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The role of hydrogen and fuel cells in the global energy system

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Hydrogen technologies have experienced cycles of excessive expectations followed by disillusion. Nonetheless, a growing body of evidence suggests these technologies form an attractive option for the deep decarbonisation of global energy systems, and that recent improvements in their cost and performance point towards economic viability as well. This paper is a comprehensive review of the potential role that hydrogen could play in the provision of electricity, heat, industry, transport and energy storage in a low-carbon energy system, and an assessment of the status of hydrogen in being able to fulfil that potential. The picture that emerges is one of qualified promise: hydrogen is well established in certain niches such as forklift trucks, while mainstream applications are now forthcoming. Hydrogen vehicles are available commercially in several countries, and 225 000 fuel cell home heating systems have been sold. This represents a step change from the situation of only five years ago. This review shows that challenges around cost and performance remain, and considerable improvements are still required for hydrogen to become truly competitive. But such competitiveness in the medium-term future no longer seems an unrealistic prospect, which fully justifies the growing interest and policy support for these technologies around the world.

Broader context

Hydrogen and fuel cells have arguably suffered a 'lost decade' after high expectations in the 2000s failed to materialise. Three factors are enabling the sector to regain momentum. Firstly, improvements in technology and manufacturing mean that systems which cost \$60 000 in 2005 are now cost \$10 000. Secondly, commercial products are becoming widely available, and significant uptake is occurring in specific sectors such as Japanese microgeneration and US forklift trucks. Thirdly, a strengthened global resolve to mitigate climate change is coupled with increasing realisation that clean power alone is insufficient, due to the complexity of decarbonising heat and transport. This paper provides a comprehensive state-of-the-art update on hydrogen and fuel cells across transport, heat, industry, electricity generation and storage, spanning the technologies, economics, infrastructure requirements and government policies. It defines the many roles that these technologies can play in the near future, as a flexible and versatile complement to electricity, and in offering end-users more choice over how to decarbonise the energy services they rely on. While there are strong grounds for believing that hydrogen and fuel cells can experience a cost and performance trajectory similar to those of solar PV and batteries, several challenges must still be overcome for hydrogen and fuel cells to finally live up to their potential.

Introduction

Thirty years ago, hydrogen was identified as "a critical and indispensable element of a decarbonised, sustainable energy system" to provide secure, cost-effective and non-polluting energy.[1] Today, energy leaders see hydrogen as the lowest impact and least certain issue facing the global energy system.[2] "Hydrogen, as a viable alternative fuel, continues to promise much and deliver precious little".[3]

Yet hydrogen could play a significant role in low-carbon future:[4–8] counterbalancing electricity as a zero-carbon energy carrier that can be easily stored and transported;[9,10] enabling a more secure energy system with reduced fossil fuel dependence;[11,12] with the versatility to operate across the transport,[13,14] heat,[15,16] industry[17] and electricity sectors.[18,19] Together, these account for two-thirds of global CO_2 emissions (Fig. 1).

Whilst electricity is proving comparatively easy to decarbonise thanks to the dramatic cost reductions and uptake of renewables,[20] these other sectors must not be forgotten. In the UK for example,

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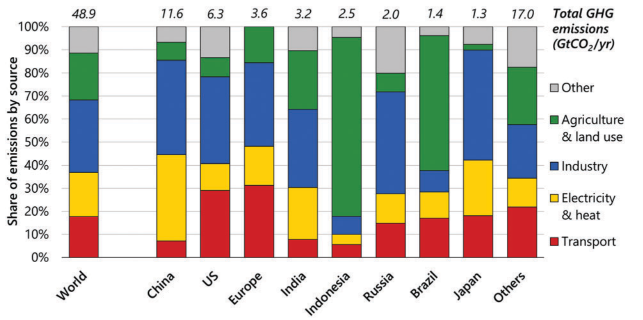

Fig. 1 Global greenhouse gas emissions in 2014, broken down by sector and by major countries. Data from CAIT.[23]

heat and transport are expected to decarbonise at just one-third the rate of electricity production, with emissions falling 24% compared to 68% over the coming 15 years.[21,22] Solutions are desperately needed to make transport and buildings sustainable that are cost-effective and appealing to consumers. Hydrogen and fuel cell technologies offer greater personal choice in the transition to a low-carbon economy, given their similar performance, operation and consumer experience to fossil-fuelled technologies. They also provide valuable insurance against the possibility of other vaunted technologies failing to deliver, such as carbon capture and storage, bioenergy and hybrid heat pumps.

Hydrogen and fuel cells are seeing a resurgence in interest: large-scale production of fuel cell vehicles has begun, and hundreds of thousands of homes are now heated and powered by fuel cells.[5] A key difference since the last hydrogen ''hype cycle''[24] in the 2000s is that manufacturing scale up and cost decreases mean hydrogen and fuel cells are being commercialised in several sectors, from portable electronics and backup power to fork-lift trucks.[25,26] Meanwhile, energy systems analyses have become more sophisticated in identifying the complexity of decarbonising heat and transport *via* full electrification, and thus the need for a flexible and storable energy vectors.[27–30]

Thirteen international corporations recently formed the Hydrogen Council ''to position hydrogen among the key solutions of the energy transition''.[6] Doing so involves challenges around its complexity and diversity:

(1) Hydrogen can be produced from many feedstocks and processes, with varying greenhouse gas and other emissions, costs and infrastructural requirements;

(2) Hydrogen can be used in many ways, including without fuel cells, whilst fuel cells can operate using fuels other than hydrogen;

(3) Hydrogen and fuel cells can contribute in many ways spanning the whole energy system;

(4) Hydrogen infrastructure may be costly, but pathways include several low-cost incremental routes that 'piggy-back' off established networks, which are often neglected.

In March 2017, the UK's Hydrogen and Fuel Cell Supergen Hub published a white paper that systematically assessed the current status and future prospects of hydrogen and fuel cells in future energy systems.[31] This article synthesises and updates that white paper, broadening its scope to a global focus. It builds upon previous holistic reviews of hydrogen and fuel cells,[32–34] and takes the novel approach of considering how they might be integrated together across the energy system.

This review covers the following:

• The transport sector, both personal vehicles and larger heavy-duty freight and public transit vehicles;

• Heat production for residential, commercial and industrial users;

• Electricity sector integration, balancing intermittent renewable energy;

• Infrastructure needs, options for using existing gas grids, compression and purity requirements; and

• Policy challenges, global support and targets for hydrogen and fuel cells.

Transportation

The suitability of hydrogen and fuel cells varies between transport modes and reflects the diverse nature of the transport sector, which spans land, sea and air, plus freight and passengers, as shown in Fig. 2. Nearly half of energy demand for global transport is from light duty vehicles and the number of passenger cars worldwide is expected to rise from 1 to 2.5 billion by 2050.[35]

The UK must halve its transport CO_2 emissions between 2015 and 2030 to meet national carbon budget commitments.[22] Emissions have increased though, and the share of renewable energy in UK transport has fallen to 4.2% *versus* a target of 10%,[36] bringing calls for stronger action.[37] Hydrogen represents one of three main options for low-carbon transport alongside biofuels and electric vehicles (EVs). Hydrogen avoids the land-use and air quality impacts of biofuels, and the limited range and long

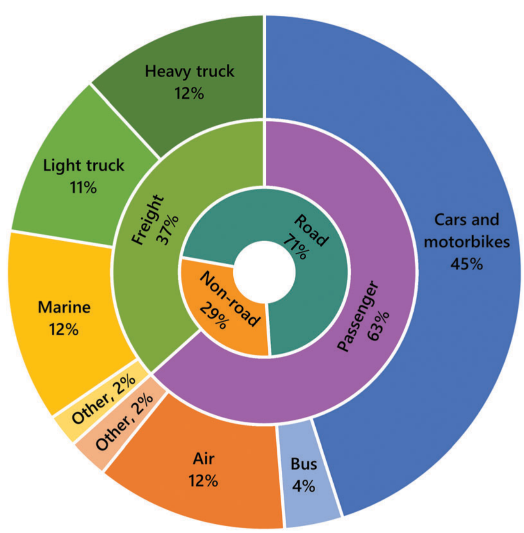

Fig. 2 Breakdown of energy usage in the transport sector globally in 2015. The outer ring gives the share of individual modes. ''Other'' is primarily passenger rail and air freight. The middle and inner rings aggregate these uses by mode and function. Data from EIA.[35] Total consumption was 110 million TJ in 2015 worldwide, equivalent to 37 kW h per person per day in OECD countries and 7 kW h in non-OECD countries.

recharging times associated with EVs.[5] However, electric cars are several years ahead of hydrogen in terms of maturity due to their lower costs and readily-available infrastructure. Plug-in electric vehicles now account for 30% of new vehicle sales in Norway and 2% in the UK.[38,39]

In addition to tackling climate change, hydrogen vehicles can improve air quality. This is an urgent priority with over half a million premature deaths per year across Europe due to particulates and NO_x emissions.[40,41] The direct cost of air pollution due to illness-induced loss of production, healthcare, crop yield loss and damage to buildings is around €24b per year across Europe with external costs estimated to be €330–940b per year.[42] 92% of the world's population are exposed to air quality levels that exceed World Health Organisation limits.[43,44] Major cities have recently announced bans on all diesel-powered cars and trucks by 2025,[45] and UK and France have announced nationwide bans on all pure combustion vehicles by 2040.[46,47]

Hydrogen powertrains

Conventional internal combustion engines can be modified to run on pure hydrogen ('HICEs') and could see early deployment as they are substantially cheaper than fuel cells. However, hydrogen combustion is less efficient than a fuel cell and releases NO_x, hence is not expected to play a significant long-term role in transport. Hydrogen can be blended with natural gas ('hythane') or diesel in dual-fuel vehicles; or it is possible to switch between both in bi-fuel powertrains. This allows the use of existing infrastructure, but these are not zero-emission and could eventually be displaced by lower-carbon options.[48]

Fuel cell electric vehicles (FCEVs) predominantly use PEM fuel cells, offering high efficiency, high power density and cold-start capabilities.[49] A 60 kW fuel cell is typical for European cars,[50] which is substantially larger than for residential fuel cells ($\sim$1 kW). Competing powertrains includes conventional internal combustion engines (ICEs), battery electric vehicles (BEVs) and plug-in hybrid vehicles (PHEVs, also known as range-extender EVs), which allow most journeys to be completed using a battery, and switch to the engine or fuel cell for less-frequent longer journeys.[51]

Hydrogen powertrains are compared to alternatives in Table 1, and differ in the following ways:[49,52]

(1) Capital cost: FCEVs have higher capital and operating cost than BEVs today: $60–75k for the Toyota Mirai or Hyundai ix35[53,54] *versus* $25–30k for the Renault Zoe or Nissan Leaf.[55,56] However, FCEVs have the potential for considerable cost reduction as manufacturing volumes rise, and could end up as cheaper alternatives.[5,50]

(2) Range and refuelling time: FCEVs have longer driving ranges and shorter refuelling times than BEVs, comparable to conventional vehicles (*ca.* 500 miles and 3 minutes).[49] The power-hungry computers and sensors in driverless cars will impact BEV range more than FCEV,[57] as does the air conditioning/heating for vehicles in hot/cold regions.

(3) Infrastructure requirements: hydrogen filling stations can serve substantially more vehicles than EV chargers, and a wider radius due to greater FCEV range.[58] Hydrogen refuellers are currently more expensive than electric charging posts: around $1.5m *versus* <$1000 for slow chargers,[4,59–61] although costs are expected to fall by two-thirds once the technology matures.[7,48]

Table 1 Comparative performance of primary drivetrains. Symbols give a qualitative comparison between different performance metrics (low/medium/high). Data from ref. 49

		ICE	FCEV	BEV
Lower is better	Current capital cost	$	$ $ $	$ $
	Fuel cost	$ $	$ $ $	$
	Maintenance costs	$ $ $	$	$
	Infrastructure needs	$	$ $ $	$ $
	Emissions	💧💧💧	💧	💧
Higher is better	Efficiency	*	* *	* * *
	Range	* * *	* * *	*
	Refuelling speed	* * *	* * *	*
	Lifetime	* * *	* * *	* *
	Acceleration	* *	* * *	* * *

(4) Lifetime: battery lifetimes are affected by local climate, overcharging, deep discharge and high charging/discharging rates;[62] Tesla expect batteries to last 10–15 years, yet most BEVs are <5 years old so such lifetimes are unproven.[51] In contrast to batteries, hydrogen tanks can undergo fast refilling and frequent, deep discharging without compromising lifetime, and fuel cell stacks are expected to outlive other drivetrain components.[63]

(5) User experience: FCEVs offer a smoother driving experience than ICEs (quieter, less vibration and no gear shifting).[64] However, hydrogen tanks are large and inconveniently shaped, potentially restricting luggage space.

(6) Emissions: FCEVs have zero emissions at point of use and are low-carbon at the point of production if made from renewable-powered electrolysis, biomass or fossil fuels with CCS. The same is true for BEVs, whereas there is limited decarbonisation potential for ICEs. Blending biofuels with petrol and diesel can reduce CO_2 emissions, but not improve local air quality.

(7) Network requirements: FCEVs and refuelling infrastructure can avoid the electricity network upgrades required for significant BEV penetration, and offer valuable grid-balancing services.

(8) Safety: FCEVs have comparable, but different, safety considerations to BEVs and ICEs. Hydrogen is flammable (more so than petrol) but hydrogen fires can cause little damage to the vehicle due to their localised nature.[49]

Passenger cars

Deep decarbonisation of transport must focus on private cars, which account for around half of the global transport sector (Fig. 2). FCEVs are currently expensive, but several analyses suggest cost reductions from mass-production could see their total cost of ownership (TCO) converging with other principal powertrains by 2030 (Fig. 3).[4,7,13,50,65,66]

Platinum is a key contributor to capital cost, as mid-sized fuel cell vehicles require ten times more (*circa* 30 g) than a

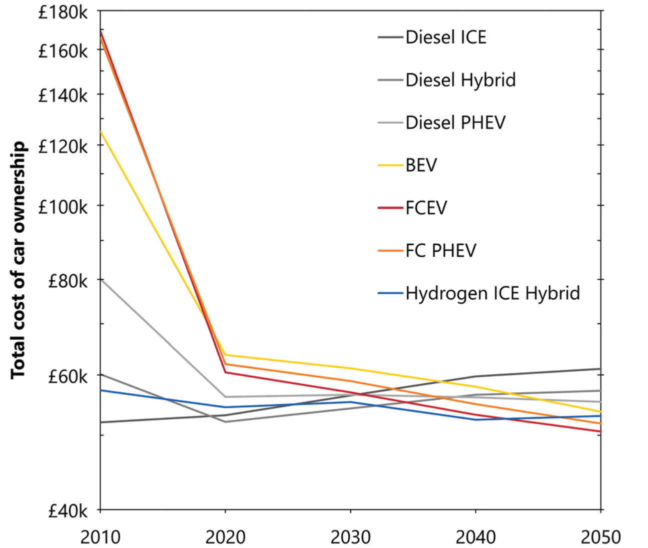

Fig. 3 Total cost of ownership for major powertrains from ref. 50. Hydrogen, electric and fossil-fuelled vehicle lifetime costs are expected to converge by 2030.

diesel autocatalyst.[67] Strong progress has been made on reducing platinum content: Daimler cut 90% since 2009 and Toyota target a 50% reduction from current levels,[68] which will prove essential for volume scale-up.[67]

Passenger FCEVs are believed to require production volumes of around 100 000 units per year (and hence considerable financial support) to approach cost parity. With global passenger car sales of ~70 million per year, this small penetration represents a sizeable market.[69] If cost parity is achieved, other key aspects relating to user experience may make FCEVs favourable: 78% of automotive executives believe faster refuelling will make FCEVs the breakthrough for electric mobility, whilst BEV recharging times will remain an insuperable obstacle to acceptance.[70]

Deployment could be accelerated by targeting powertrain configurations with smaller initial hurdles. These include range-extender EVs (FC RE-EVs), where smaller stacks (<20 kW) and lower fuel consumption mean FC RE-EVs can be competitive at smaller volumes.[7]

Toyota, Hyundai and Honda now produce FCEV passenger vehicles, with Audi, Mercedes-Benz and others expected to follow suit.[71,72] Whilst FCEVs are offered in only a few countries due to infrastructure requirements, around 3000 FCEVs have been sold to date (see Policy challenges section). Deployment is expected to accelerate, with the Hydrogen Council pledging to invest $1.75 billion p.a.[73] The majority of automobile executives identified FCEVs as the most important trend up to 2025.[70] Longer term, the IEA concludes that FCEV sales could reach 8 million by 2030 in developed nations, and 150 million sales and a 25% share of road transport by 2050.[4]

Refuelling stations

A complication for passenger vehicles is the need for extensive expansion of refuelling infrastructure to offer the reach and freedom of conventional vehicles.[58] Battery electric vehicles face this to a lesser extent due to the lower cost of electric chargers: the UK has rapidly developed 5000 electric charging locations to rival its 8500 petrol stations, compared to just 15 hydrogen stations[74,75] While 15 hydrogen dispensers could deliver comparable throughput to 900 BEV fast-chargers, they do not offer the same geographic coverage and convenience.

Globally, there are 330 hydrogen refilling stations as of 2018, half of which are in Japan and the US[76] (Fig. 4). The various European H2Mobility programs have suggested a rollout of refuelling stations at critical locations, with a network of 65 refuelling stations for the UK by 2020 to start the market, growing to 1150 stations by 2030 to cover the whole country.[77] The Hydrogen Council targets 3000 refilling stations globally by 2025, sufficient to provide hydrogen for about 2 million FCEVs, after which refuelling infrastructure should be self-sustaining.[66] National roadmaps only target around half this number though (see Section 6.1).

Return-to-base fleets such as delivery vans and taxis, or passenger cars in a future car-sharing economy will see high utilisation and benefit from single refuelling depots with fast, infrequent refuelling. The requirement for less infrastructure could enable distribution costs to fall more rapidly than in the passenger FCEV sector, suggesting deployment in these sectors should be targeted.[7] Urban taxis are another promising

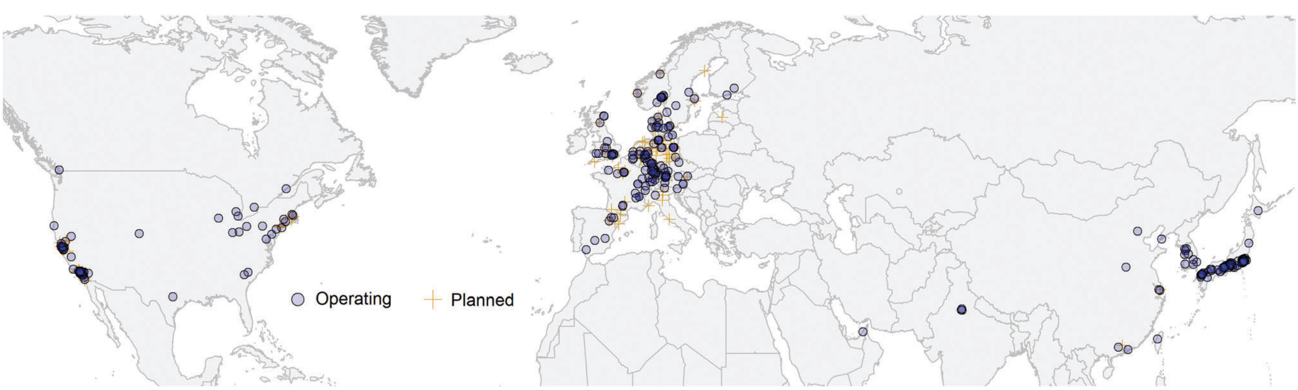

Fig. 4 Map of the hydrogen filling stations currently in operation and planned. The map focusses on the existing stations in the northern hemisphere, a further 8 stations are not plotted. Data from www.h2stations.org by LBST and TÜV SÜD.[76]

early market: new London taxis must be zero emission capable from 2018,[78] and Paris will purchase 60 new FCEV taxis with plans for hundreds more.[79]

Other road transport

Whilst FCEVs face strong competition from ICE and BEV passenger cars, they may be the best (and perhaps the only) realistic zero-carbon option for high-utilisation, heavy-duty road transport vehicles such as buses and trucks. These are significant sectors, accounting for a quarter of transport energy usage (Fig. 2 earlier). Growing calls to minimise urban air and noise pollution are major drivers for hydrogen bus rollout.[64] Back-to-base operation means fewer refuelling stations are needed and are more highly utilised, reducing initial refuelling costs.

Three key differences for heavy-duty transport are low manufacturing volumes (meaning the cost gap with ICE is smaller), and the need for greater longevity and energy density. The US DOE targets 25 000 hour operating lifetime for fuel cell buses, *versus* just 8000 for passenger cars.[80,81] Greater vehicle weight and driving range mean battery technologies are likely to remain unsuitable outside of urban environments; for example, fuel cell buses consume 10 times more hydrogen per kilometre than passenger cars – amplifying range limitations.[82,83]

Fuel cell buses. Fuel cell buses in particular have attracted significant attention and are relatively mature, at Technology Readiness Level (TRL) 7.[84] On-board tanks typically hold around 40 kg of hydrogen stored in the bus roof,[48] and reduced space restrictions mean this can be stored at 350 bar, reducing tank and compression costs. Fuel cell buses may have a 10–20% higher total cost of ownership (TCO) than diesel by 2030, and could be cheaper if deployed at scale.[85]

Fuel cell buses have seen substantial early deployment, with 7 million kilometres of operational experience so far in Europe.[86] Europe has 83 operating fuel cell buses, with 44 in North America.[87,88] Toyota is planning to introduce over 100 fuel cell buses before the Tokyo 2020 Olympic Games.[89] China has the world's largest bus market,[90] with 300 fuel cell buses ordered for Foshan City (quadrupling the global fleet of hydrogen powered buses).[91] For context, Shenzhen City has electrified its entire fleet of over 16 000 buses using BEVs.[92,93]

Good progress is being made with longevity, with four London buses operating more than 18 000 hours.[87] Ten buses in California have passed 12 000 hours of operation with one reaching 22 400 hours: close to the DOE's ultimate target of 25 000 hours.[80,82] Fuel cell bus availability has exceeded 90% in Europe (*versus* an 85% target), with refuelling station availability averaging 95%.[87]

Trucks. Trucks show considerable potential for fuel cell adoption as high energy requirements mean few low-emission alternatives exist. Light goods vehicles with short low-speed journeys could be managed with batteries and range-extender vehicles;[48] however, long-haul heavy vehicles which require high utilisation are likely to require hydrogen. Competition from batteries is nonetheless increasing, with the Tesla Semi expected to offer 300–500 mile range for ~\$200 000.[94] Cost parity of fuel cell trucks with other low-carbon alternatives could be achieved with relatively low manufacturing volumes.[7] Return-to-base delivery vehicles could see lower fuel costs with a single refuelling depot, although long-range HGVs need an adequate refuelling network.

Higher longevity is required than for other applications due to the high mileage expected of trucks, with one program targeting 50 000 hour stack lifetime.[48] High efficiency and low fuel costs are also essential.[4] Kenworth and Toyota are considering hydrogen truck production,[95,96] and Nikola is also developing a long-distance HGV using liquefied hydrogen in the US.[97] Fuel cells are also being developed as Auxiliary Power Units (APUs) for HGVs.[48] These could power refrigeration units and 'hotel' loads on stationary HGVs (*e.g.* cabin heating, cooling, lighting, and electrical devices) to avoid engine idling.[98]

FCEV trucks have seen lower adoption than buses due to the HGV market being highly cost sensitive with limited government support or intervention, and highly conservative with hauliers wary of being pioneers.[48] However, Anheuser-Busch InBev (an international drinks company), recently ordered 800 FCEV trucks to be in operation in 2020.[99] Interest could grow as diesel trucks begin to be banned from major city centres.[45]

Motorbikes. Two-wheeled vehicles are dominant for passenger transport in many regions. Intelligent Energy has developed a 4 kW fuel cell system in cooperation with Suzuki,[48] now being trialled in the UK.[100] Their low fuel consumption allows them to be refuelled using hydrogen canisters from vending machines. FCEV motorbikes could contribute toward air quality and noise pollution targets.

Off-road transport

Trains. Electrification can replace diesel trains but progress has slowed recently across Europe.[48] Hydrogen trains could be used on routes which are difficult or uneconomic to electrify due to route length or lack of space in urban areas. A fuel-cell powered train with roof-mounted hydrogen tanks and a range of 500 miles has begun testing in Germany,[101] and 40 trains could be in service by 2020.[102] Alstom announced plans to convert a fleet of trains in the UK from electric to hydrogen to negate the need for line electrification and meet the government target of eliminating diesel trains by 2040.[103]

Light rail also presents opportunities for hydrogen, with fuel cell-powered trams being developed and operated in China.[7,104] Low volumes mean that hydrogen trains are expected to use the same stacks and storage tanks as buses and trucks, so cost reductions will be consolidated with the automotive sector. Hydrogen powertrains may be 50% more expensive than diesel, but economic viability will depend on lower-cost fuel, and hydrogen costing under \$7 per kg.[7] One study concludes that FCEV trains are already cost competitive with diesel trains from a TCO perspective.[66]

Ships. Marine applications hold promise for hydrogen deployment, with fuel cells already being trialled for propulsion in a handful of projects including ferries.[7,48,105] Hydrogen is not expected to gain traction until after 2030, although the growth of emissions controlled zones (such as the Baltic Sea and urban ports) and hydrogen's higher efficiency than LNG could drive early niches.[48] Most vessels have long lifetimes, are built in small numbers highly tailored to specific applications; this could hamper the rollout of new propulsion systems.[7] With ferries potentially consuming 2000 kg of hydrogen per day, cryogenic storage is necessary, and fuel costs are more important than upfront capital, with hydrogen significantly below $7 per kg needed.[7,106] Fuel cells for auxiliary power could be adopted earlier than for propulsion,[48] and port vehicles could also be early adopters, improving local air quality with a single refuelling depot.

Aeroplanes. Aviation is one of the hardest sectors to decarbonise, and reducing emissions from aircraft propulsion has seen little progress. In 2016 the International Civil Aviation Organization agreed to cap aviation emissions at 2020 levels, but primarily through carbon offsetting rather than low-emission fuels.[107] Some hybrid electric concepts are being studied, though emission reductions will be limited.[108] Biofuels could be suitable due to their higher energy density than hydrogen or batteries, but are not completely emission-free and could remain costly with limited availability. Hydrogen could be used as a propulsion fuel, but needs to be liquefied to supply the required range. Combustion turbines are likely to be needed as fuel cells lack the power required for take-off. However the climate benefits of hydrogen for aviation have been questioned because it produces more than double the water vapour emissions of kerosene; water vapour at high altitudes, although short lived in the atmosphere, causes radiative forcing and thus contributes to net warming.[109] Significant hydrogen deployment is thought unlikely before 2050 except perhaps for small or low-flying aircraft.[48] Hence much work remains on developing options for low-emission aircraft propulsion.

Other aviation-based sectors are more promising. Fuel cells have been tested for aircraft auxiliary power units and for taxiing aircraft to/from airport terminals.[110] There is an increasing motivation to improve air quality around airports and fuel cells could play an important role in powering ground vehicles and buses in the next 10 to 20 years,[48] aided by the need for a low number of refuelling stations experiencing high utilisation. Unmanned aerial vehicles (UAVs) are also attracting considerable interest for both civilian and military applications.[7] Fuel cell UAVs are quieter, more efficient, and have lower vibration and infrared signatures than fossil fuel-powered UAVs, and are lighter than battery systems, offering longer range. Fuel cell UAVs are currently considerably more expensive than battery UAVs; but the cost gap will close with manufacturing volume, and fuel cells retain the advantage in long-duration or high energy applications.[7]

Forklift trucks and others. Other promising applications include forklift trucks, with around 12 000 fuel cell units deployed in the US and a handful elsewhere.[111] Plug Power supplies 85% of FC forklifts in the US.[112] The zero emissions from FC forklifts allow them to operate indoors, and their faster refuelling than batteries can lead to TCO savings of 24% in a typical high throughput warehouse.[113] FC forklifts also have a wide temperature range, capable of operating in temperatures as low as −40 °C. PEMFCs are most widely used with longer lifetimes, but direct methanol fuel cells (DMFCs) are also found in lower usage applications with shorter lifetimes and lower cost of ownership.[112] Fuel cells could also see adoption in agricultural equipment such as tractors[114] and recreational applications such as caravan APUs and golf carts, one of the few sectors that are proving profitable.[90]

Heat and industry

Heat and hot water accounts for 60–80% of final energy consumption in residential and commercial buildings across Europe.[115,116] Emissions from heating need to be reduced rapidly and largely eliminated by 2050; however, the heat sector is proving hard to decarbonise for several reasons:[117,118]

(1) Heating is the largest energy demand in many temperate countries and presents a problem of scale;

(2) Requirements are diverse, ranging from dispersed low temperature space heating to large high-temperature industrial loads, with no one solution capable of meeting all heat demands;

(3) Heat demand varies daily and seasonally, requiring highly flexible supply;[119]

(4) Fossil heating fuels provide this flexibility at a lower cost than low-carbon alternatives less competitive and risk increasing energy poverty.[120]

A particular challenge for low-emission heating in temperate countries is meeting winter peak heat demand,[121–123] which is considerably higher and more variable than peak electricity demand (Fig. 5 and 6). This strong seasonal variation is easily met by prevailing gas heating technologies, as low per-kW capital cost means they are routinely oversized for buildings,[119] and the gas network (including geological storage) can store a month's worth of consumption.[122]

Improved insulation, residential or communal thermal storage, and more efficient conversion devices could reduce peak requirements, but require strong regulation which has not been forthcoming.[122] Alternative low carbon options such as electrification or district heating could meet peak heat demand, but large infrastructural investment would be required, and a decarbonised gas-based approach may be more cost-effective.

Hence progress in decarbonising heating has lagged severely behind other sectors. For example, the UK relies heavily on

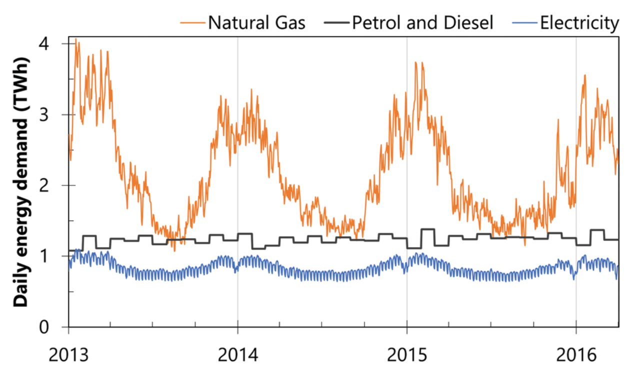

Fig. 5 Demand for the major energy vectors in Britain.[124]

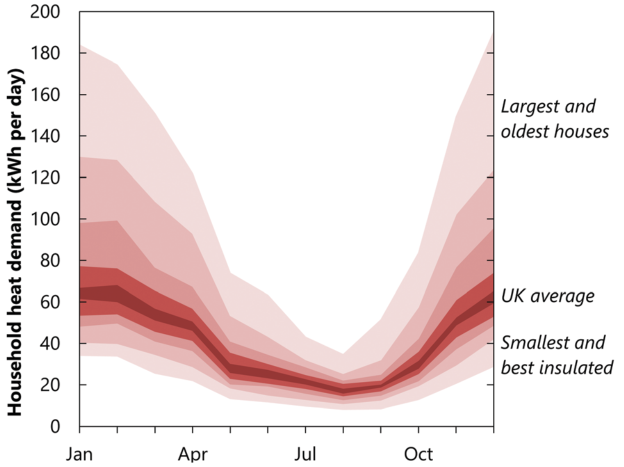

Fig. 6 Variation in British household heat demand between classes of housing for an average year. Heat demand includes space and water heating. Consumption is strongly temperature-dependent and winter peaks can be much higher in a cold year.[123]

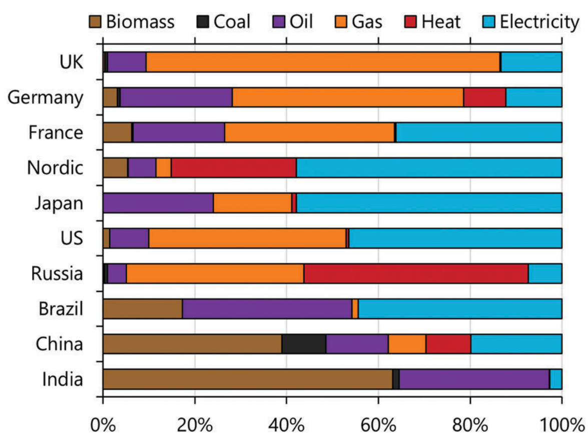

Fig. 7 The share of fuels used for domestic heating in ten countries, estimated using the DESSTINEE model[132] with data from the IEA.[134] Biomass includes both traditional (wood, dung) and modern (wood and miscanthus products); heat is generated off-site and sold to users; electricity includes both traditional (resistance and night-storage heaters) and modern (heat pumps).

natural gas and is likely to miss its 2020 target for renewable heat.[36,125] It may only achieve emission reductions from buildings and industry of around 20% by 2030, compared to an overall target of 57%.[22] Natural gas is currently a cheap, convenient and relatively clean alternative to coal and oil, and is the dominant fuel for heating in many counties, as shown in Fig. 7. Electric heat pumps are well established in Asia, America and parts of Europe, with over a billion systems heating homes;[126] whilst district heating is widely used in Russia and Scandinavia.[127]

Options for low-carbon heat

Five main options have been proposed for decarbonising heat globally,[122,128–131] as summarised in Table 2 and below. Most of these have gained traction in specific countries, but none are widely used on a global scale. The main options are:

(1) Demand reduction. Insulation, higher efficiency devices and changing demand behaviour (*e.g. via* smart meters and pricing) can all reduce heating energy demand. Residential heat consumption could fall 20% by 2050,[122] which is a valuable contribution and an enabler for other low-carbon heating technologies, but insufficient in isolation. Barriers to greater reduction include 80–90% of the 2050 housing stock having already been built in developed countries;[125] some properties being unsuitable for retrofitted insulation; and household size (people per building) shrinking due to lifestyle choices.[132]

(2) Green gas. Natural gas could be replaced by a low-carbon gases, utilising the existing gas network assets and potentially reducing costs and disruption.[133] Biogases can be generated by anaerobic digestion or gasification of waste, sewage, landfill gas, energy crops, *etc.* However, barriers to large-scale delivery include: resource availability and priority (it could be used in various energy/product routes); emission reduction potential; local emissions; and gas quality. The UK Bioenergy Strategy therefore limits heating uptake to 15%.[122] An alternative is hydrogen, which can be injected into the existing gas network in small quantities, or the existing gas network can be converted to distribute 100% hydrogen rather than natural gas (Section 5.4).

(3) Electrification. Heat pumps are widely used in many countries, and globally could deliver an 8% reduction in CO_2 emissions if widely adopted.[126] However, their low-grade heat and limited output may not meet peak winter demand and consumer preferences, and high uptake may force electricity network upgrades.[29] High upfront costs restrict uptake, although these might fall as rollout progresses. Nevertheless, heat pumps may play an important role, particularly for rural homes too remote for district heating or gas networks, which use expensive high carbon fuels such as heating oil, and with space for larger systems.[133] Electric heating is also well suited to high density urban housing blocks where gas is not allowed for fire safety, and space heating requirements are lower.[133]

(4) Heat networks. District heating is only commonplace in a handful of countries, which typically combine a cold climate with an acceptance of collective solutions. It has the potential to provide 10–20% of residential heat by 2050 in densely populated countries such as the UK.[122,135] Retrofitted heat networks are capital-intensive and disruptive to install, and heat losses limit transmission distances to around 30 km.[136] They are best suited to urban new-build, but offer 30% lower heating costs than gas boilers.[121] They can use geothermal heat or waste heat from industry and data centres. Large district heating CHP schemes are cheaper and more efficient than individual residential systems.

(5) Onsite renewables. Modern renewable energy produces 9% of the world's heat, nine-tenths of which is biomass, and the remainder solar thermal and geothermal.[20] However, there are concerns over the limited availability and high localised emissions of biomass, poor matching between solar thermal production and demand,[122,137] and cost and performance penalties of small-scale residential systems.[138]

Each low carbon heating technology exhibits barriers or uncertainties associated with technical feasibility, cost, suitability

Table 2 Summary of the decarbonisation options for heat

	Advantages	Disadvantages
Demand reduction	+ Insulation and more efficient devices raise consumer awareness + Reduction to energy bills + Low-regret option	− Low turnover rate of building stock − Difficulty retrofitting existing buildings − Consumer indifference/apathy
Green gas	+ High customer satisfaction/familiarity + Low cost for gas appliances + Easily meets peak demand + Low conversion cost and disruption	− Gas is difficult to decarbonise − Limited availability and need for cleaning − Hydrogen networks unproven, with uncertain availability, costs and safety implications
Electrification	+ Proven and widely used in many countries + Benefits from further decarbonisation of electricity systems + Well suited to countries with mild winters + Good option for remote rural properties not on gas or heat networks	− Could necessitate power system upgrades − Difficulty meeting peak demand without greater building thermal efficiency. − Higher cost, higher space requirements − May require heat storage − Performance sensitive to installation quality
Heat networks	+ Proven and widely used in some countries + Could meet ∼10–20% of UK heating needs + Good option for new-builds and densely-populated regions	− High conversion cost and disruption − Heat cannot be transported long distances − Needs low-carbon heat sources − User scepticism
Onsite renewables	+ Use local energy sources + Reduces network dependence and upgrade requirements	− Small schemes less cost-effective − Limited availability and high emissions (biomass) − Poor match to demand (solar thermal)

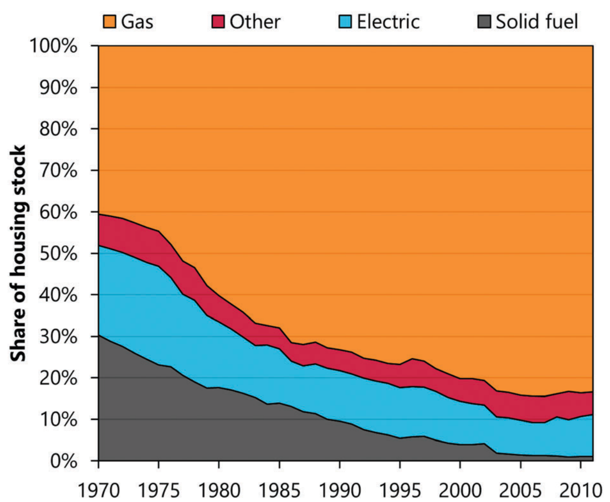

Fig. 8 The mix of heating technologies used in UK households over forty years.[141]

across regions and building types, user acceptance and safety. Individual countries are often dominated by a single technology. The UK has an 84% penetration of gas, although this is a recent development (Fig. 8). In the US, 97% of new family homes are either heated by natural gas or electricity.[139] Previous studies have therefore focussed on widespread rollout of a single technology to meet decarbonisation needs.[140]

However, a portfolio of complementary heating technologies used to be more prevalent, and is now regaining recognition.[123] For example fuel cell CHP systems can export electricity to the grid at the same time as heat pumps consume it; a UK case study found that a 50% penetration of fuel cell micro-CHP could completely offset the electrical demand from a 20% penetration of heat pumps.[123] The UK recognises the lack of consensus on the optimal technology mix to deliver the required long-term changes, and the need to thoroughly re-assess the evidence and test different approaches.[121] This technology mix could vary according to regional availability and building type and provide a hedge against uncertainties over technology feasibility and fuel price.

Hydrogen and fuel cell technologies

Until recently, most energy systems and building stock models did not include hydrogen and fuel cell technologies for meeting decarbonisation targets.[123] However, recent studies have identified hydrogen as having an important role in decarbonising heat,[122,142] able to provide the majority of UK heat demand by 2050.[48] There are several H2FC technologies to deliver heating.

Hydrogen boilers. Existing gas boilers and furnaces can run on hydrogen mixtures at low levels (see Section 5.4). Although high concentrations have a similar Wobbe index to natural gas, different burner tips are required due to hydrogen's higher flame speed.[143] Catalytic boilers are also under development, which eliminate NOx formation[48] but are less powerful and require higher purity hydrogen.[144] Consequently, a changeover to hydrogen would require wholesale refitting of either appliances or components within appliances. Such a wholesale refitting of appliances is not unprecedented: many countries have switched from town gas to natural gas in recent decades, with the UK replacing 40 million appliances, at a cost of £8b in 2015 money, over an 11 year conversion programme.[144]

Fuel cell CHP. Combined heat and power (CHP) systems co-produce electricity and heat at high efficiencies *via* engines or

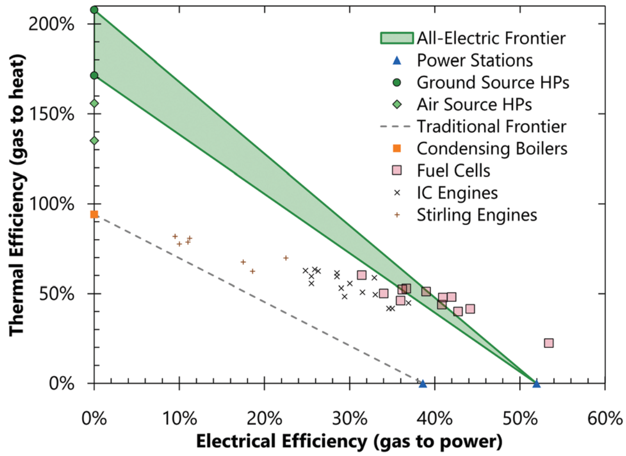

Fig. 9 Thermal and electrical efficiencies of CHP devices.[145] The 'thermal efficiency' of heat pumps is their coefficient of performance (COP)[126] multiplied by the efficiency of power generation.

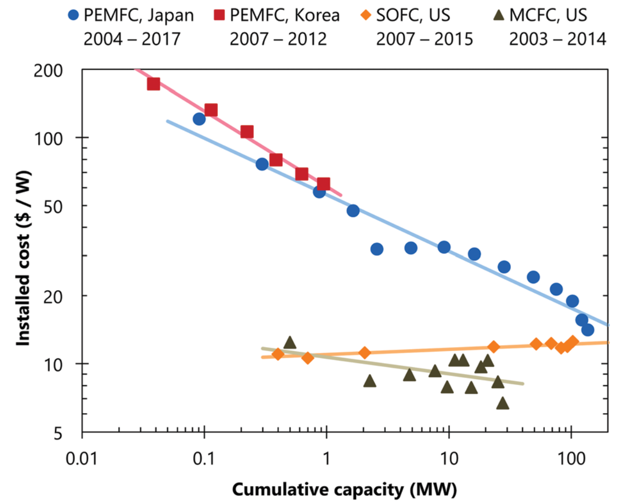

Fig. 10 Learning curves fitted to historic prices of Japanese and Korean residential PEMFCs,[147,155,156] American SOFCs and MCFCs.[157,158] The year for the first and last data point in each series is shown. Each doubling in production has seen prices fall by 16% for EneFarm in Japan; by 21% for Korean residential PEM generators; by 5% for 250 kW-class MCFCs in the US; and increase by 2% for 200 kW-class SOFCs in the US.

fuel cells and may use a variety of fuels.[32] The balance between electrical and thermal generation varies between technologies (Fig. 9). Combustion devices (IC engines and Stirling engines) generate more heat than electricity so are better suited to large buildings with high heat loads, but release particulates and NO_x.[146]

All CHP technologies offer greater combined efficiency than the 'traditional frontier' of using average power stations and condensing gas boilers. Only fuel cell CHP can exceed the efficiency of the 'all-electric frontier' of using the best combined-cycle gas power stations with the best ground-source heat pumps.[145] Fuel cell CHP systems have higher electrical efficiency and lower emissions (Table 3) than other CHP. PEMFCs and SOFCs are typically used for domestic systems, and SOFCs, PAFCs and MCFCs for larger commercial systems.[123] Given their higher power-to-heat ratio, fuel cells are more suitable for well-insulated buildings with lower heat loads. FC-CHPs are currently expensive, but costs have halved in the last six years and lifetimes have grown with increasing rollout in Japan and also more recently in Europe.[147] Existing CHP systems mostly operate on natural gas, but could switch to hydrogen if available with little modification (or even simplification).

Fig. 10 visualises how prices are falling with increased uptake for some technologies (residential PEMFCs in Asia), but have stagnated for others (large MCFC and SOFCs in the US). Prices are converging at around $10 000 per kW; a price point which solar PV modules reached in 1990.[148] Other issues such as product lifetime and reliability have improved significantly, to the extent that a fuel cell CHP unit is now equivalent in both these respects to a modern gas-fired boiler.[149–154]

Other technologies. Other heat technology options include gas-driven heat pumps (GDHPs), where the heat pump is powered by an engine, which could run on hydrogen. GDHPs currently achieve energy savings of 26–43% compared to condensing boilers, and avoid upstream complications from increased electricity demand.[122]

Tens of thousands of non-residential GDHPs have been sold across Europe and Asia; costs are currently high, but should come down significantly.[122,123] Hybrid heat pumps are another option, with electric heat pumps providing the majority (60–95%) of a building's annual heat demand, but with a gas boiler retained for meeting peak demand.[122] Several studies have identified hybrid heat pumps as suitable for many buildings in 2050;[48,122,123] though such systems require additional capital

Table 3 At-a-glance summary of fuel cell CHP performance[145,161]

		PEMFC	SOFC	PAFC	MCFC
Application		Res	Res/Com	Com	Com
Electrical capacity	(kW)	0.75–2	0.75–250	100–400	300+
Thermal capacity	(kW)	0.75–2	0.75–250	110–450	450+
Electrical efficiency[a]	(LHV)	35–39%	45–60%	42%	47%
Thermal efficiency[a]	(LHV)	55%	30–45%	48%	43%
Expected lifetime	('000 hours) (years)	60–80	20–90	80–130	20
		10	3–10	15–20[c]	10[c]
Degradation rate[b]	(per year)	1%	1–2.5%	0.5%	1.5%

Res: residential. Com: commercial. [a] Rated specifications when new. [b] Loss of peak power and efficiency. [c] Requires an overhaul of the fuel cell stack half-way through the operating lifetime.

expenditure and connection to both electric and gas networks. Wall-mounted fires are waning in popularity, but several hydrogen-powered fireplaces have been designed.[144]

There is considerable scope for hydrogen usage as a cooking fuel, with burners and barbecues under development today.[123] Hydrogen for cooking will need food-safe odorants and colourants, and will alter cooking times as hydrogen produces about 60% more water vapour than natural gas when burnt.[144]

Residential and commercial heating

Residential fuel cells have seen significant uptake, and now have the largest market share for micro-CHP systems,[7] with over 225 000 systems installed globally (see Section 6.1). PEMFCs are the dominant technology with high efficiency, durability, reliability, rapid start-up and shut-down, part-load capability and operating temperatures of around 80 °C.[32,123] Their electrical efficiency is lower than other fuel cells (~35%), but with higher thermal efficiencies (55%).[147] Their low-temperature heat output makes them suitable for individual buildings. About 7% of Japan's systems are SOFCs,[159] which tend to run constantly as start-up and shut-down times can exceed 12 hours.[123] They have higher electrical efficiency (~40–60%), greater fuel flexibility, reduced purity requirements, reduced catalyst costs due to higher operating temperatures, and higher temperature heat which is more suitable for existing building stock with smaller radiators.[7]

The cost of residential systems is dominated by capital and stack replacement costs, with small systems used to maximise utilisation.[48] Fuel cell micro-CHP could be cost competitive with other heating technologies between 2025–2050,[123,160] with fuel costs becoming dominant. Larger multi-family home and commercial units (2–20 kW_e) could be competitive at smaller production volumes, but have a smaller market.[7]

CHP systems are also popular in the commercial sector, with 100s of MWs installed globally, primarily in the US and South Korea.[7] MCFC and PAFC fuel cells dominate commercial systems with stable operation, cheaper catalysts and high efficiencies, although their complex subsystems do not scale down well for smaller applications (*e.g.* needing to remain heated whilst off to prevent electrolyte freezing). MCFCs have higher electrical efficiencies (>50%) with correspondingly lower heat production; however, they are inflexible with short lifetimes (20 000 hours) and high degradation rates due to corrosive electrolytes (Table 3). Their reliance on carbon dioxide for fundamental electrode reactions also make them unsuitable for operating on hydrogen,[48] but opens up new possibilities for carbon capture and storage.[162] PAFCs have a lower electrical efficiency than MCFCs but a higher thermal and overall efficiency (Table 3). They last longer (80 000–130 000 hours) with lower degradation rates and are more flexible, giving scope for load-following capability.[7] PAFCs could potentially be cost-competitive with ICE-CHP by 2025 at relatively low production levels of 100 units per year.[7]

FC-CHP systems are quiet and low-emission making them ideal for urban areas.[120] Fuel costs are a major component of the Total Cost of Ownership (TCO), driving improvements in efficiency.[7] PEMFC and SOFC also see some uptake in commercial applications.

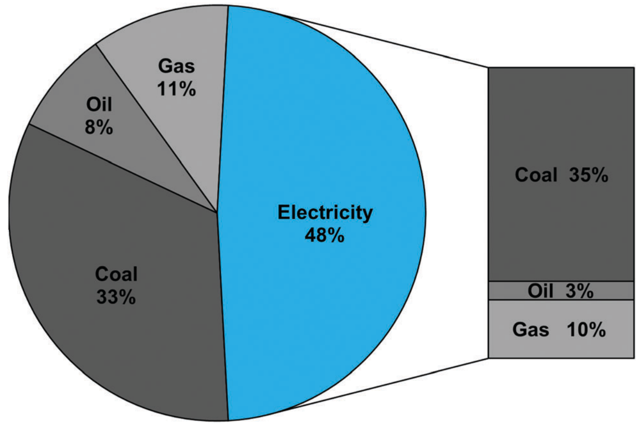

Fig. 11 Carbon emissions from industry, broken down by fuel. Global emissions (including those from electricity production) were 12 $GtCO_2$ in 2014, 37% of the global total. Data from ref. 163.

Industry

Industry relies on fossil fuels for three-quarters of its fuel mix,[23] and accounts for one fifth of direct global greenhouse gas emissions (see Fig. 11), with very little progress on decarbonisation to date. Hence low-carbon options for industry need to be identified urgently; options identified to date include CCS, biomass as a fuel, electrification, energy efficiency and heat recovery, industrial clustering and switching to hydrogen – noting it can be both a fuel and feedstock.[7] Long equipment lifetime and investment cycles in conservative sectors mean change will be slow.

Hydrogen is already widely used in industry as a chemical feedstock (*e.g.* in ammonia production and oil refining) and produced as a by-product in chemical manufacturing processes (*e.g.* chlorine), rather than as an energy vector.[123,136]

Hydrogen could replace natural gas as a fuel for providing heat and power in a number of industries; burners and furnaces may need replacement, but would not require high purity. Hydrogen could also be introduced into several high-temperature industries including steelmaking and cement, although commercialisation is not expected before 2030 due to low maturity, uncertain costs, the likelihood of needing fundamentally re-designed plant and the slow turnover of existing systems.[7,48] Industry requires cost-effective and reliable systems, with purchasing decisions based primarily on technical performance and economic rationality; space constraints and aesthetic concerns can be largely ignored.[123]

The power system

Global electricity consumption has doubled since 1990 and represents 40% of primary energy demand.[134,164] Fossil fuels produce two-thirds of global electricity, emitting 15 $GtCO_2$ each year, or 42% of the global total.[165] National roadmaps[22,166] and international modelling studies[128,167,168] agree that electricity should be rapidly decarbonised during the 2020s and then push forwards the decarbonisation of transport and heating through electrification.

Unlike other sectors, electricity generation has available a range of low-, zero- and even negative-carbon alternatives already available. The IPCC recommends that low-carbon generation rise from around 30% of total generation today to over 80% by 2050.[169] This radical shift appears feasible: Fig. 12a shows that wind and solar power have seen ten-fold growth over the last decade to total 665 GW: 11% of global generating capacity.[164]

Wind and solar power are forms of intermittent renewable energy: their output cannot be fully controlled or predicted as they rely upon the weather. Balancing supply and demand requires new solutions if electricity systems are to fully decarbonise whilst maintaining current levels of cost and reliability. Electricity has the fundamental constraint that supply must always balance demand,[170] and system reliability is paramount as outages cause severe economic and social damage.[171] At the same time, electricity demand is anticipated to grow in both developing and developed countries, as the rise of electric vehicles and electric heating will exceed even the most stringent efficiency measures.[132] This will raise demand during cold winter evenings, when demand is already highest in temperate countries, thus adding to the difficulties of maintaining secure, affordable and clean electricity.

Hydrogen technologies are able to assist with both the integration and expansion of low-carbon electricity generation and with the electrification of heating and transport sectors. Power generation from hydrogen is gaining ground – global capacity reached the milestone of 1 GW in 2015, as seen in the bottom right corner of Fig. 12a. Fig. 12b shows that the installed capacity of stationary fuel cells has grown by 25% per year. If this were maintained, fuel cells would reach 10 GW capacity in 2025, and 30 GW in 2030. However despite this growth, no company has yet turned a profit through sale of stationary fuel cells.[176]

Electricity generation

Fuel cells can benefit the electricity system in several ways: they are flexible, controllable, typically co-located with demand (minimising losses in transmission and distribution), and likely to generate when demand for electricity is highest if used for combined heat and power (thus helping to cope with peak demand). Additionally, hydrogen feedstock may be produced from power-to-gas, providing the large-scale long-term storage required to shift electricity from times of renewable surplus to those of shortfall.

It is important to note that the decarbonisation potential depends on the hydrogen feedstocks and supply chains. Any use of fossil fuel-derived natural gas to produce hydrogen (without CCS) will necessarily lead to carbon emissions that are at least at the level of a new CCGT power station.

Peak generation. With changes to turbine design, existing gas turbines can be converted to burn hydrogen rather than natural gas.[177] This is the hydrogen equivalent of business as usual: it allows grid operators continued access to low-cost thermal peaking plant and to operate much as they do now. Lack of hydrogen delivery infrastructure is an impediment, so the ETI suggests a system of on-site production and storage: a small steam-methane reformer (SMR) equipped with carbon capture and storage (CCS), a salt cavern for storage and a large open-cycle gas turbine (OCGT).[178] The other key disadvantage is the low efficiency of combustion relative to electrochemical conversion (35–40% *vs.* 40–60%), giving high operating costs.

A key advantage of fuel cells is that they retain their performance at smaller scales. Parasitic loads and thermal losses mean

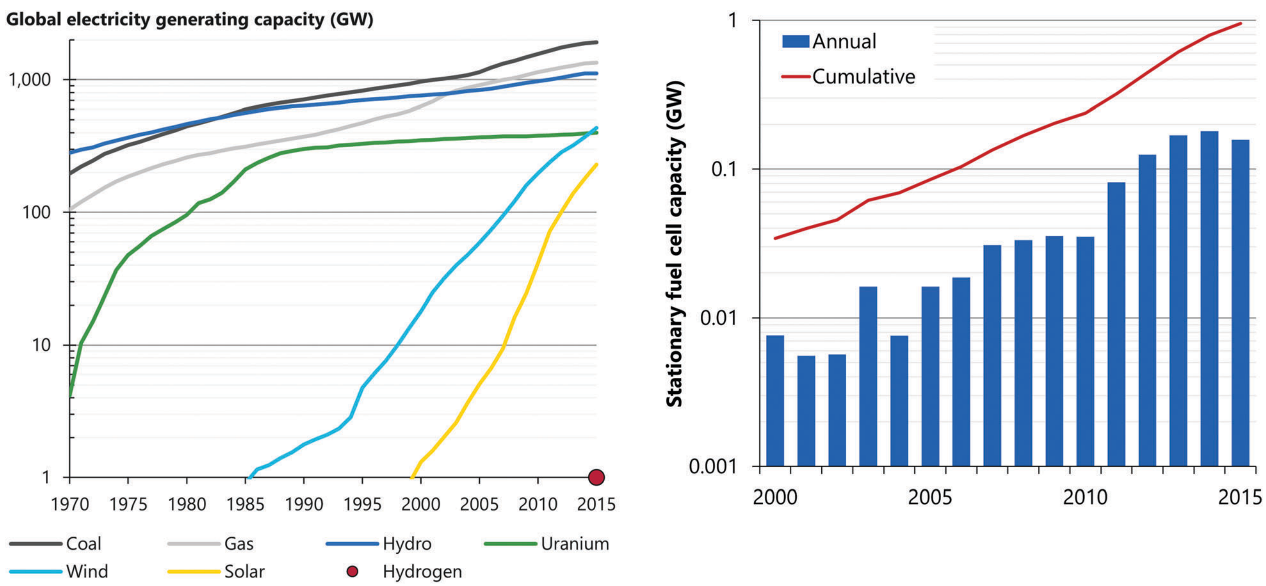

Fig. 12 Installed power generation capacity worldwide over the last 25 years (left),[164,172] and global installed power capacity of stationary fuel cells (power-only and micro-CHP) (right).[173–175] Annual growth rates since 2000 has been 52% for solar, 25% for fuel cells, 24% for wind, and 1–5% for other technologies.

the efficiency of other small-scale gas generators is at least a quarter lower than their larger (>10 MW) equivalents.[179,180] In contrast, fuel cells can deliver electrical efficiencies that are comparable to the best combined-cycle gas power stations (~60%) from several hundred kW down to 1 kW residential units.[145,181] Small, modular units can be co-located with centres of demand, saving on transmissions losses of around 7% in America and Europe,[134] and allowing fuel cells to provide ancillary services to the grid operator.

Power-only and backup fuel cells. Power-only fuel cell systems (*i.e.* without combined heat and power) are gaining popularity, particularly with American technology firms and multinationals seeking a green image. The units deliver cheaper electricity than local utilities (8–10 ¢ per kW h *versus* 14 ¢ per kW h),[182] and allow a move away from diesel engines as an uninterruptable power supply.

The Bloom Energy Server is a high-profile example, a 200 kW SOFC module that runs on either natural gas or bio-gas with an efficiency of 50–60%.[181] The first commercial units were installed at Google in 2008, and units can now be leased for either 10 or 15 years.[183] Bloom's announced contracts outstrip those of its three largest competitors combined.[184]

Energy Servers have received large subsidies from US green generation incentives (*e.g.* $200 million in California in 2010),[185] but carbon savings are relatively low. The carbon intensity of SOFC using natural gas is 350–385 gCO_2 kW h^{-1},[181] compared to new combined-cycle gas turbines at 360–390 gCO_2 kW h^{-1}, or the average British electricity mix at below 250 g kW h^{-1}.[186] Power-only fuel cells therefore match the best conventional production technology, but require decarbonised fuel sources to offer further carbon savings. For comparison, the carbon intensity of electricity from fuel-cell CHP (with a credit for co-produced heat) with natural gas feedstock is in the range 240–290 gCO_2 kW h^{-1},[119] lower than the average electricity mix in most large countries.

Vehicle-to-grid. Electrification of the transport sector has the potential to exacerbate the peak power problem if the charging of vehicle batteries is unmanaged.[187,188] The use of FCEVs rather than BEVs removes this issue, whilst also potentially delivering additional benefits. Private vehicles spend around 95% of the time parked, and so a large fleet of electric vehicles would provide grid operators with a reliable resource to call upon.[187]

Vehicle-to-grid (V2G) describes a system for communication with electric vehicles, allowing grid operators and utilities to access the energy stored within electric vehicles to meet demand and provide other grid services.[189] In this system FCEV might be able to act as a distributed source of peak power and spinning reserve,[190] though studies indicate that the economics for this scenario are marginal under current market conditions.[191,192] The increasing value of balancing services as electricity systems move towards more variable renewables may radically alter this in the future.[193]

A key barrier for drivers is the fear of being left 'out of gas' when an unexpected or emergency need to travel arises.[194] This 'range anxiety' is a key issue for BEVs due to range limitations, but not so for FCEVs as they could use their hydrogen tank for further top-up. For example, the Toyota Mirai, holds 5 kg of hydrogen, or 600 MJ of chemical energy (LHV basis). If this could be converted with 50% efficiency, then half a fuel tank would yield 40 kW h of electricity. With current battery technologies, the lifetime of a BEV would be reduced through participation in V2G, since additional charge/discharge cycles degrades the battery. Even with current lifetimes, it is expected that the fuel cell stacks would not be a chief determinant of lifetime in FCEVs.[190,194]

Electricity storage

With growing deployment of variable renewables and distributed generation, flexibility and control to balance supply and demand becomes increasingly valuable. There are already several technologies in various stages of maturity that allow the temporal shifting of electrical energy over time periods of hours to a few days (*e.g.* pumped hydro, batteries and compressed air electrical storage (CAES)). None of these can provide spatial redistribution of energy or storage on the week-month timescale that is required for balancing the output from wind generation.[195,196] Hydrogen technologies have the potential to meet both these needs.

Power-to-gas (P2G) refers to the process of converting excess electrical energy into storable chemical energy in the form of either hydrogen or grid-compatible methane – a key form of 'sector coupling'. Surplus electricity is used to power hydrogen production *via* water electrolysis. The resulting gas may then be stored and used when required, for instance by a fuel cell, or undergo further processing to produce methane, also known as synthetic natural gas (SNG). Equally, it can then be converted back to electricity or used to displace demand for natural gas in the heating (and power) sector, or indeed for transport. There are two commercially available processes for water electrolysis: alkaline electrolysis cells (AEC) and polymer electrolyte membranes (PEMEC); while solid oxide (SOEC) offers the possibility of high efficiency but are still at a development stage.[197] These technologies are described later in Section 5.1, and their market uptake is shown in Fig. 13. Globally, 30% of P2G pilot plants now use PEMEC,[198] and with rapid growth, prices are likely to fall to those of AEC by 2030.[199,200]

Power-to-hydrogen or power-to-methane? Hydrogen is superior to methane in terms of both process cost and simplicity.[201] In its most basic implementation, the process is being used to provide fuel for the rapidly-growing numbers of hydrogen filling stations. It is also the process in use in the majority of larger-scale P2G demonstration projects.[202] In the absence of a hydrogen distribution network, one key issue is the storage of the gas once it has been produced. From the range of alternatives,[203,204] storage in high pressure tanks is currently the favoured option. Another solution is to inject the resulting hydrogen into the natural gas network, although blending may be limited to 10–20% at most as explained in Section 5.4.4.

Onward conversion of the hydrogen to methane is a less efficient and significantly more complex process. Methanation of hydrogen is achieved *via* either a catalytic[207] or a biological

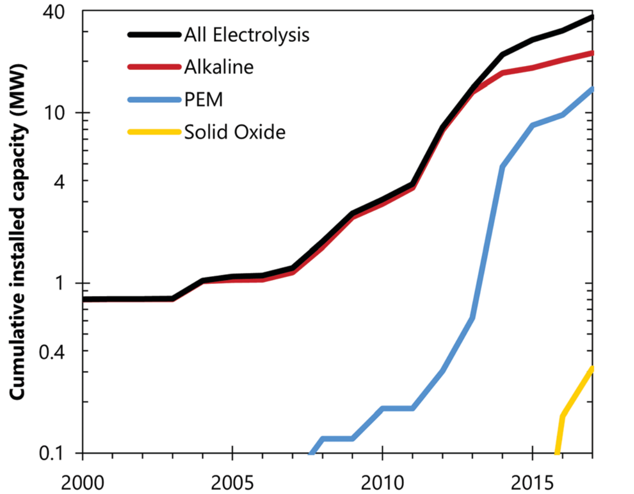

Fig. 13 Total installed power in existing power-to-gas pilot plants. Data from ref. 202, 205 and 206.

process,[208] and requires a source of CO or CO_2, plus compression and storage of the hydrogen feedstock. Overall, power-to methane has an efficiency in the range 49–65%, while power-to-hydrogen achieves efficiencies in the range 51–77%.[209,210] The roundtrip efficiency of a power-to-hydrogen-to-power process is in the range 34–44%, while for power-to-methane-to-power it is only 30–38%.[210] Estimates indicate that the levelised cost of power-to-methane is 15–30% more than for simple conversion to hydrogen.[198] The advantage of power-to-methane is the ability to feed directly into existing gas infrastructure. Globally, the energy storage capacity of the natural gas network is in excess of 3600 TW h,[211] approximately three times the global production from wind and solar power combined in 2016.[164] The source of CO or CO_2 is obviously central to whether power-to-methane aids carbon emission reductions: only carbon derived from biomass or direct air capture will be carbon neutral. There is a growing number of power-to-methane pilot projects in progress globally,[212] with Europe leading the way in driving forwards development of the technology.

Economics of power-to-gas. Several modelling studies have considered the economics of P2G under differing assumptions and scenarios.[198,203,213,214] Several authors conclude that P2G is not profitable at present, nor in the near-term: the costs are too high and the regulatory environment is unhelpful.[198,215–220] However, the studies show that P2G significantly reduces the need for curtailment of renewables[215,218] and that, where the resulting hydrogen is injected into the gas grid, further benefits may be gained from reduced costs and improved performance of both the gas and electricity grids.[216,218] The potential to exploit multiple revenue streams (*e.g.* selling H_2, CH_4 or O_2, providing ancillary services, heating, exploiting carbon levies, frequency control) improves the chances of profitability,[198] as does operating the plant so that it only uses renewable energy that would otherwise have been curtailed. The common message is that falling electrolysis costs and altered national regulatory frameworks should render P2G profitable within 10–15 years.[219]

Looking further ahead, several authors have examined the role that P2G might play in future national electricity markets with very high penetration of renewables. All studies indicate that P2G could play a pivotal role in balancing electricity systems once the penetration of VRE exceeds about 80%, in spite of the high cost and low efficiency.[209,217,221] With investment in hydrogen infrastructure, or increasing local demand for hydrogen, high-renewables scenarios envisage hundreds of GW of installed P2G capacity by the 2050s.

Hydrogen infrastructure

The development of hydrogen infrastructure is an important barrier to the widespread uptake of H2FC technologies. There is a perception that an all-encompassing 'hydrogen economy' must be established with enormous cost and duplication of existing energy infrastructure.[222–224] However, numerous production and distribution pathways exist, as summarised in Fig. 14, and include several incremental steps which do not require a wholesale infrastructure transformation. Developing a cost-efficient infrastructure from these options that may evolve over time with developing demand is a significant challenge.[225]

The upper half of Fig. 14 depicts centralised production methods that rely on new distribution networks, synonymous with the 'hydrogen economy' vision. Incremental and less infrastructurally-intensive routes also exist (the lower half of the figure), which utilise existing gas or electricity networks and reduce large up-front costs, albeit at the expense of lower efficiency. Indeed, H2Mobility concluded that only 60 small refuelling stations with onsite hydrogen production would be sufficient to supply most of the UK population in the early stages of a transition to fuel cell vehicles, with additional infrastructure deployed as demand increased.[77] This suggests that infrastructure development might not be as challenging as some have suggested.

Hydrogen production

Producing cost-competitive low-carbon hydrogen at a range of scales is arguably the greatest barrier to developing the hydrogen energy system.[226] Approximately 45–65 Mt year^{-1} hydrogen is produced globally as feedstock for chemical and petrochemical industries, equivalent to 5.4–7.8 EJ, or ~1% of Global energy supply.[227–230] Around half of this is produced by steam reforming natural gas, 30% from partial oxidation of crude oil products, 18% from coal gasification, and 4% from water electrolysis. Several emerging hydrogen production routes are at earlier stages of development,[226] including high-temperature steam electrolysis,[206,231] solar thermo-chemical water splitting (artificial photosynthesis)[232,233] and biological hydrogen production.[234,235]

Fossil fuels and biomass. Reforming is the conversion of hydrocarbons and steam into hydrogen and carbon monoxide (known as syngas). It produces relatively pure hydrogen with high efficiency, but is a slow endothermic reaction, and so does not react well to transient or stop/start cycling.[236]

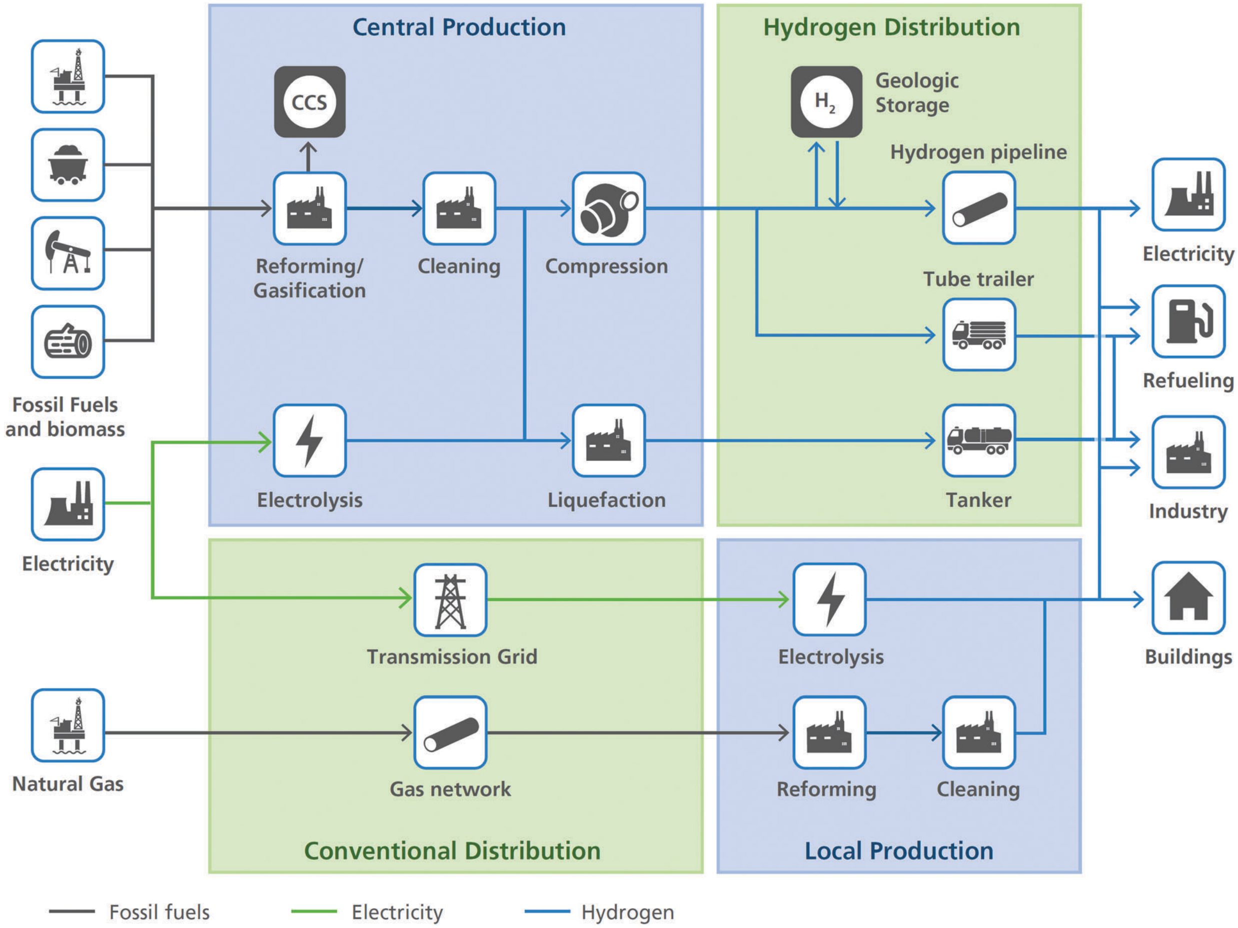

Fig. 14 Hydrogen delivery pathways discussed in this paper. This diagram is simplified and non-exhaustive, and serves to highlight the diversity of options at each stage of the system.

Partial oxidation is the incomplete combustion of a fuel-rich mixture to produce syngas. It is more versatile than reforming, allowing a greater range of fuels to be used, and proceeds more rapidly with no need for external heat input (allowing for smaller reactors); however, the hydrogen yield is lower (meaning more hydrocarbon feedstock is required), and the resulting gas requires additional cleaning.[237]

Gasification is the process of partially combusting coal or biomass at high temperature and pressure to produce syngas. This gives a faster reaction than steam reforming, but has higher costs as the solid fuel requires pre-treatment and the resulting syngas requires greater treatment.[197]

The vast majority of hydrogen is produced from fossil fuels, with CO_2 emission intensities depending on the feedstock and conversion efficiency.[238] Carbon capture and storage (CCS) could be feasible for large centralised production and could potentially deliver negative CO_2 emissions when using bioenergy feedstocks.[239,240] This relies on CCS maturing to the point of widespread rollout after 'a lost decade'[241,242] and on wider sustainability issues surrounding bioenergy supply-chains being carefully managed.[243,244]

Water electrolysis. Alkaline electrolysis cells (AEC) are the incumbent technology with a 100 year history, but polymer electrolyte membrane (PEMEC) are rapidly reaching maturity and are of particular interest for power-to-gas applications, while solid oxide electrolysers are transitioning from the laboratory to the demonstration phase.[200,208,245,246]

Alkaline electrolysers are the most mature, durable and cheapest technology.[247] A direct voltage current is applied between an anode and a cathode submerged in an alkaline electrolyte. Units can be several MW in size, but have a limited operating range (from a minimum of 20–40% to 150% of design capacity) and slow start-times.[203,205,208] With growing interest in integration with renewable energy, development aims to improve its dynamic operation.[199,245]

PEM systems were introduced in the 1960s and became commercialised in the last decade.[200] They have faster response and start-up and a wider dynamic range (0–200%), more suitable for intermittent power supply.[205,246] They have higher power density (and thus are smaller) due to their solid plastic electrolyte,[248] and have a high-pressure output (*e.g.* 80 bar) reducing the energy required for compression downstream. However, capital costs are currently approximately twice those of AEC,[199,200,249] and cell lifetimes need to improve.[202,208]

Solid oxide electrolysers (SOEC) use a solid ceramic electrolyte and operate at very high temperatures (700–900 °C),

Table 4 The efficiency and energy consumption of hydrogen production pathways. Data from ref. 161, 200 and 208

	Efficiency (LHV)	Energy requirement (kW h per kgH_2)
Methane reforming	72% (65–75%)	46 (44–51)
Electrolysis	61% (51–67%)	55 (50–65)
Coal gasification	56% (45–65%)	59 (51–74)
Biomass gasification	46% (44–48%)	72 (69–76)

enabling higher electrical efficiencies than other electrolysers.[248,250] Material degradation and lifetimes are critical shortcomings that must be improved.[200,251–253]

Capital costs for electrolysers are high, around \$1300 per kW for AEC and \$2500 per kW for PEMEC,[200] although these are declining rapidly,[249] whereas variable costs are governed by the electricity source. They also have high fuel costs for electricity, although the growing prospects of overproduction from intermittent renewables means zero (or negative) electricity prices are becoming more common.[254]

Production efficiency. Table 4 summarises the nominal efficiency and energy requirements for different hydrogen production methods. Early demonstrations have seen much lower efficiencies in practice though. For example, hydrogen production efficiency at dozens of filling stations in California and Japan averaged 55.8 $\pm$ 8.4% efficiency from natural gas,[255] while electrolysers averaged 55.9 $\pm$ 3.5% LHV (for those with >4 operating hours per day).[256–260]

Trade-offs. Of the various production routes, there are multiple trade-offs between scale of production, cost and GHG emissions. Natural gas, oil, and coal-derived hydrogen is lowest cost at large scales, but has poor environmental credentials. If CCS can be deployed, hydrogen from natural gas exhibits relatively low emissions with costs that will depend on the available CCS infrastructure.[261] However, GHG emissions may still be significant and will be governed by the carbon capture rate, and the embodied upstream supply chain emissions.[262] Methane emissions from shale gas productions vary widely between sites and are a key contributor to total global warming potential.[263] Biomass gasification may also offer large scale centralised hydrogen production, but at a higher capital cost.[261] Emissions are significantly lower than hydrogen from natural gas, but are again non-negligible and are largely dependent on the biomass feedstock. Hydrogen production from electrolysis is highest cost but is more suitable for small-scale generation given the modular nature of electrolysers. Total greenhouse gas emissions may be very low if supplied with low-carbon electricity (*e.g.* combined with offshore wind), and so electrolysis represents a key technology if cost profiles improve.

Hydrogen compression

Hydrogen is produced at a range of pressures across the different options and can be generated up to 15–80 bar by high-pressure electrolysers.[264] Hydrogen pipelines typically operate at such pressures, with regularly-spaced pipeline compressors used to maintain pressure over long distances. For storage, hydrogen must either be compressed or liquefied to obtain sufficient energy density. Highly-compressed gas is currently the preferred option for onboard vehicle storage, avoiding the expense and boil-off losses of liquefaction, the conversion losses of synthetic fuels such as ethanol and the technological immaturity of hydrogen carriers such as hydrides. Refuelling stations store hydrogen in in high-pressure tanks (825–950 bar) to allow fast refuelling despite the pressure drop across the dispenser.[265] Compressed hydrogen also needs cooling to -20 to -40 °C to avoid overheating the vehicle's tank.[161]

The energy penalty of compression to 875 bar is significant; estimated as 2.67 kW h kg^{-1} from 20 bar.[31,266] This means about 7% of the hydrogen's energy content is lost in refuelling a 700-bar vehicle. Standard compressor efficiency is around 70%, and while the US DOE has targeted 80% compressor efficiency by 2020, this is still low compared to some other compressor technologies.[265] While this is notably less than required for liquefaction, it still adds appreciably to the cost and carbon intensity of the resulting fuel. Compression costs are significant but not prohibitive, adding around \$1.50 per kg for pipeline and onsite production, or \$0.40 per kg from tube trailers.[265] These are not expected to change dramatically due to mature compressor technology.[267]

Mechanical compressors are the most mature technology for hydrogen, although they suffer poor reliability and are a leading cause of downtime in hydrogen refilling stations.[265,268] Within this category, centrifugal compressors are used in centralised production and pipelines, and piston compressors are used for high-pressure refuelling stations.[269] Electrolysis can generate hydrogen at pressures up to 200 bar with higher efficiency than mechanical technologies.[264] Less mature technologies include electrochemical, ionic and hydride compressors (Table 5).[31]

Liquefaction. Liquefaction of hydrogen greatly increases its energy density, allowing large-scale transport by road tanker or ship which is particularly attractive for long distances where pipelines are not economically feasible.[48] Over 90% of merchant hydrogen is transported as liquid in the US, indicating the maturity of liquefaction technology.[270]

Liquefaction consumes considerably more energy than compression, as seen in Table 6. The US's 2020 target for the energy consumption of large-scale liquefaction is 11 kW h kg^{-1}, with the potential to reduce to 6 kW h kg^{-1} in the long-term.[270] All large-scale hydrogen liquefaction plants are based on the pre-cooled Claude system and while several alternate designs have been proposed, "they are still neither more efficient nor realistic".[274] For context, 11 kW h is one third of the LHV content of a kg of fuel, so if the electricity input is produced with 50% efficiency, liquefaction adds 0.66 units of primary energy consumed per unit of delivered hydrogen.

Hydrogen purity

The ISO 14687-2 standard for transport PEMFCs requires 99.97% purity hydrogen,[275] and all fuel cell systems have tightly-controlled specifications on input purity to preserve cell lifetimes (Table 7). High temperature SOFCs and MCFCs have the advantage of being the most fuel-flexible technologies, in some cases able to use methane and carbon monoxide directly

Table 5 Advantages and disadvantages of compression technologies

Technology	Advantages	Disadvantages
Mechanical[265,268,269]	+ Commercially available + Wide operating range	– Low efficiency (∼70%) and expensive – Poor reliability due to many moving parts – Regular maintenance due to start-ups – Purification due to oil contamination
High-pressure electrolysis[246,264]	+ High efficiency + Production at 50–200 bar + High temperature reduces energy use	– Strong materials needed (increasing cost) – Increased cross-over and back-diffusion losses – Long start-up times requires stable supply
Electrochemical[7,271,272]	+ High efficiency + 1000 bar demonstrated + High reliability (no moving parts) + Pure output (no oil contamination)	– Strong materials needed (increasing cost) – Back-diffusion and resistive losses – Trade-off against throughput and efficiency – Pure inlet required and needs drying
Ionic[273]	+ Low contamination + High efficiency + Reliable (few moving parts)	– Expensive and unproven – Limited throughput to avoid foaming
Hydride[246]	+ Compact, reversible + Reliable (few moving parts)	– Expensive and unproven – Heavy

Table 6 The efficiency and energy consumption of hydrogen distribution pathways, assuming production at 20 bar. Data from ref. 161 and 208. The energy penalty is measured relative to the LHV energy content of hydrogen, and assumes electricity is produced with 50% efficiency (generation plus distribution)

	Energy penalty (*vs.* LHV)	Electricity requirement (kW h per kgH_2)
Compression to 500 bar (including cooling)	15% (12–24%)	2.6 (2–4)
Compression to 900 bar (including cooling)	21% (18–30%)	3.5 (3–5)
Liquefaction	78% (66–90%)	13 (11–15)

Table 7 Summary of fuel tolerance for different fuel cell types. Data from ref. 151 and 236

	Sulphur (S, H_2S)	Carbon monoxide (CO)	Ammonia (NH_3)
PEMFC	<0.1 ppm	<10–100[a] ppm	Poison
PAFC	<50 ppm	<0.5–1%	<4%
MCFC	<1–10 ppm	Fuel	<1%
SOFC	<1–2 ppm	Fuel	<0.5%

[a] Standard Pt anode catalysts can only withstand CO concentrations up to 10 ppm, and PtRu alloys up to 30 ppm. These limits can be extended by bleeding air into the anode and using alternative bi-layer catalysts.

as a fuel. PAFCs are tolerant to around 1% CO; however, the Pt catalyst in the PEMFC is easily poisoned, and so the CO present in syngas must be removed or converted. Sulphur is a critical poison to all fuel cells, which is problematic due to its use as an odourant in natural gas for safety reasons.

Hydrogen from electrolysis. Hydrogen produced from water electrolysis is typically pure enough for FCEV applications, as recombination catalysts remove oxygen that crosses the membrane.[276,277] The main contaminant is water vapour which, although required for fuel cell humidification, corrodes and erodes the compressing, storing and transporting equipment. It can also freeze in cold temperatures, damaging pipework and valves. Electrolysers therefore normally include dryers, typically regenerative desiccant towers, which are low-cost with low power consumption. However regeneration either involves electrical heating, or sending some dry gas back through the wet tower to pick up the accumulated moisture, typically reducing yield by around 10%, though there is scope for reducing this.[278]

Hydrogen from steam methane reforming. Hydrogen from reformed natural gas needs several clean-up stages if used in low-temperature fuel cells, as shown in Fig. 15. Pressure-swing adsorption (PSA) is the incumbent technology for separating hydrogen from carbon dioxide and other contaminants, and is capable of achieving hydrogen purities of >99.9% at the expense of loss of yield.[238,279] Hydrogen purification costs from SMR have been estimated as \$0.70 per kg, projected to fall to \$0.40 per kg in 2025.[7]

An alternative to PSA is pressure-driven diffusion membranes, typically palladium-based. Current palladium filters achieve

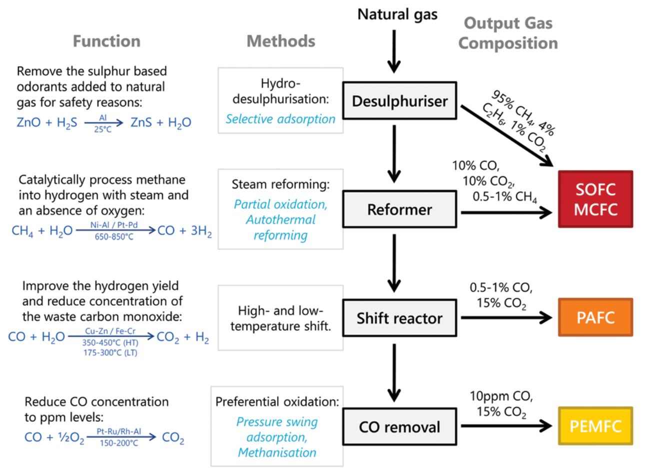

Fig. 15 An overview of fuel processing for fuel cell systems. Each stage is highlighted in bold, and given with the most common methods that are used; for each stage, the primary method is highlighted in italics. A description of each stage is given at the far left, along with the ideal reactions for the primary method. Indicative ranges of gas composition after each stage are given to the right. Following the stages down from natural gas to each type of fuel cell on the right indicates which processing stages are required. Data from ref. 147 and 151.

exceptionally high purity but are expensive, require a 400 °C operating temperature and a pressure differential of 10–15 bar,[280] reduce yield by 3–5%, and can suffer short lifetimes. One study found a palladium-based separation system that is potentially cheaper than PSA[280] and further research is required to determine potential for diffusion membranes and electrochemical compressors.[7]

Hydrogen from pipelines and storage. Hydrogen extracted from pipelines and/or salt-cavern storage requires onsite cleaning before FCEV usage to remove lubricants, odourants, colourants, debris or dust acquired. Odourants are likely needed to warn against leaks; cyclohexene has been found to be compatible with fuel cell technology in Japan, but is described as having too pleasant a smell and lacking the stench of current EU odourants.[144,238] A colourant may also be required to warn users of fires, as hydrogen burns with a colourless flame; an extremely dilute strontium solution is being considered.[281] It may be that PSA or activated carbon filters would be appropriate for onsite purification. The cost of cleaning hydrogen from pipelines is currently an unknown and requires further work.[282]

Hydrogen distribution

There are typically three routes for hydrogen distribution, the suitability of which depends on the size of demand and the transportation distance (Table 8). Compressed hydrogen transport *via* tube trailers is likely to assist initial rollout, whereas pipelines are better suited for mass deployment. Pipelines could provide scalability if heat, power and industry converted to hydrogen as well as transport. Liquefaction could be used for international shipping of bulk hydrogen; distribution of liquefied hydrogen by road could be restricted to a few heavy-duty transport sectors.

Gas tube trailers. An option for low demand, such as during initial rollout, is distributing hydrogen from centralised production facilities as a compressed gas in tube trailers. This is well-established, and large trailers for FCEV refuelling hold 1000 kg capacity at 500 bar.[7] The trailer can be parked at the refuelling station to refuel vehicles directly, reducing onsite storage and compression requirements as compression begins from a much higher starting pressure. However, this uses valuable surface space at the refuelling station and delays the trailer's return for its next load. Tube trailers become less economic as demand rises and over long distances,[48] but remain an attractive near-term solution for its lower infrastructure cost and risk.[283] Longer term it could still present the best option for remote or low-demand areas.[48]

Liquid hydrogen tankers. Liquid hydrogen tanker capacities are typically 2000–7500 kg and have greater density than compressed storage.[48] This would likely pose additional safety restrictions, as applied to industrial sites using hydrogen.[48] Despite early interest in using liquid hydrogen for vehicles, boil-off results in high storage losses for low-utilisation vehicles and is potentially unsafe for parking in enclosed spaces.[284] While lower density compressed hydrogen offers sufficient range for personal vehicles, heavy-duty transport sectors (*e.g.* trucks and ships) may still be better served by liquid hydrogen.[13]

Table 8 Qualitative overview of hydrogen transmission and distribution technologies for the transport sector[4]

Distribution route	Capacity	Transport distance	Energy loss	Fixed costs	Variable costs
On-site production	Low	Zero	Low	Low	High
Gaseous tube trailers	Low	Low	Low	Low	High
Liquefied tankers	Medium	High	High	Medium	Medium
Hydrogen pipelines	High	High	Low	High	Low

Gas pipelines. Pipelines are regarded as the most efficient method of transporting large quantities of hydrogen over short distances.[48] Around 3000 km of high-pressure hydrogen pipelines are already in use in Europe and North America for industrial processes.[48] However, high costs prevent further pipeline development until sizeable and consistent demand for hydrogen can be assured.

Low initial utilisation and high upfront costs are likely to hinder financing.[48] Existing high-carbon steel natural gas pipelines might fail if repurposed due to hydrogen embrittlement, so new high-grade steel construction would be required.[285] Embrittlement is not a concern at lower pressures[286] and newer polythene natural gas pipes being installed across the UK and Europe are hydrogen compatible.[287] These polythene pipes are currently limited to 7 bar, but larger plastic pipes up to 17 bar have been proposed.[48] Hydrogen pipelines have long lifetimes (50–100 years), although the rate of embrittlement in steel pipelines can make this difficult to predict.[48]

Blending hydrogen into natural gas. Hydrogen can be safely mixed in small quantities with natural gas and injected into the existing gas network, but administrative and technical constraints limit the permissible fraction of hydrogen. The level of hydrogen that could be safely added depends on the distribution system and end-use appliances. The UK and US have amongst the lowest legal limits of any country at 0.1%, compared to 10–12% (by volume) in Germany and the Netherlands (Fig. 16, left).

Current research aims to refine this range of allowable injections.[280,288–291] A Dutch study concluded that off-the shelf gas appliances operated with no serious problems with up to 20% hydrogen blends by volume.[292] Similarly, the Health and Safety Laboratory concluded that 20% hydrogen was unlikely to harm the UK gas network or most appliances, although the identification and modification of vulnerable appliances is required for concentrations above 10%.[143] The different combustion characteristics of hydrogen may interact differently across the wide range of gas appliances in use, many installed decades ago.

Even if limits were relaxed, a 20% blend would represent only 7% hydrogen by energy content, due to its lower density than methane. The share of hydrogen by energy content (E_H) is calculated from the volume percentage (or mole fraction) of hydrogen (V_H) and methane (V_M) as in eqn (1):

$$E_H = \frac{11.88V_H}{11.88V_H + 39.05V_M} \quad (1)$$

where 11.88 and 39.05 are the volumetric HHV energy content of hydrogen and methane respectively (MJ m^{-3}),[293] and $V_M = 1 - V_H$ by definition.

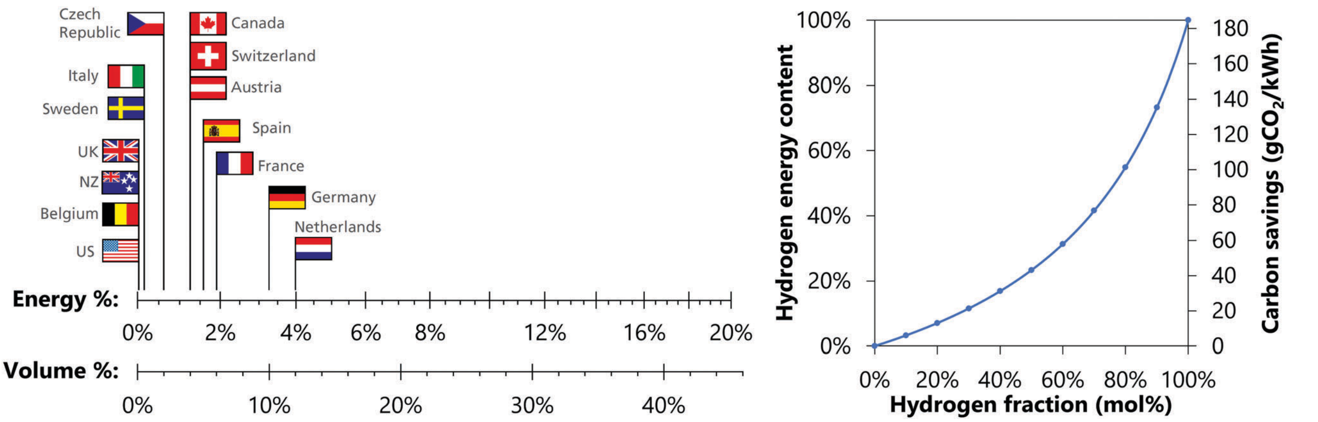

Fig. 16 Limits on hydrogen blending into national gas grids around the world, using data from ref. 304 (left); and the relationship between energy content, carbon savings and hydrogen injection mixtures (right).

The direct carbon emissions savings of a 20% (volume) hydrogen blend would be 13 gCO_2 per kW h (Fig. 16, right), so hydrogen injection alone could not achieve deep decarbonisation of the gas network. That said, this amount of hydrogen blending would deliver most of the decarbonisation required in UK buildings to 2030 (a 10% reduction on 2015 emissions),[22] not accounting for upstream hydrogen supply chain emissions.

Converting the natural gas network to hydrogen. An alternative to blending is complete conversion of existing natural gas distribution networks to distribute hydrogen. Consumer satisfaction with gas heating indicates this could be a popular low-carbon choice;[294] although the UK is among the only countries actively considering this option, *e.g.* with the Leeds H21 project[238] or in the North of England.[295,296] In the 1970s, Britain converted from town gas to natural gas progressively over 11 years, with all networks converted in parallel.[297] Early desk studies have shown that conversion back to hydrogen could be technically feasible and economically viable.[15,238] Such a switch would likely take 10–20 years, with appliances in every building being systematically converted or replaced and careful planning to ensure continuity of supply.[238]

Gradual conversion of the heating stock as products reach their end of life; with a roll-out of 1 million properties a year at a cost of $$5000 per house is considered feasible.[48] This transition period may require ''hydrogen-ready'' boilers capable of running on both natural gas and hydrogen. While this is thought of as uneconomical,[144] it was used in the gradual roll-out of digital television and in plans for ''CCS-ready'' power stations.[298] Legislating for standardised backplates for all new boilers would greatly reduce the cost and time required for such a conversion.[299]

Hydrogen storage

Bulk storage. Large-scale hydrogen storage is one of the few low-carbon solutions to balance long-term intermittency in electricity generation from wind and solar power, especially in relation to inter-seasonal shifts (see Section 4.2).[214,300] As with compressed air energy storage (CAES), hydrogen can be stored in compressed form in underground salt caverns.[301] Hydrogen offers energy densities of 280 kW h m^{-3} – 100 times greater than for compressed air.[48] A limited number of regions have suitable salt deposits, but several chemical and refinery complexes have used substantial hydrogen salt cavern storage facilities since the 1960s.[48] Operational projects include a 24 GW h facility in the UK and an 83 GW h facility in Texas.[302] Hydrogen is currently the only low-carbon technology able to store over 100 GW h and operate over a timescale of weeks or even months, although this is countered by low round-trip efficiency and high equipment costs.[302,303]

If hydrogen were delivered by pipeline for heat and electricity provision, line-packing (using the compressibility of gas within the network) combined with geologic storage could balance supply and demand. However, significant high-pressure decentralised storage is required for transport applications due to space constraints, particularly at refuelling stations and on-board vehicles. Higher pressures increase tank material and compressor specifications, compression work requirements and safety measures such as minimum separation distances at forecourts. Low ($\sim$45 bar) and medium pressure (200–500 bar) pressure vessels are common in industry, but high pressure tubes and tanks (700–1000 bar) are almost exclusively used for FCEVs and refilling stations, and are currently produced in low quantities.[48] Hydrogen tanks at refuelling stations have higher pressures than in FCEVs (*e.g.* 925 *vs.* 700 bar) to allow rapid refuelling without requiring a slow compressor to fill vehicle tanks. Compressed hydrogen gas has only 15% the energy density of petrol, so refuelling stations require more physical space to supply the same amount of fuel. This could be offset by using underground storage at refuelling stations to reduce surface land usage in densely populated urban areas. Even then it is possible that many existing urban refuelling stations would not be suitable for hydrogen if they were remote from the high-pressure hydrogen network.[48]

Alternative hydrogen carriers. Hydrogen can also be distributed in the form of fuels such as ethanol, CNG or ammonia,[305] which can be low-carbon if produced from biomass or non-fossil fuel sources. These could offer low-pressure, high-volume energy carriers similar to those used extensively today.

However, biomass availability is limited and synthetic fuels are costly and difficult to produce, so these options are not currently under widespread consideration.

A number of alternative hydrogen carriers with lower technology-readiness levels are currently under investigation. Solid carriers including metal hydrides are already established in a few niche applications including submarines and scooters.[48] They operate at low pressure and hence require lower safety restrictions and separation distances than highly-compressed or liquefied hydrogen, making them attractive in densely-populated areas. Their gravimetric energy density (around 3% hydrogen by weight) is comparable to compressed gas at 500 bar.[306] Borohydrides are a promising option being researched, potentially offering over 10 wt% storage.[307,308]

Energy is released during charging (*i.e.* hydrogenation), but energy input of about 30% is required during discharging.[48] Hydrides have cheaper system components (*e.g.* a small compressor, a heater for discharging) than for compressed or liquefied hydrogen storage. Slow charging and discharging rates limit their suitability for on-board applications, meaning that the hydrogen must be released from the hydrides at the refuelling stations and compressed for on-board storage.

Liquid organic hydrogen carriers (LOHCs) attain densities of 6 wt%, and like hydrides they offer low pressure operation and improved safety.[48] Around 25% of the energy content of hydrogen is required to release the fuel, though this could be offset if the equivalent amount of energy released during hydrogenation could be captured.[309] Catalysts can be employed to speed up the reactions, potentially enabling their usage on-board vehicles hence avoiding compression requirements. Recently, discarded cigarette butts were discovered to hold over 8 wt% hydrogen after thermal processing, potentially creating a new class of hydrogen store from a toxic waste product.[310]

For comparison, 700 bar compressed hydrogen tanks offer 5.7 wt% hydrogen storage (using the Toyota Mirai as an example).[311] The DOE target improvement to 7.5 wt% at a cost reduction from $$33 per kW h at present to $$8 per kW h.[312]

Policy challenges

International policy context

Globally, relatively few energy policies apply directly to H2FC technologies. Policies aimed at reducing GHG emissions such as feed-in tariffs focus on renewables and exclude non-green hydrogen, while policies that tackle energy affordability generally exclude hydrogen and fuel cells due to their current high costs.[31]

This is slowly changing, as some countries extend their policies to include H2FC technologies. For example, European hydrogen refuelling infrastructure is now promoted under the Alternative Fuels Infrastructure Directive,[313] and while the current Renewable Energy Directive (RED) accepts renewable biofuels and bioliquids that save at least 60% GHG emissions, hydrogen is excluded.[314] However, the revised RED will be broadened to include hydrogen from 2021, with pathways saving 70% GHG emissions being classified as a renewable fuel of non-biological origin,[315,316] which may encourage countries to give policy support to hydrogen supply chains. Support exists in the US, with eight federal programs having some scope to promote H2FC uptake, although individual states define the supporting mechanisms, meaning FCEV rebates range from zero to $$5000 per vehicle.[317]

Table 9 summarises the national targets for H2FC technology uptake in six leading countries, and Table 10 compares the level of financial support provided to achieve these. Whilst these

Table 9 Summary of hydrogen and fuel cells uptake targets. Data from ref. 325, 334 and 340

	CHP		Fuel cell cars			Refuelling stations		
Country	2020	2030	2020	2025	2030	2020	2025	2030
Japan	1.4m	5.3m	40 000	200 000	800 000	160	320	900
Germany	—		100% ZEV[a] by 2040			400		—
China	—		3000[b]	50 000	1m	100	1000	—
US	—		0	3.3m	—	100[c]	—	—
South Korea	—	1.2 MW	10 000	100 000	630 000	100	210	520
UK	—		100% ZEV[a] by 2040			30	150	—

[a] Zero emission vehicle. [b] Shanghai only. [c] California only.

Table 10 Summary of the support offered in various countries for hydrogen and fuel cells in 2017. Data from ref. 317, 325, 334 and 341–350. Values given in 2016 US Dollars, converted as ¥102 = €0.75 = CNY 3.5 = KRW 894 = £0.69 = $1

Country	Residential CHP	Fuel cell vehicles	Refuelling
Japan	$93m $700–1700 per unit	$147m	$61m
Germany	$13 600 per unit	$4000 per vehicle	$466m
China	—	$1700 per kW (up to $57 000 per vehicle)	$1.1m per unit
US	$1000 per unit (up to $3000 per kW for larger systems)	Up to $13 000 per vehicle	30% of cost (up to $30 000) (California $100m up to 2023)
South Korea	$5.3m	$5.4m (up to $31 000 per vehicle)	
UK	—	$33m (60% of cost for refuelling)	

demonstrate ambition towards FCEV uptake, incentives are smaller than for other technologies. For example, the UK budget for hydrogen transport projects is £23m, while the funding for BEV recharging and manufacturing infrastructure is £646m.[318] Additionally, the UK supports only biogas combustion micro-CHP devices rather than fuel cell CHP, whilst there is support for battery electric vehicles but not fuel cell vehicles.[319]

Policy support for H2FC technologies are driven by various national priorities, including air quality, climate change,[31] energy security,[320] affordability and economic growth.[321] US policy is driven by the need to improve air quality due to transportation; thus there are no national targets for deploying fuel cells in stationary applications. China aims to reduce severe urban air quality issues and boost economic growth through manufacturing fuel cells as part of the "Made in China 2025" strategy.[322] In Japan, hydrogen is promoted to provide energy security through improving efficiency, to support national industries and revitalise regional economies and reduce environmental burdens.[323]

Japan envisions a three stage transition to a hydrogen society: promoting FCEVs, hydrogen production and residential fuel cells (currently); developing and integrating hydrogen supply chains into the energy system (by 2030); and finally establishing a carbon-free hydrogen supply by 2040.[324] In contrast, the main driver in Europe is reducing GHG emissions, with hydrogen also seen as a critical part of the industrial strategy of countries such as the UK.[325] The UK and France plan to halt the sale of new petrol and diesel cars from 2040[326,327] and the Netherlands from 2030.[328] Norway aims to replace sales of diesel cars with electric and hydrogen passenger cars from 2025.[329]

Current market size

Evidently, countries that have provided stronger incentives and broader strategies (Table 10) have seen greater uptake of H2FC technologies, as shown in Table 11. Fuel cell vehicles are an area where the US is leading, with 2750 FCEVs sold as of 2017, more than in Japan and Europe combined.[330,331] China's stance on fuel cells could have global implications;[90] its 2016 Fuel Cell Vehicle Technology Roadmap includes a modest target for 5000 FCEVs in 2020 but a scale of millions in 2030.[332]

Fig. 17 illustrates the extent to which Japan is leading fuel cell CHP rollout: South Korea and Europe trail by a decade, and the US has seen very limited uptake. In 2012, fuel cells outsold engine-based micro-CHP systems for the first time, taking 64% of the global market.[333] Japan has deployed 98% of the world's residential fuel cell systems with over 223 000 systems sold as of October 2017.[334,335] The dotted lines in Fig. 17 indicate the Japanese government's target of 1.4 million fuel cells installed by 2020,[336] although Bloomberg forecast that only a quarter of this target will be reached as subsidies have fallen too quickly to offset high costs and competition from rooftop solar. Toshiba recently exited the industry, leaving only two EneFarm manufacturers.[337] The European Union originally anticipated 50 000 systems by 2020, but only 1046 systems were installed in the ene.field project,[338] and 2650 additional units will be installed by 2021 as part of the PACE demonstration.[339]

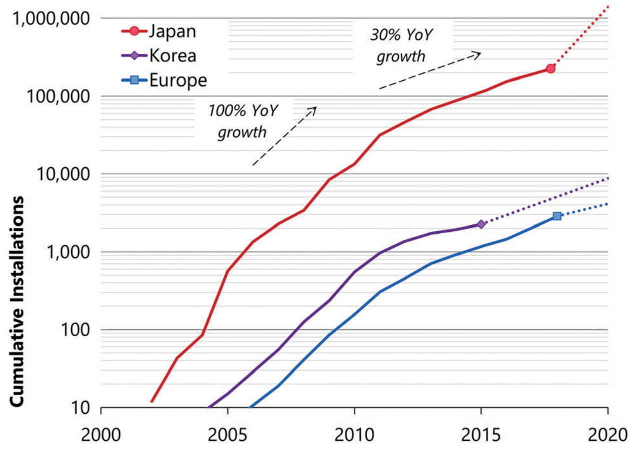

Fig. 17 Cumulative number of residential micro-CHP systems installed to date (solid lines) and near-term projections (dotted lines). Data from ref. 16, 339, 355 and 356.

Strong policy signals can evidently yield substantial benefits, as seen by the uptake of home heating systems and vehicles deployed in Japan, and the strength of Japanese manufacturers. Demonstration projects that enable learning-by-doing through manufacturing scale-up have been necessary for decreasing the price of H2FC technologies as with other technologies. However, the scale of such demonstration programmes has arguably been trivial outside of Japan. For context, the two largest demonstration projects in Europe (ene.field and PACE) target just 3% the number of households that received solar PV panels in Germany's 100 000 roofs programme over a decade ago.[353]

Policy drivers for hydrogen and fuel cells

The drivers for promoting hydrogen and fuel cells in energy policy relate to improving the reliability, efficiency and security of the energy system, reducing environmental impacts, and developing new low-carbon industries, with their associated

Table 11 Summary of hydrogen and fuel cells uptake as of 2018. Data from ref. 76, 331, 334, 340, 351 and 352

Country	CHP units	Fuel cell vehicles	Refuelling stations	Forklift trucks
Japan	223 000	1800 cars	90	21
Germany	1200	467 cars, 14 buses	33	16
China	1	60 cars, 50 buses	36	N/A
US	225 MW	2750 cars, 33 buses	39 public, 70 total	11 600
South Korea	177 MW	100 cars	11	N/A
UK	10	42 cars, 18 buses	14	2

employment opportunities and skills. The potential of H2FC technologies to contribute to all the dimensions of sustainable development (environmental, social and economic) arguably justifies their systematic and long-term policy support.

Several European countries are working to define green hydrogen standards, showing a concern for the climate benefits from fuel cells rather than just the level of uptake.[354] Some standards focus on hydrogen from renewable sources, others include hydrogen from low-carbon sources (including nuclear and CCS). These differences must be resolved if a pan-European or global certification scheme is to be agreed.[31]

A changing climate, natural disasters, war and cyber-security flaws can have extreme impacts on energy supply chains.[320] H2FC technologies can support the electricity system in balancing weather-dependent renewables, and hydrogen can improve national energy self-reliance, as it has numerous production pathways. Hydrogen can also be produced anywhere, which makes it particularly attractive to oil-deficient countries as one of the principal alternative fuels with a considerable potential for long-term substitution of oil and natural gas.[313]

Hydrogen and fuel cells are currently more expensive in most applications than their low-carbon competitors. However, they possess some superior characteristics to these competitors, which could aid the public acceptability of decarbonising personal energy use. The steep cost reductions seen for fuel cells in Asia (see Section 3.2) suggest that programmes to support for research, development and deployment can significantly influence the economic viability of H2FC technologies. Japan's Hydrogen and Fuel Cell Roadmap, the US DOE Hydrogen and Fuel Cells Program, and Europe's Fuel Cells and Hydrogen Joint Undertaking (FCH-JU) are prominent examples.

Conclusions

Hydrogen has fallen in and out of favour since the oil shocks of the 1970s and remains a marginal energy system option. However, mainstream products are now emerging: Honda, Toyota and Hyundai have launched the first mass-produced hydrogen fuel cell vehicles, and fuel cells now heat 225 000 homes. Early-mover companies, notably in Japan, are beginning to see lucrative export opportunities.

Hydrogen can play a major role alongside electricity in the low-carbon economy, with the versatility to provide heat, transport and power system services. It does not suffer the fundamental requirement for instantaneous supply-demand balancing, and so enables complementary routes to deeper decarbonisation through providing low carbon flexibility and storage. The numerous hydrogen production, distribution and consumption pathways present complex trade-offs between cost, emissions, scalability and requirements for purity and pressure; but provide a multitude of options which can be exploited depending on local circumstances (*e.g.* renewable energy or suitable sites for CO_2 sequestration).

Hydrogen and fuel cells are not synonymous; they can be deployed in combination or separately. Fuel cells can operate on natural gas, which avoids combustion and thus 90% of airborne pollutants. Hydrogen can be burnt in engines and boilers with no direct CO_2 and near-zero NO_x emissions. When used together, hydrogen fuel cells are zero-emission at the point of use, with overall emissions dependent on the fuel production method (as with electricity).

Fuel cell vehicle costs are high relative to battery electric vehicles, but with mass production they can achieve parity by 2025–2030. Driving range and refuelling time are significantly better than premium electric vehicles, which is particularly advantageous for buses, heavy goods and other highly-utilised vehicles. As with electric vehicles and unlike biofuels, fuel cell vehicles can tackle urban air quality problems by producing zero exhaust emissions. This has the potential to drive deployment in cities, railways, airports, seaports and warehouses.

Innovations in heat decarbonisation lag behind other sectors as heat pumps, district heating and burning biomass face multiple barriers. Households are accustomed to powerful, compact, rapid response heating systems, which can be modified to use hydrogen. Fuel cell combined heat and power can operate on today's natural gas network, albeit with limited carbon savings. Hydrogen presents various options for decarbonising this network in the longer term.

Hydrogen technologies can support low-carbon electricity systems dominated by intermittent renewables and/or electric heating demand. Fuel cells provide controllable capacity that helpfully offsets the additional peak demand of heat pumps. In addition to managing short-term dynamics, converting electricity into hydrogen or other fuels (power-to-gas) could provide the large-scale, long-term storage required to shift renewable electricity between times of surplus and shortfall.

Hydrogen applications and the supporting infrastructure may be installed incrementally and simultaneously, with care taken to avoid potentially high-regret investments early on. Existing electricity and gas infrastructures can be used for on-site hydrogen production in distributed refilling stations and fuel cell heating. Focussing on specific users such as captive vehicle fleets (*e.g.* urban buses with central refuelling depots) could provide the high utilisation and demand certainty needed for investment. Given the diversity of decarbonisation pathways, a clear strategy will reduce the costs of introducing hydrogen and fuel cell technologies.

Successful innovation requires focused, predictable and consistent energy policy, which is probably the single greatest challenge in realising the hydrogen and fuel cell potential. Stop-go policies, and frequent, unexpected policy changes undermine the confidence that businesses and industry need to make long-term investments in low-carbon technologies such as hydrogen and fuel cells. Countries should develop a system of policy support for hydrogen and fuel cell technologies that offers the long-term stability needed for large, transformative investments to be made. Policy reviews, decision points and milestones in a support programme should be announced well in advance, with ongoing support conditional on meeting reasonable performance and cost targets. Given such sustained support, and the technological progress in hydrogen and fuel cells in recent years, there are strong grounds for believing that hydrogen and fuel cells can experience a cost and performance trajectory similar to those of solar PV and batteries, and in the medium term provide another important and complementary low-carbon option with versatility to be deployed in multiple uses across the energy system.

Conflicts of interest

There are no conflicts to declare.

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