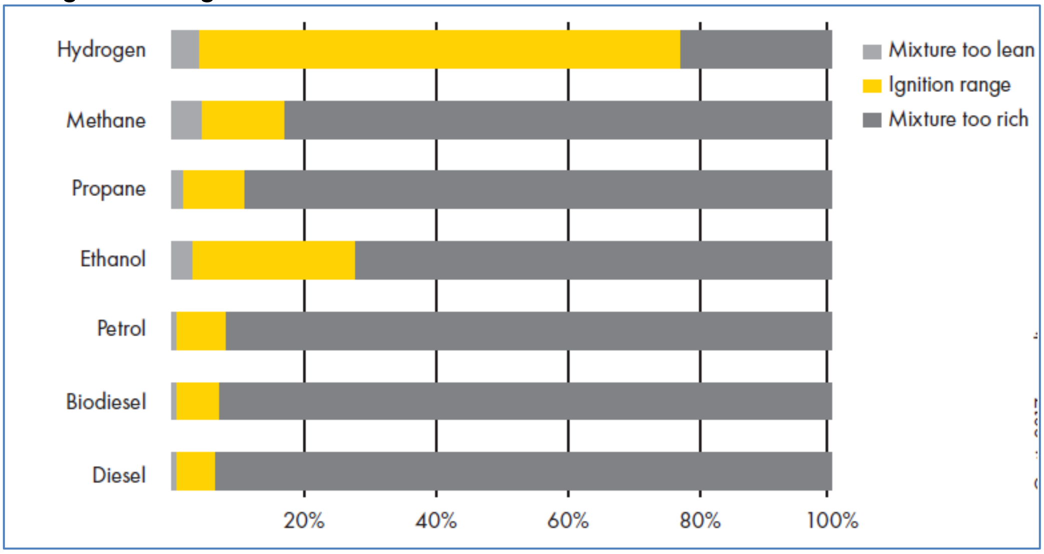
Current natural gas pipeline regulation varies from country to country, but typically stipulates very low levels of hydrogen blending, as illustrated in Figure 14. There are several reasons for this, which broadly fall into three categories:[76] (a) the risk of hydrogen causing embrittlement of metal natural gas pipelines, storage tanks and other system components; (b) the risk of hydrogen molecules, which are much smaller than methane molecules, leaking through seals which are able to contain methane; (c) the inability of some end-user equipment to accept higher, or variable, quantities of hydrogen.

The increased risk of leakage of hydrogen, on account of its physical properties, is an important consideration, particularly since the ignition range of hydrogen in air is much wider than natural gas and other fuels, as shown in Figure 15.[77] This underlines the importance of very careful analysis of the entire natural gas system before deciding that it is suitable to be converted to carry hydrogen.

An assessment of the range of acceptable levels of hydrogen blend for each key system component is illustrated in Figure 16.[78] This chart illustrates clearly that there are very few system components, apart from plastic pipelines, which can be converted to high percentages of hydrogen without thorough technical checks and / or further research. Some key components designed to run on natural gas, notably gas turbines, compressor stations and compressed natural gas (CNG) tanks can only accept levels of hydrogen in natural gas well below five per cent. Gas turbines can be adapted to run on hydrogen, even up to 100 per cent hydrogen,[79] but the turbine and other system components must be configured for a specified gas composition. It is possible that, with further technical research and development, turbines may be developed that are able to accept variable hydrogen/methane blends.[80]

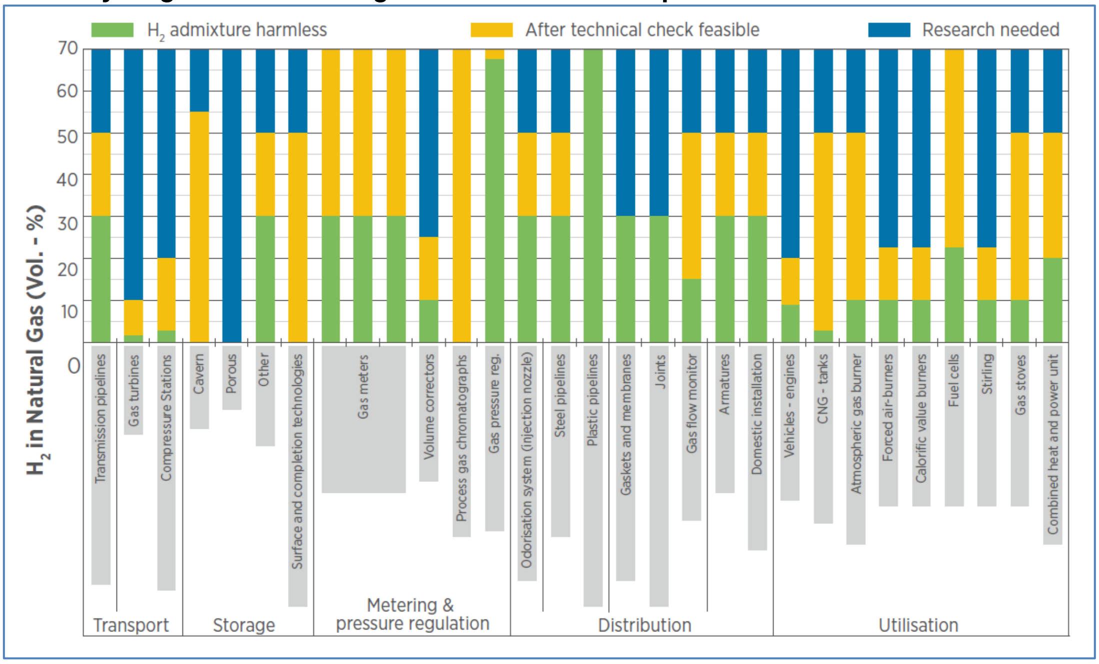
[76] For a comprehensive review of the engineering risks and uncertainties see 'Transitioning to Hydrogen' from the Institution of Engineering and Technology, 2019: https://www.theiet.org/media/4095/transitioning-to-hydrogen.pdf
[77] Shell (2017)
[78] IRENA, Hydrogen from Renewable Power, 2018: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Sep/IRENA_Hydrogen_from_renewable_power_2018.pdf
[79] https://www.ge.com/power/gas/fuel-capability/hydrogen-fueled-gas-turbines
[80] http://www.element-energy.co.uk/wordpress/wp-content/uploads/2019/11/Element-Energy-Hy-Impact-Series-Study-3-Hydrogen-for-Power-Generation.pdf

Figure 15: Ignition range of selected fuels



Source: Shell Hydrogen Study (2017)

Figure 16: Hydrogen tolerance of gas infrastructure component



Source: IRENA (2018)

The choice of 20 per cent blend level for the demonstration projects appears to have been made based on the acceptable level for the end-user equipment (typically boilers and other gas burners on the demonstration systems in question). As can be seen from Figure 15, it does not necessarily follow that a 20 per cent blend would be acceptable in all circumstances. Indeed the Hydeploy project in the UK was granted an exemption from the usual 0.1 per cent hydrogen limit by the UK Health and Safety Executive only after gathering and scrutinising extensive evidence.[81] In addition, it should be noted that,

[81] https://www.itm-power.com/news/hydeploy-uk-gas-grid-injection-of-hydrogen-in-full-operation

on account of the lower energy density of hydrogen compared with methane, a 20 per cent blend by volume equates to approximately only 7 per cent by energy content.

Nevertheless, with suitable checks and modifications, natural gas pipelines can be converted to 100 per cent hydrogen service. In November 2018, pipeline operator Gasunie started operation of a 12km former natural gas pipeline to carry up to 4000 tonnes (around 160 GWh) of hydrogen per year between Dow Benelux and Yara in the south of the Netherlands. This is the first time that an existing main gas transport line has been converted for hydrogen transport.[82]

The detailed H21 North of England study[83] in the UK, which expanded an earlier study of the city of Leeds, considered the possibility of converting 3.75 million meter points (each one effectively an individual domestic consumer) from natural gas to 100 per cent hydrogen. The study points out that this is comparable to the process between 1966 and 1977 when UK consumers were converted from manufactured gas to natural gas, which at peak converted over 2 million domestic consumers in one year. However, this comparison should be treated with some caution as it took place in a different regulatory era when British Gas was the monopoly supplier to all households and consumers were arguably more accepting of centrally imposed intrusion into their residences. In addition the safety considerations and required changes to end-user equipment are likely to be more significant for a conversion from methane to hydrogen than for the earlier conversion to methane. The H21 study had optimistically assumed that the conversion cost would be around £500 per appliance. A more detailed report commissioned by the UK government[84] highlighted that the issues involved in domestic conversion could be significant, including the need to investigate fully the integrity of behind the meter domestic gas pipework. The UK government is also backing the major Hy4Heat project which is aiming 'to establish if it is technically possible, safe, and convenient to replace natural gas (methane) with hydrogen in residential and commercial buildings and gas appliances'. This comprehensive piece of work is due for completion in 2021 and should provide a more accurate assessment of the feasibility and cost of potential hydrogen conversions. For transport of hydrogen the study assumed that existing gas distribution infrastructure, predominantly plastic pipes would be readily convertible to hydrogen, and assumed a total cost of only £143m for gas network conversion. On the other hand it envisaged that transmission between urban centres would require new-build hydrogen pipelines. As noted earlier, the H21 project has not progressed to the next stage of detailed engineering design, but the work to date already provides valuable insight into the challenges of converting a major city from natural gas to hydrogen. It is also clear that decarbonisation of space heating, whether by electricity or decarbonised gas will be both costly and challenging.

5. Discussion and conclusions

There are no easy or low-cost solutions to decarbonisation of the energy system and, as has been discussed in this paper, this is certainly the case for possible deployment of low-carbon hydrogen. A key challenge is to demonstrate the technical, commercial, economic and social acceptability of various possibilities at scale. Hydrogen will certainly play a role in decarbonisation of the energy system, although the size of the role may be more limited than envisaged in some more optimistic projections.

Industrial applications which currently use hydrogen clearly have potential to switch from their existing high carbon supply of hydrogen to lower carbon alternatives. While, in a decarbonising system, demand for hydrogen in oil refining is likely to decline, demand for hydrogen for manufacturing other products is likely to grow. In particular, ammonia manufacture is likely to increase along with demand for fertiliser, and possibly for use of ammonia as a marine fuel and as a means of transporting hydrogen.

[82] https://www.gasunie.nl/en/news/gasunie-hydrogen-pipeline-from-dow-to-yara-brought-into-operation
[83] https://www.h21.green/wp-content/uploads/2019/01/H21-NoE-PRINT-PDF-FINAL-1.pdf
[84] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/760508/hydrogen-logistics.pdf

Where feasible, taking into account both geological and stakeholder considerations, initial production of low carbon hydrogen is likely to be mainly by the addition of CCUS to existing hydrogen production facilities or construction of new methane reformers integrated with CCUS. Beyond a handful of demonstration projects, and those where CCUS is linked with a profitable application like enhanced oil recovery, it is unlikely that a commercial enterprise will voluntarily commit to the additional costs of CCUS. Similarly, production of hydrogen from electrolysis is currently higher cost than production from methane reforming with CCUS and so is also unlikely to happen at scale by companies acting alone. It will therefore be dependent on government policy to promote the required investments. Politically, individual countries may be reluctant to make the first move in such policies for fear of putting their manufacturing industry at a cost disadvantage relative to others. Ideally a global agreement (or at least an agreement among key industrial nations, like the G20) towards promoting low carbon hydrogen production for existing industrial applications could be a very good way to build experience of large scale manufacture of low-carbon hydrogen and hence drive down costs. OIES will consider regulatory aspects of decarbonisation in more detail in a future publication.

Once low-carbon hydrogen production has been established at scale, it could enable incremental addition of new applications, perhaps initially by expanding outwards from established industrial clusters (e.g. the Ruhr area in Germany, Tokyo/Yokohama in Japan, Humberside or Merseyside in UK and various industrial centres in USA). Such new applications are likely to include iron and steel production using DRI, and potentially other industrial applications requiring significant heat input, such as cement. Such clusters could also be the first locations to demonstrate decarbonised hydrogen use at scale for transport and other applications.

Beyond industrial applications, the next most promising is the use of hydrogen in transport in FCEVs for those, typically heavy duty, long distance, situations where BEVs are not feasible. Given the falling costs of BEVs and the much larger global fleet of BEVs compared to FCEVs, it is not possible to be definitive regarding situations where FCEVs will have an economic advantage over BEVs. There is certainly a risk that costs, range and charging time for BEVs will continue to fall to such an extent that FCEVs find that they can only play a small niche role.

Decarbonised hydrogen is also likely to have a role as a feedstock for the manufacture of other synthetic fuels for applications where other decarbonisation alternatives are not readily available, the most likely being:

a) synthetic methane, to supplement biomethane in existing gas grids and to reduce demand for fossil-derived natural gas;

b) ammonia, potentially for use in shipping;

c) synthetic aviation fuels.

Transport of hydrogen by pipeline is a well-established technology, and with detailed engineering work, conversion of existing natural gas pipelines to carry hydrogen is possible, and has been demonstrated. However, it cannot be assumed that it will be either straightforward or low-cost to convert large and complex natural gas systems to carry hydrogen. For this reason, it may prove more appropriate for most existing gas networks to continue to carry methane, albeit either biomethane or other non-fossil synthetic methane, and probably at lower volumes than is currently the case.

While there is not yet any clear pathway for decarbonisation of residential space heating in countries with high winter heating demand, it is likely to prove particularly challenging to convert a large number of small domestic consumers to hydrogen. Conversion to hydrogen of large industrial applications in a controlled environment is likely to prove much more feasible. Hydrogen is also very likely to play a role for long-term, high capacity storage of electrical energy, beyond the capability of batteries.

Costs of production and transport are likely to prove a significant challenge for hydrogen, particularly where there are other low carbon alternatives, notably renewable electricity, available. The cost and efficiency of the electrolysis process suggests that ‘green’ hydrogen will necessarily be significantly more expensive than electricity (€30/MWh electricity leading to a hydrogen cost in the range of €50-

60/MWh in the examples given in Section 3). In some circumstances, where it does not prove possible to build sufficient electrical transmission capacity, hydrogen may have a role in being able to transport energy over significant distances, although this is likely to add around €10/MWh per 1000km of pipeline transmission.

There remain many uncertainties around the future role of hydrogen in the decarbonising energy system, and it is certainly too early to say definitively that, 50 years after the term was invented, the world is moving towards a 'hydrogen economy'. There remains an urgent need for advocates of hydrogen to demonstrate the value chain at scale to increase confidence regarding key areas of technical feasibility, economics and consumer acceptance.