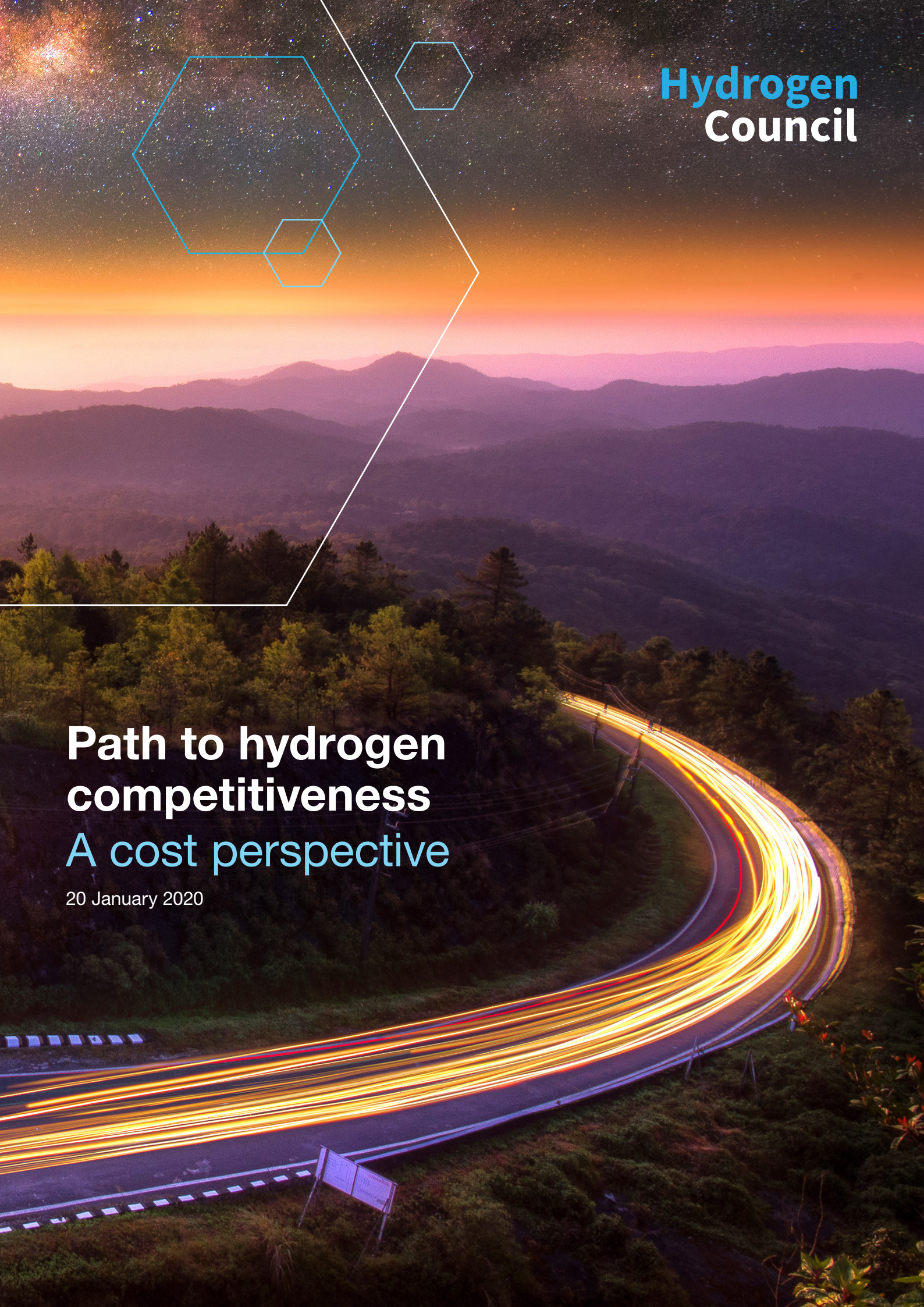

Hydrogen Council

Path to hydrogen competitiveness

A cost perspective

20 January 2020

Published in January 2020 by the Hydrogen Council. Copies of this document are available upon request or can be downloaded from our website: **www.hydrogencouncil.com**.

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2. It is not their intention that any such form of coordination will be adopted.

Whilst the contents of the Report and its abstract implications for the industry generally can be discussed once it has been prepared, individual strategies remain proprietary, confidential and the responsibility of each participant. Participants are reminded that, as part of the invariable practice of the Hydrogen Council and the EU competition law obligations to which membership activities are subject, such strategic and confidential information must not be shared or coordinated – including as part of this Report.

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Executive summary

A path to hydrogen cost competitiveness

As public pressure is rising to limit global warming to 1.5 degrees Celsius, global leaders are grappling with how to best take on this unprecedented challenge. Full decarbonisation requires a multidimensional strategy, which has spurred renewed interest in hydrogen. Governments are recognising hydrogen's ability to decarbonise sectors that are otherwise impossible or difficult to abate – such as intensive personal or collective transport, freight logistics, industrial heating and industry feedstock – and its role in energy security. Meanwhile, industry leaders across the automotive, chemicals, oil and gas, and heating sectors look to low-carbon hydrogen as a serious alternative to reach their increasingly substantial sustainability objectives.

The Hydrogen Council's previous report, 'Hydrogen Scaling Up', showed the critical role hydrogen could play in global industrial decarbonisation. Since then, technological advances and early demonstration projects have significantly lowered the cost of many hydrogen applications. Yet despite rapid improvements in recent years and a clear prospect for further cost reduction, the competitiveness trajectory and required investments to reach the scale at which hydrogen is competitive remain unclear to many.

This report provides an evidence base on the path to cost competitiveness for 40 hydrogen technologies used in 35 applications. For policymakers, such a perspective provides firm ground on which to base financial and non-financial support that will unlock the economic value of hydrogen and to develop adequate policy frameworks. For decision-makers in industry, it brings a holistic picture of whole value chain cost dynamics and interactions, allowing them to put their own efforts into a broader perspective.

Scaling up hydrogen value chain to unlock further cost reductions

Our findings suggest that scale-up will be the biggest driver of cost reduction, notably in the production and distribution of hydrogen and the manufacturing of system components. This will deliver significant cost reductions before any additional impact from technological breakthroughs is considered. For instance, at a manufacturing scale of approximately 0.6 million vehicles per year, the total cost of ownership (TCO)[1] per vehicle will fall by about 45 per cent versus today. 30 percentage points of this cost drop is attributed to manufacturing scale up, 5 percentage points to the fall in low-carbon and/or renewable hydrogen production costs and 10 percentage points to the scale-up of hydrogen refuelling infrastructure deployment.

90 per cent of cost reduction for non-transport applications are from scaling up the supply chain

On average, the cost of hydrogen supplied comprises more than 70 per cent of the TCO for non-transport applications. Delivered low-carbon hydrogen costs are expected to drop sharply over the next decade and will account for up to 90 per cent of the total drop in TCOs from 2020 to 2030 across applications with shorter supply chains. Lower production and distribution costs will both contribute to lowered delivered hydrogen costs.

The cost of low-carbon and/or renewable hydrogen production will fall drastically by up to 60 per cent over the coming decade. This can be attributed to the falling costs of renewable electricity generation, scaling up of electrolyser manufacturing, and development of lower-cost carbon storage facilities.

[1] TCO defines the total costs incurred by a customer over the lifetime of using an application, including capital, operating, and financing costs.

Secondly, distribution costs will drop significantly with higher utilisation of distribution system infrastructure. For instance, with improvements in scale and utilisation, the cost of a single trucking journey of 300 km will drop by 40 per cent. Usage of existing pipeline networks may further slice these costs given sufficient utilisation. Countries with limited gas or renewable electricity sources seeking to increase use of low-cost hydrogen will benefit from lower international shipping costs, making it a viable alternative to local production.

Up to 70 per cent of cost reductions for transport applications are from manufacturing scale-up of end-use equipment

Scaling up manufacturing is another way to reduce costs for many hydrogen applications where costs of end-use equipment comprises a large component of TCO (e.g. fuel cells and tanks in transportation). Large-scale industrialisation of components and vehicle integration, together with lower-cost hydrogen fuel, will halve vehicle TCO in the early stages of scale-up for these and similar applications. The scale in manufacturing of equipment will account for up to 70 per cent of this reduction.

A competitive low-carbon option across 22 applications by 2030

A hydrogen production and distribution system at scale will unlock hydrogen's competitiveness in many applications sooner than previously anticipated. This analysis focused on 35 representative use cases and shows that in 22 of these the TCO will reach parity with other low-carbon alternatives by 2030. These 22 hydrogen applications are material: in total they comprise roughly 15 per cent of global energy consumption. This does not imply that hydrogen will satisfy all this energy demand by 2030, but it does showcase that hydrogen will have a significant role to play as a clean energy vector in the future energy mix. Some examples of applications that become competitive are:

- Commercial vehicles, trains, and long-range transport applications will compete with low-carbon alternatives by 2030 due to lower equipment and refuelling costs.
- Hydrogen boilers will be a competitive low-carbon building heating alternative, especially for existing buildings currently served by natural gas networks.
- In industrial heating, hydrogen will be the only viable option to decarbonise in some cases.
- Hydrogen will play an increasingly systemic role in balancing the power system as hydrogen production costs drop and demand rises.
- Low-carbon and renewable hydrogen will become competitive with grey hydrogen used for industry feedstock today as costs fall and carbon prices rise.

In 9 of the 35 use cases we studied, low-carbon or renewable hydrogen solutions will also be competitive with conventional options by 2030. For example, this is the case for heavy-duty trucks, coaches with long range requirements, and forklifts.

Conclusion and recommendations

Scaling up existing hydrogen technologies will deliver competitive low-carbon solutions across a wide range of applications by 2030 and may even offer competitive low-carbon alternatives to conventional fuels in some segments. Yet, to reach this scale, there is a need for investment, policy alignment, and demand creation.

Need for investment: approximately USD 70 billion required to become competitive

Realising this ambitious vision for hydrogen's role in the future of energy is far from automatic and requires investment above and beyond current commitments. Specifically, the gap between the costs of hydrogen technologies and their lowest cost low-carbon alternative will require funding in order to bring hydrogen to scale and, consequently, cost parity. We have identified several areas where investment until 2030 would make the biggest difference:

- In production, achieving competitive renewable hydrogen from electrolysis requires the deployment of aggregated 70 GW of electrolyser capacity, with an implied cumulative funding gap with grey production of USD 20 billion. Beyond 2030, after reaching economic competitiveness, the cost of renewable hydrogen will further decrease. To initiate the implementation of low-carbon hydrogen from natural gas reforming with carbon capture and storage (CCS), we estimate USD 6 billion is required to fund the additional production costs versus grey hydrogen until 2030, assuming the usage of existing reservoirs.
- In transport, the refuelling and distribution networks required and the cost differential for fuel cells and hydrogen tanks compared with low-carbon alternatives imply an additional required investment of USD 30 billion to cover the economic gap.
- In heating for buildings and industry, financing the cost difference between hydrogen and natural gas and investments to build or repurpose the first gas pipeline networks for hydrogen will amount to USD 17 billion by 2030.

While these figures are sizable, they pale in comparison to global spending on energy. Together they account for less than 5 per cent of annual global energy spend and are on par with the support provided to renewables in Germany of nearly USD 30 billion in 2019. Industry is prepared to invest, but clarity of policy direction to support hydrogen's adoption will accelerate progress. It is all the more critical to act now, as accelerated scale-up will lead to economic deficits to be remedied.

Need for policy alignment: level playing field to accelerate scale-up

Enabling regulations from governments will accelerate industry investments that will ultimately lead to scale. We see six ways in which governments can level the playing field:

- **National strategies.** Governments have a role to play a role in setting national targets, as they have done already through 18 hydrogen roadmaps developed across the globe.
- **Coordination.** Governments are well positioned as neutral conveners of industry stakeholders to mediate potential local investment opportunities.
- **Regulation.** Governments can help remove barriers that may exist to invest in the hydrogen economy today, e.g. by facilitating the process to obtain permits for new refuelling stations and developing internationally consistent regulation to limit market specifities.
- **Standardisation.** Governments can also support industry to coordinate national and international standards, e.g. around pressure levels and safety.
- **Infrastructure.** Governments can choose to invest in the deployment of new infrastructure and re-use, where relevant, of existing networks (e.g. natural gas networks).
- **Incentives.** Finally, governments could decide to apply incentives, e.g. tax breaks or subsidies to encourage the initial acceleration of hydrogen.

Need for market creation: five enablers to establish a market

Even with the right enabling investments and policy support, the choices made at critical inflection points along hydrogen's development will serve to either nurture or suppress the industry's growth. We see five levers through which stakeholders can create demand and establish a market. Together, these can enable hydrogen solutions to reach cost competitiveness in the near future:

- **Reduce market uncertainty.** Stakeholders can look to renewables for inspiration: the creation of long-term offtake agreements removed market risk from installation projects, leaving only technical risk. Another example is facilitating a shift to end-to-end zero-emission fleet logistics solutions that serve captive, recurring demand.
- **Focus on scaling applications and technologies that create the biggest 'improvement-for-investment'.** Critical tipping points – after which costs fall sharply – appear throughout our analyses. For example, scaling fuel cell production from 10,000 to 200,000 units can reduce unit costs by as much as 45 per cent, irrespective of any major technological breakthroughs, and can impact multiple end-use cases. Scaling up to 70 GW of electrolysis will lead to electrolyser costs of less than USD 400 per kW.
- **Seek complementarity in hydrogen solutions.** The development of certain hydrogen solutions can create a virtuous cycle that makes other hydrogen applications viable. For example, leveraging hydrogen infrastructure around airports for on-site refuelling of buses, airport heating, local industry feedstock and potentially in the future, airplane refuelling, will reduce the costs of each individual application.
- **Prioritise increasing utilisation rates in distribution networks.** Moving from 20 to 80 per cent utilisation rates in distribution and refuelling networks can slash distribution costs by up to 70 per cent, which could, for instance, reduce the costs of hydrogen-based home heating by 20 per cent. This will require deploying a minimal threshold of infrastructure to ensure the network serves user demand.
- **Invest in low-carbon and renewable hydrogen production.** Low-cost hydrogen is among the top three cost reductions for every hydrogen application and will be the single most important factor in accelerating the hydrogen economy alongside the created additional demand.

Hydrogen is already scaling up and considerable investments are being made globally. It will provide an important low-carbon option across a wide range of sectors. However, hydrogen's development still requires suitable financial, infrastructural and policy support to allow it to achieve a wide deployment and scale-up through commercial projects. Given the urgency of the global decarbonisation challenge, society must capitalise on hydrogen's advantages now. The hydrogen industry can help enable the energy transition to a net-zero world, and this report clearly identifies the cost trajectories of its many applications, presenting numerous opportunities.

A **comprehensive cost perspective** on hydrogen applications and technologies

35 applications

40+ hydrogen technologies

Modelled in detail to develop the pathway to hydrogen competitiveness

Introduction and methodology

Hydrogen is accelerating

Policy and economic forces are converging to create unprecedented momentum in the hydrogen sector, paving the way for rapid deployment of and investment in hydrogen technologies. A growing number of societal actors – from youth activists to scientists to concerned consumers – are pushing for stronger policy action to more drastically limit carbon emissions. Climate change requires urgent attention: if we continue to emit CO_2 at current levels, we have only ten years remaining in the global carbon budget before we breach the 1.5-degree Celsius threshold, emphasising the need for immediate action.

Governments are responding with increasingly ambitious decarbonisation targets. At the time of the 2019 UN Climate Summit, 66 countries had announced their intent to meet net-zero carbon emissions targets by 2050. In the EU, regulation includes potential fines for failure to meet targets, and a Green Deal was recently announced to support the net-zero emissions target. In the US, 25 states formed the bipartisan United States Climate Alliance with a collective commitment to reduce greenhouse gas (GHG) emissions by at least 26 to 28 per cent below 2005 levels by 2025.[2] China has made considerable progress towards its climate policy goals of reaching peak emissions by 2030 and meeting its target of 20 per cent of primary energy demand from non-fossil fuel sources with continued investment in sustainable technologies.[3]

Unlike previous eras in hydrogen's development, the renewed attention on hydrogen is strengthened by a realisation that the use of hydrogen will be critical if we are to meet the climate objectives. Governments are recognising hydrogen's ability to decarbonise sectors that are otherwise impossible or difficult to abate – such as logistics, industrial heating and industry feedstock – and its role in energy security. Meanwhile, industry leaders across the automotive, chemicals, oil and gas and heating sectors look to low-carbon and renewable hydrogen as a serious alternative to reach their increasingly robust sustainability objectives.

This renewed attention also comes as the key cost drivers of clean hydrogen have seen a sharp improvement. For instance, electrolysis fed with renewable electricity – the most common production method to produce 'renewable hydrogen' – has become 60 per cent more affordable as low-carbon and renewable electricity prices have dropped and electrolysis capex has fallen. The cost of solar and wind power, the largest driver of renewable hydrogen production costs, has seen an 80 per cent decrease over the past decade. Recent subsidy-free offshore wind auctions in Europe and bids close to or below USD 20 per megawatt hour (MWh) for solar photovoltaics (PV) and onshore wind plants have been seen. This downward cost trajectory for renewables should continue, with 14 times more solar capacity projected to become available in 2030 than was previously estimated. At the same time, electrolysis capacity has also started to accelerate, with at least 55 times more capacity expected by 2025 versus 2015, which will result in a similar cost drop in electrolysis capex.

Building on this momentum, governments have implemented a growing number of tangible policies promoting hydrogen. To date, 18 governments, whose economies account for 70 per cent of global GDP, have developed detailed strategies for deploying hydrogen energy solutions. This includes recent announcements from the coalition of governments forming the Energy Ministerial to target the global deployment of 10 million fuel cell electric vehicles (FCEVs) by 2030 – a fourfold increase of the target over the last two years – and projects across China, Japan, the US, and South Korea to build 10,000 hydrogen refuelling stations by 2030.

[2] US Climate Alliance (2019).
[3] Qi, Y., Stern, N., He, J., Lu, J., King, D., Liu, T., Wu, T. (2018).

Meanwhile, as governments develop specific hydrogen strategies, growing industry associations provide further evidence that something truly different is happening with hydrogen. More industry players are recognising hydrogen's versatility and falling cost, enabling investments in a growing range of sectors. One such global initiative, the Hydrogen Council, has seen its membership grow to 60 companies. This is up from 13 at its founding in 2017, representing a combined market cap of USD 1.7 trillion with combined revenues of over USD 2.6 trillion and close to 4.2 million jobs around the world.

Over the same period, stakeholders have proposed more than 30 major investments globally in segments such as heavy-duty trucking, rail, and steel production from low-carbon or renewable hydrogen. Exhibit 1 lists all the drivers and indicators for hydrogen's growing momentum.

Exhibit 1 | Drivers and indicators of hydrogen's momentum

Drivers of renewed interest in hydrogen

Stronger push to limit carbon emissions

10
Years remaining in the global carbon budget to achieve the 1.5°C goal

66
Countries that have announced net-zero emissions as a target by 2050

Falling costs of renewables and hydrogen technologies

80%
Decrease in global average renewable energy prices since 2010

55x
Growth in electrolysis capacity by 2025 vs. 2015

Indicators of hydrogen's growing momentum

Strategic push in national roadmaps

70%
Share of global GDP linked to hydrogen country roadmaps to date[1]

10 m
2030 target deployment of FCEVs announced at the Energy Ministerial in Japan

Industry alliances and momentum growing

60
Members of the Hydrogen Council today, up from 13 members in 2017

30+
Major investments announced[2] globally since 2017, in new segments, e.g. heavy duty and rail

1. Based on 18 country roadmaps announced as of publication
2. Not exhaustive

The need for a hydrogen cost perspective

The Hydrogen Council's previous report, 'Hydrogen Scaling Up', showed the critical role hydrogen could play in global industrial decarbonisation. While interest in hydrogen has been rising since then, it has not led to the required investments along the value chain. New projects have been announced, but most are not yet sanctioned, likely due to the lack of suitable policy and regulatory frameworks. There are relatively few hydrogen projects already at scale from which stakeholders can gauge hydrogen's near- and long-term economic viability, and industry readiness varies significantly by sub-segment, company and region. Visibility on further cost reduction, hydrogen competitiveness and the scale of required investments – the 'economic gap' that must be bridged in order to reach the scale at which hydrogen is competitive – remain unclear to many.

This report aims to address this information gap by providing the first industry-derived, holistic view of hydrogen's cost base and its path to competitiveness across all scalable applications. It provides an evidence base on the path to cost competitiveness for 40 hydrogen technologies used in 35 applications. For policymakers, such a perspective provides firm ground on which to base priority investments and non-financial support that will unlock the economic value of hydrogen. For decision-makers in industry, it offers a holistic picture of value chain cost dynamics and inter-relationships, allowing them to put their own efforts into a broader perspective.

The report is divided in four parts: Chapter 1 presents an overview of hydrogen's path to competitiveness, including key cost-reduction drivers across a wide range of applications as compared to alternative low-carbon and conventional technologies. The assessment reflects 25,000 data points from over 30 global companies in and close to the Hydrogen Council (listed in Exhibit 2), aggregated and processed using a rigorous clean team approach and covering more than 40 elements along hydrogen value chains, from production to conversion to distribution and end use.

Exhibit 2 | Report contributors

Hydrogen Council Steering Group

3M, AIRBUS, Air Liquide, Air Products, ALSTOM, AngloAmerican, BMW GROUP, BOSCH Invented for life, bp, 国家能源集团 CHN ENERGY, Cummins, DAIMLER, EDF, ENGIE, equinor, faurecia inspiring mobility, GM, Great Wall, HONDA, HYUNDAI, Iwatani, Johnson Matthey Inspiring science, enhancing life, JXTG Nippon Oil & Energy, Kawasaki, KOGAS, Linde, PLASTIC OMNIUM, Shell, SINOPEC, thyssenkrupp, TOTAL, TOYOTA, WEICHAI 潍柴

Analytical support

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E4tech

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Chapter 2 details the role hydrogen production and distribution costs play in hydrogen's competitiveness across applications. Cost trajectories for various technologies were estimated for key regions, including Europe, the US, China, Japan, and Korea.

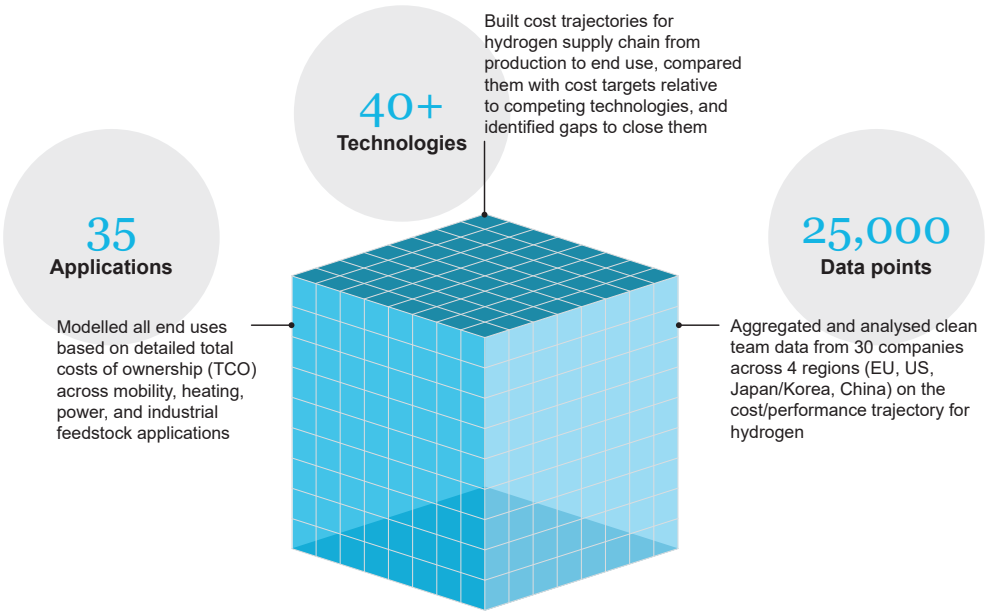
Chapter 3 examines the TCO trajectories and requisite deployed volumes required to achieve the expected cost reductions for several applications in each end-use segment: transportation, heating and power, and industry feedstock. It provides insights into the decision criteria, fundamental competitiveness, and trade-offs for deploying hydrogen over competing technologies. While the report focuses on assessing cost competitiveness, there may be other non-economic factors that stakeholders will consider when comparing technologies, such as the decarbonisation potential and interdependencies between applications.

Chapter 4 explores the implications of the findings on the different cost trajectories. Scaling up existing hydrogen technologies will deliver competitive low-carbon solutions across a wide range of applications by 2030. Yet, to reach this scale, there is a need for investment, policy alignment and demand. The report estimates the economic gap that must be bridged for hydrogen to break even with competing technologies. It goes on to provide recommendations on critical policy areas and lastly, offers five insights for government, industry, and investors to create a hydrogen market.

Methodology for evaluating hydrogen's cost competitiveness

Before presenting the results, some explanation of the methodological approach to the analysis is provided. The report's analysis compares the TCO of low-carbon and renewable hydrogen applications against specific low-carbon and conventional alternatives, e.g. fuel cell electric vehicles versus battery electric vehicles (BEVs) and diesel vehicles. In evaluating applications on which to focus, any hydrogen and other low-carbon solutions that are not realistically scalable were excluded. Exhibit 3 shows the key metrics used in the analysis to highlight the main building blocks of the approach.

Exhibit 3 | Approach to building hydrogen costs perspective



To start, 35 applications were selected across four segments where hydrogen could play a role – in transportation, heat and power for buildings, heat and power for industry, and industry feedstock. Within each of these applications, specific, representative use cases were identified for analysis – such as hydrogen boilers for existing residential properties in Europe – to assess the cases in which hydrogen is competitive and understand what drives its competitiveness. Additionally, more than 40 technologies for hydrogen production and distribution were modelled, covering a range of production methods, conversion steps (e.g. compression, liquefaction), and distribution pathways.

For each hydrogen application and its competing alternatives, a comprehensive TCO trajectory was developed to detail the relevant cost components, cost-reduction drivers were determined, and the break-even point was identified between competing solutions. This was done via an independent third-party clean team who collected, aggregated and processed data from participating Hydrogen Council members, producing anonymised cost estimates by application. In a limited number of use cases where insufficient internal data were available, such as in developing the cost trajectory for aviation synfuels, external projections were used. The findings were then tested with insights from an independent group of experts in government and academia, including Dr. Alan Finkel, Australia's Chief Scientist; Dr. Timur Gül, Head Energy Technology Policy Division at the International Energy Agency; Tom Heller, Chairman of the Climate Policy Initiative; Dr. Noé van Hulst, Hydrogen Envoy at the Netherlands Ministry of Economic Affairs & Climate Policy; and Lord Turner, Chair of the Energy Transitions Commission.

In order to ensure consistent cost projections by the participating companies, we provided specific volume ramp-ups by technology and application as an input. We broadly used the volume ramp-ups from our 2017 'Hydrogen Scaling Up' report but adjusted for certain applications, e.g. passenger vehicles, to arrive at more probable cost trajectories. The scale up assumptions do not represent a forecast of actual volumes, but the trajectory for road transport is supported by promising signs of an ambitious deployment as addressed in the "Ramp-up of hydrogen transportation globally" sidebar. The assumptions are based on the required low-carbon and renewable hydrogen production volume scales to meet 18 per cent of global final energy demand by 2050, to help limit the rise in global temperatures to well below 2°C.

Ramp-up of hydrogen transportation globally

The ramp-up curve for hydrogen applications is still uncertain, and it remains to be seen how volumes will develop. However, the situation is promising as illustrated by hydrogen transport applications: 18 countries have announced ambitious roadmaps and a number of private sector players are working on developing the hydrogen economy through initiatives such as H2 Mobility Germany or H2 Mobility Japan.

The roll-out of HRS networks has started and globally there are more than 400 stations operating, with approximately 200 more planned in 2020. Countries such as Germany have set ambitious targets announcing that 400 stations will be built until 2023, while South Korea has announced 310 stations by 2022.

The Energy Ministerial in 2019 launched a target of 10 million fuel cell vehicles, 10 thousand refuelling stations, in the 10 years until 2030 – the "10-10-10" target. This is in line with the required vehicle fleet volume to reach the 2-degree Celsius target as described in our 'Scaling Up' report, where we found that approximately 3 per cent of global vehicle sales in 2030 should be hydrogen-fuelled, and as much as 36 per cent in 2050.

To reach this target, fuel cell vehicle production will need to increase radically. We find that reaching a production level of approximately 1 million vehicles per annum would bring the majority of vehicle segments to competitiveness, paving the way towards a cost-competitive low-carbon vehicle park as well as the "10-10-10" target.

In general, hydrogen costs were estimated on the basis of an average of natural gas reforming and CCS and renewable hydrogen from renewable power generation and electrolysis. However, for several applications, a specific production method was assumed in order to better understand likely variations between regions, i.e. the EU, the US, Japan, and China. For carbon-emitting applications, the implicit cost of carbon was assumed to increase from USD 30 per ton in 2020 to USD 50 per ton in 2030. These are applied throughout the analyses, except where a carbon cost sensitivity analysis was performed. All financial figures are in US dollars (USD) and refer to global averages unless otherwise indicated.

Hydrogen cost **competitiveness is closer** than previously thought

22

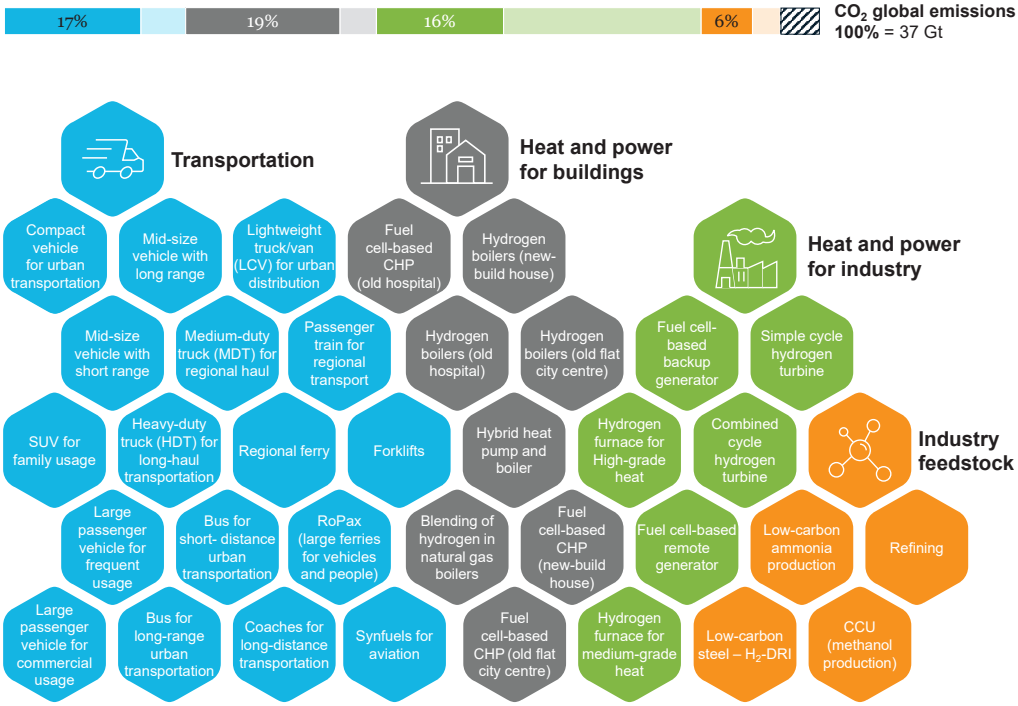
Hydrogen applications may become the most cost-competitive low-carbon solution in 2030

1 | Cost perspective: hydrogen is already surprisingly competitive as a low-carbon option

Overview of cost-competitiveness by application

This report's key finding is that a hydrogen supply and distribution system at scale will unlock hydrogen's competitiveness in many applications sooner than previously anticipated. This report covers 35 hydrogen applications in transport, buildings, industry heat and industry feedstock (Exhibit 4). It includes both new and existing applications currently responsible for 60 per cent of the world's energy- and process-related emissions. Our scope focuses on applications for which hydrogen is best suited, although this analysis does not include all of such applications.

Exhibit 4 | Overview of hydrogen applications



In addition, hydrogen can also be used in, e.g.

Mobility: Container ships, tankers, tractors, container ships, motorbikes, tractors, off-road applications, fuel cell airplanes.

Other: Auxiliary power units, large scale CHP for industry, mining equipment, metals processing (non-DRI steel), etc..

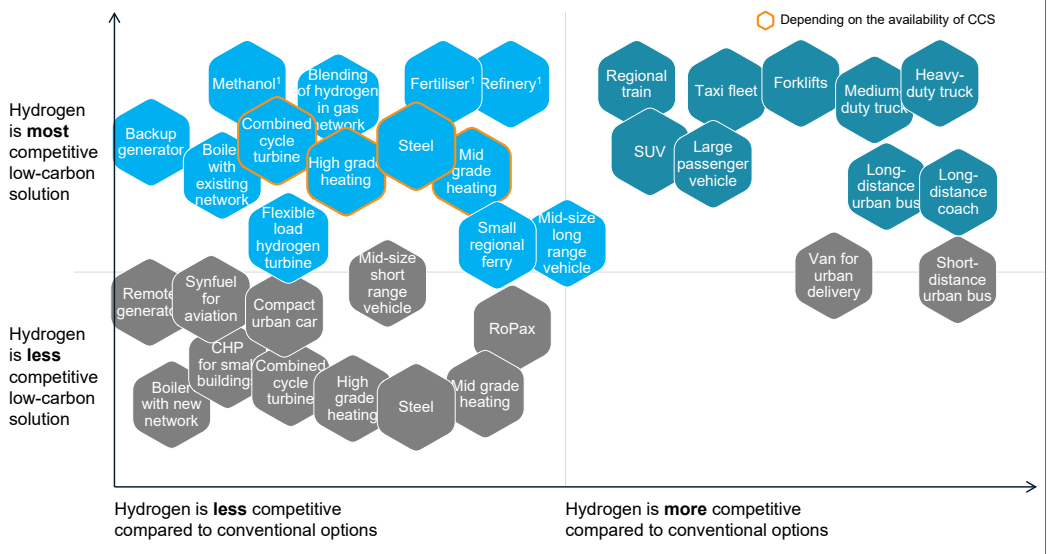
For each application, we assessed the TCO for a low-carbon hydrogen solution from 2020 to 2050. For most applications, we then compared these costs with other low-carbon solutions (e.g. battery vehicles, heat pumps) and conventional technologies (e.g. diesel-powered vehicles, gas boilers). In some applications, hydrogen is practically the only low-carbon solution – for example, in feedstock applications such as ammonia production and hydrocracking in refining, low-carbon and renewable hydrogen competes with 'grey' hydrogen produced from unabated fossil resources. In such cases, we only compared to conventional alternatives and between different hydrogen sources.

We identified 22 applications where hydrogen can become a cost-competitive low-carbon solution before 2030 under the right conditions (Exhibit 5) and assumed scale-up cited before. Examples of these include long-distance transport applications and regional trains, which are highly competitive with low-carbon alternatives, as indicated by their position high on the y-axis of Exhibit 5. These 22 hydrogen applications are material: in total, they account for up to 15 per cent of global energy consumption (17,500 TWh). This does not imply that hydrogen will satisfy all this energy demand by 2030, but it does showcase that hydrogen is expected to have a significant role to play as a clean energy vector in the future energy mix.

In four of the reviewed applications, the competitiveness of hydrogen depends on the availability of CCS. If CCS resources for those applications are not available, hydrogen offers the only way to decarbonise the application. Examples include combined cycle turbines, steel production, high-grade heating for cement and medium-grade heating for plastics production.

Compared with conventional alternatives, we find several applications to be highly competitive at scale to both low-carbon and conventional alternatives, requiring zero- or low-carbon prices for hydrogen to break even, as indicated by their position at the right of the x-axis in Exhibit 5. This is true for nine applications, including trucks, trains, long-range passenger vehicles, and long-distance buses. Conversely, for several other applications, including use in turbines, industry feedstock, or synthetic fuel for aviation, a carbon tax of at least USD 100 per ton of carbon dioxide equivalent (CO_2e) would be required to make hydrogen competitive with conventional fuels.

Exhibit 5 | Competitiveness of hydrogen applications versus low-carbon and conventional alternatives



1. Hydrogen is the only alternative and low-carbon/renewable hydrogen competing with grey (optimal renewable or low-carbon shown)

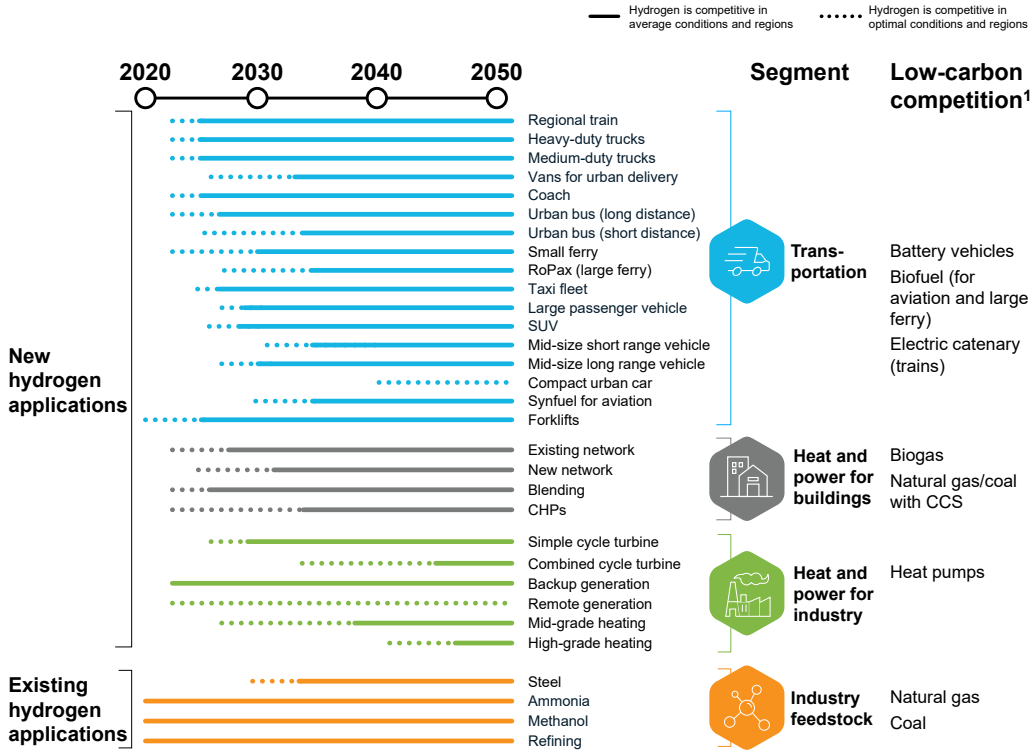
Timeline for cost competitiveness

Exhibit 5 provides a static view of the industry in 2030, but the cost competitiveness of hydrogen applications will improve with scale over time. The timeline in Exhibit 6 builds on the hydrogen deployment scenario presented in our 2017 'Hydrogen Scaling Up' study. It shows the point at which hydrogen becomes the most cost-competitive low-carbon solution for each application. For industry feedstock applications, the logical conclusion is that industry has already passed the break-even point, since no other low-carbon alternative to using low-carbon or renewable hydrogen exists.

The break-even timing depends heavily on the region, each of which has its own energy prices, infrastructure readiness, and available policy framework to support scale-up and regulation. The dashes in the exhibit show when an application becomes cost competitive in all regions analyzed – for example, taxi fleets first become competitive with full BEV fleets around 2023, assuming optimal hydrogen costs, but reach cost parity within two to three years later across all regions.

We compared the hydrogen applications with at least one low-carbon alternative. For example, for road transport applications, we assessed BEVs, while for space heating we considered heat pumps as the low-carbon alternative. The competing low-carbon solutions selected must qualify as fully low-carbon, but may include CCS where relevant (assuming a capture rate of 90 per cent or higher). They must also be scalable and able to achieve full decarbonisation of a segment. Other solutions that qualify as partially low-carbon are not considered as alternatives. For example, using a hybrid heat pump and a natural gas boiler can support the pathway to decarbonisation, but is not considered here as it is not fully low carbon.

Exhibit 6 | Cost competitiveness trajectories of hydrogen applications



1. In some cases hydrogen may be the only realistic alternative, e.g. for long-range heavy-duty transport and industrial zones without access to CCS

From 2020 to 2025. In the short term, hydrogen could become competitive in transportation, particularly for large vehicles with long ranges (i.e. trains, trucks, coaches, and taxi fleets) and forklifts. For these applications, the competing technologies, namely BEVs, are too costly to be viable alternatives for real economic use cases. Heating with hydrogen can become more prevalent when it co-opts existing gas networks. Hydrogen is by default the most competitive alternative to decarbonise industry feedstock, as these processes require hydrogen. All applications will struggle to compete against conventional alternatives on a cost basis in the short term, given the current higher cost of hydrogen technology and limited infrastructure and scale.

By 2030. With the costs of hydrogen production and distribution falling, many more applications should become competitive against low-carbon alternatives by 2030. Examples include most road transport applications except short-range use cases (e.g. compact cars and short-distance buses), simple cycle hydrogen turbines for peak power, hydrogen boilers, and industry heating.

Long term. By 2050, most of the assessed hydrogen applications considered can become competitive against low-carbon alternatives. In our 2-degree Celsius scenario, total world CO_2 emissions will need to be more than 90 per cent lower than today by 2050 – an outcome only achievable by applying low-carbon hydrogen solutions in tandem with other solutions, such as electrification and carbon sequestration.

Hydrogen competitiveness depends greatly on the region. It will play a critical role in decarbonising hard-to-abate industry segments, especially when no nearby direct use clean power alternatives or CCS are available, or prove more expensive. These segments may include long-haul transport, industrial feedstock, power generation from turbines, and industrial heating. Where low-carbon options exist for these segments, they typically require either availability of CO_2 storage or significant amounts of biomass.

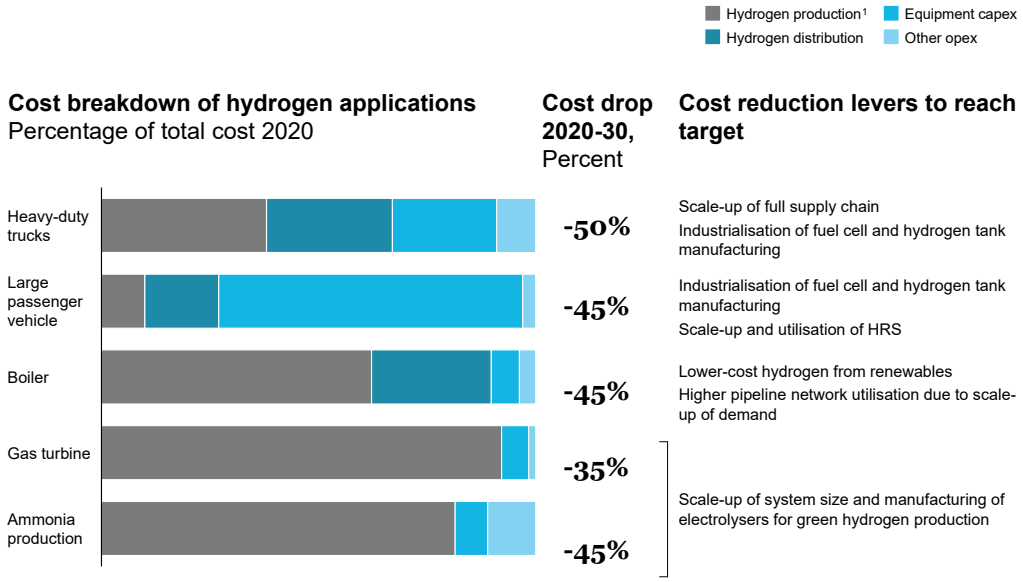
Local conditions will influence competitiveness rankings. Regions with access to abundant low-cost clean power, biomass or CO_2 storage will present tougher conditions for hydrogen, especially where direct electrification is an option. For example, heat pumps may work better in some locations compared to building a full hydrogen pipeline network if there is a strong electricity grid, good access to clean electricity and an absence of an existing natural gas network. The same applies to remote power generation where abundant local renewable energy may be preferred over hydrogen generators. In regions with easy access to carbon storage, hydrogen will also face tough competition whenever fossil fuels with CCS are the alternative, like industrial heating or steel production.

Drivers of cost competitiveness

Application TCOs typically comprise hydrogen production, distribution and end-use equipment costs. The degree to which each of these elements impact the TCO of an applications differs by application (Exhibit 7). For non-transport applications, more than 80 per cent of of the TCO is driven by hydrogen production and distribution. In contrast, end use equipment costs may comprise up to 70 per cent of transport application TCOs, depending on the usage profile.

In the following sections, we consider each of these factors. We first consider the importance and implications of production scale on equipment capex. We then explore the impact of consumption volume on the utilisation of distribution infrastructure. Finally, we showcase the importance of scale in reducing hydrogen production costs.

Exhibit 7 | Drivers of hydrogen's cost competitiveness



1. Assumes 50/50 blend of low-carbon and average renewable hydrogen

Implications of scale on equipment costs

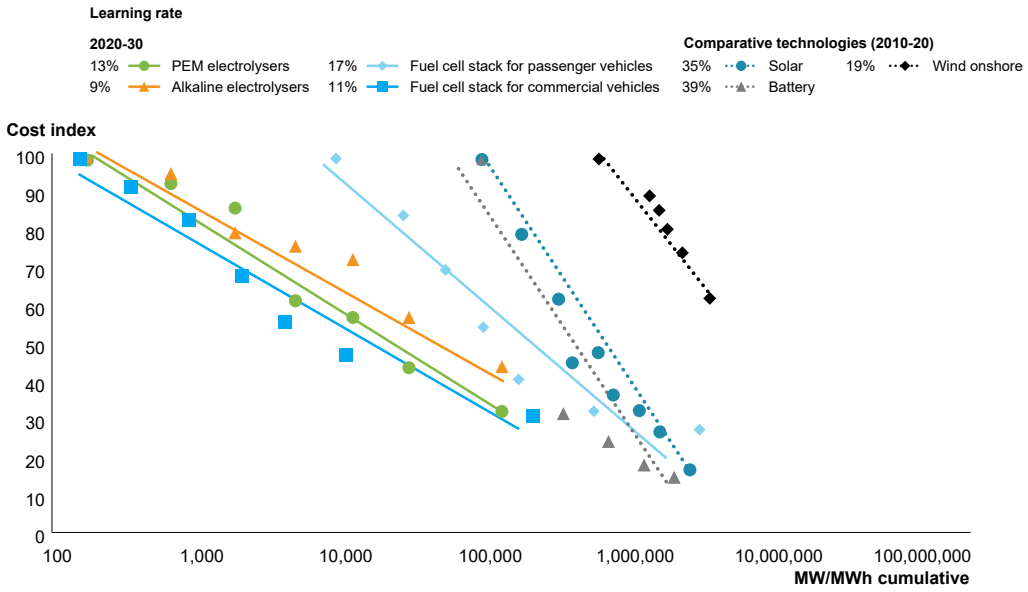
Scale will reduce equipment costs significantly across the hydrogen value chain. Hydrogen technologies currently have niche status, and there is significant potential for both achieving economies of scale in the manufacturing process and improving the technology further. In solar and wind power, for example, each doubling of cumulative production in the past led to cost reductions of 19 to 35 per cent. Exhibit 8 shows the estimated learning rates for electrolysers and fuel cells compared to solar, onshore wind and batteries.

We estimate that fuel cell stacks for passenger vehicles will exhibit learning rates of about 17 per cent in the near future. The learning rates for commercial vehicles are lower, at roughly 11 per cent, primarily due to the lower volume of vehicles, but will still benefit from scale-up in other segments. Electrolyser learning rates are about 9 per cent and 13 per cent, respectively, for alkaline and PEM technology. Learning rate estimates for PEM are slightly higher, as this technology is less mature and therefore has higher cost-reduction potential. All of these estimates are independent of synergies between the technologies, which could further drive up the learning rates. For instance, the PEM electrolyser manufacturing may benefit from improvements in the PEM fuel cell production.

These cost reductions may seem aggressive at first, and uncertainties exist in both scale of deployment and technology. However, when comparing the cost trajectories with other 'new' technologies such as solar panels and lithium-ion batteries, both with historical learning rates above 30 per cent, they appear conservative, and we may in fact expect further upside.

Exhibit 8 | Learning rates for hydrogen applications

Capex development of selected technologies over total cumulative production
Indexed to 2020 values (2010 for comparative technologies)[1]



1. Installed base: assuming 50/50 split of electrolysers volume with 50-75% utilisation; assuming 115 kW for PV, 250 kW for buses and 300 kW for trucks; LCOE used for solar cost; batteries in MWh

SOURCE: McKinsey; IRENA; BNEF; Ruffini & Wei (2018) (learning rates); DoE

Learning rates are highest for emerging technologies (PEM) and high volume FC for passenger vehicles.

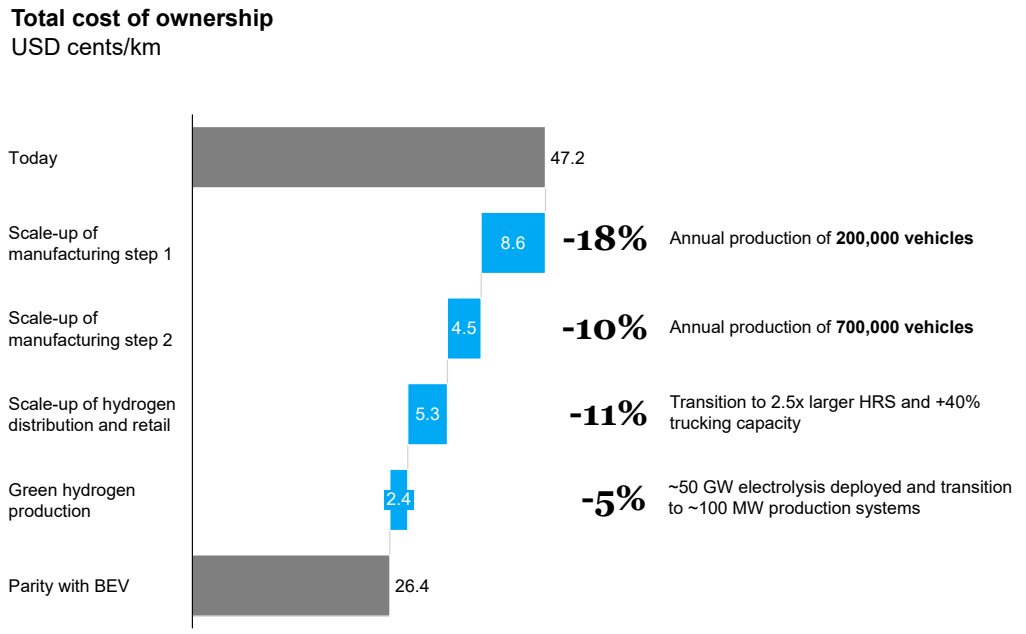
Learning rates for tanks are ~10-13%, somewhat lower than for fuel cells due to higher materials share of cost.

Implications of scale on utilisation and distribution costs

Beyond reductions in equipment costs, a scale-up in hydrogen usage will also lead to improved utilisation of capex. This point can be illustrated with reference to passenger car TCO. Achieving cost reductions for fuel cell vehicles requires the scale-up of both manufacturing of components as discussed above (e.g. fuel cells and hydrogen tanks) and the total hydrogen supply chain.

The TCO for large passenger vehicles could decline by about 45 per cent by 2030, as shown in Exhibit 9, driven by three main factors: lower-cost vehicle capex, lower-cost distribution and retail of hydrogen, and lower-cost hydrogen production. These cost reductions are vital for reaching cost parity with BEVs.

Exhibit 9 | Cost reduction for large passenger vehicles



Insight

Majority of cost reduction in vehicle capex comes from scaling up to 200k annual production; to reach fully parity with full battery vehicles 600k annual production volumes are required.

As per the previous discussion on learning rates, vehicle capex reduction can make FCEVs competitive with other technologies. Today, fuel cell vehicles carry an approximately 70 per cent higher cost than BEVs in the large passenger vehicle segment with the same range. Reducing the cost of the car itself is thus key to securing cost competitiveness. These reductions are achievable. Our findings show that the cost of fuel cells is a 'step function'. An annual global production volume of only 200,000 vehicles could reduce the total cost of the fuel cell by about 45 per cent, resulting in a 18 per cent reduction in the TCO of the vehicle. A further increase to 600,000 production volume would reduce TCO by another 10 percentage points, corresponding to about 70 per cent cost reduction for the fuel cell itself.

Beyond the cost of equipment, the cost of hydrogen supplied is a key cost driver – particularly supply chain costs. In fact, hydrogen distribution and retail costs represent the most significant part of the cost of hydrogen faced by the large passenger vehicle end user, accounting for about 60 per cent of the outlay. Scaling up the value chain can significantly reduce this amount, resulting in an 11 per cent cost drop for a large passenger vehicle TCO. Three major factors are behind this cost reduction: the utilisation of HRS, a transition to larger stations, and reliance on high-capacity logistics (e.g. higher pressure trucks, pipelines) with higher utilisation.

A more efficient use of infrastructure would distribute costs across more users. For instance, an increase from 60 to 80 per cent utilisation of hydrogen refuelling stations would reduce the cost contribution for the station by about 25 per cent. Operators can achieve high infrastructure utilisation and corresponding lower costs earlier on by developing supply infrastructure in lockstep with demand, e.g. for vehicle fleets.

Likewise, going from small stations with 200 kg per day capacity to larger stations with 1,000 kg per day would reduce the cost contribution from hydrogen refuelling station by about 70 per cent, with further decreases projected as deployment increases and the station's investment and operational costs decline.

Implications of scale on hydrogen production cost

The final cost-reduction driver for the TCO of fuel cell large vehicles beyond scale in the supply chain is scale in production. This will lead to lower costs of hydrogen supplied. Today, renewable hydrogen from electrolysis costs approximately USD 6 per kg. Reducing this to around USD 2.60 per kg would help to achieve cost parity. This could drive down TCO by another 5 per cent.

As the large passenger vehicle example illustrates, hydrogen production costs play an important role in the overall hydrogen equation. The cost of hydrogen production is even more important for all non-transport application that are fuel- and feedstock-intense such as gas turbines, boilers, and ammonia production. Some transport applications that are more fuel-intense, like heavy-duty trucking, have a similar sensitivity to hydrogen production costs. More generally, sensitivity to hydrogen costs increases the shorter the supply chain is.

Since hydrogen production cost matters greatly to competitiveness in most segments, it is important to understand its cost trajectory. Low-carbon and renewable hydrogen costs will likely decline significantly in the coming years. In the short term, low-carbon hydrogen from reforming plus CCS offers the lowest cost in regions with access to w storage. Volumes of low-carbon hydrogen should increase to about 12 million tons of hydrogen per year, with costs of about USD 1 to 2 per kg by 2030. Cost reductions of approximately 5 to 10 per cent should occur due to lower-cost CCS. Limited improvement potential exists since natural gas reforming is a well-established technology today.

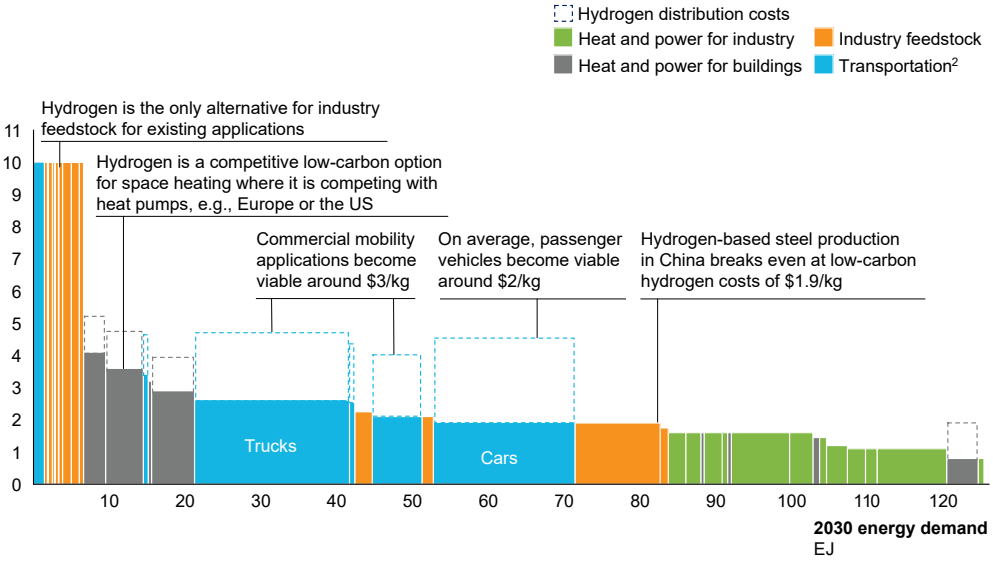
Within five to ten years – driven by strong reductions in electrolyser capex of about 70 to 80 per cent and falling renewables' levelised costs of energy (LCOE) – renewable hydrogen costs could drop to about USD 1 to 1.50 per kg in optimal locations, and roughly USD 2 to 3 per kg under average conditions. Achieving these electrolyser cost targets of around USD 400 per kW would require deployment of about 70 GW of electrolysis capacity, assuming a learning rate of 9 to 13 per cent.

Hydrogen production break-even costs by application

We estimated the break-even levels where hydrogen applications become competitive in comparison to low-carbon alternatives. We assessed four main regions, namely China, the US, the EU, and Japan/Korea, in detail. Exhibit 10 shows the cost of hydrogen at which each use case becomes cost competitive with the low-carbon alternative in 2030, and how much energy demand that theoretically accounts for. The transportation and distributed heating segments require specific infrastructure, and we have thus considered the corresponding costs separately when calculating the break-even point.

Exhibit 10 | Cost curve for hydrogen production across segments and regions

Breakeven hydrogen costs at which hydrogen application becomes competitive against low-carbon alternative in a given segment
USD/kg



1. Regions assessed are the US, China, Japan/Korea, and Europe
2. Transportation segments breakeven calculated as weighted average

SOURCE: McKinsey; IHS; expert interviews; DoE; IEA

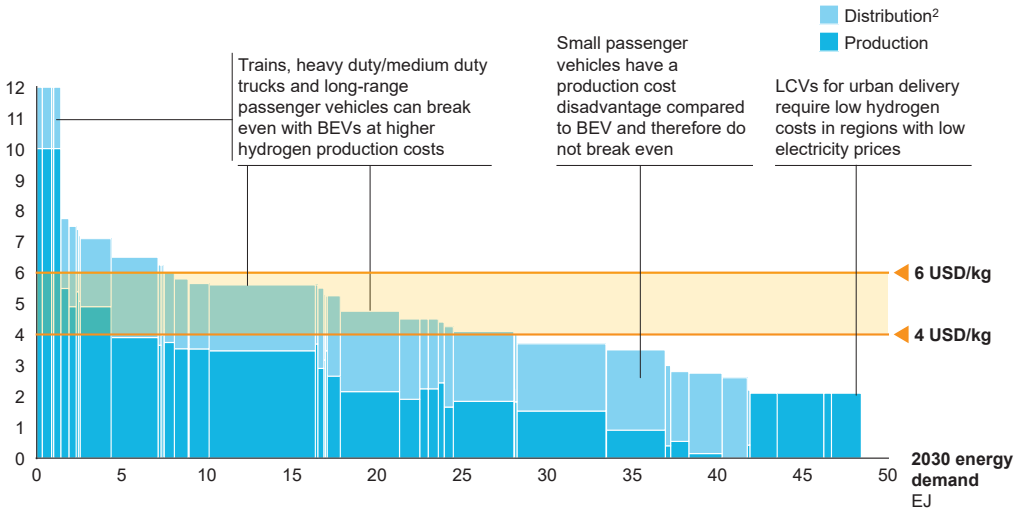
We find that hydrogen can unlock approximately 8 per cent of global energy demand with a hydrogen production cost of USD 2.50 per kg, while a cost of USD 1.80 per kg would unlock as much as roughly 15 per cent of global energy demand by 2030. This does not imply that hydrogen will satisfy all of this energy demand by 2030, but it does showcase that hydrogen will have a significant role to play as a clean energy vector in the future energy mix. As mentioned in our prior report, we expect hydrogen may fulfil about 18 per cent of final energy demand by 2050.

It is important to differentiate between applications that allow for CCS on-site, e.g. power generation, industrial heating, and steel production, and applications where direct CCS is not an option, such as domestic heating. For power and industry applications where CCS is feasible and CO_2 storage is accessible, break-even hydrogen cost falls below USD 1.5 per kg. This is particularly true in regions where conventional fuels such as natural gas and coal are abundant and low cost, such as the US. For distributed usage like building heating, where on-site CCS is not an option, hydrogen prices of about USD 3 to 4 per kg would break even, with heat pumps as the decarbonisation alternative. For these applications, low-carbon hydrogen with centralised CCS or renewable hydrogen from electrolysis will have clear benefits.

Mobility stands out among the other segments, and is shown in Exhibit 10 as a weighted average across regions and sub-segments, e.g. heavy-duty trucks and delivery vans are aggregated to ‘trucks’. We break these segments out in Exhibit 11 below to provide more detail. Our findings show that hydrogen costs can be higher for long-range mobility segments without compromising competitiveness with the best low-carbon alternative, BEVs. Mobility applications are generally less sensitive to hydrogen production costs than other segments, due to longer hydrogen supply chains and higher cost contribution of equipment. Consequently, in transportation, the hydrogen industry can unlock a growing share of demand even at hydrogen production cost levels of above USD 2 per kg before supply chain and refuelling costs.

Exhibit 11 | Cost curve for hydrogen for transportation across segments and regions

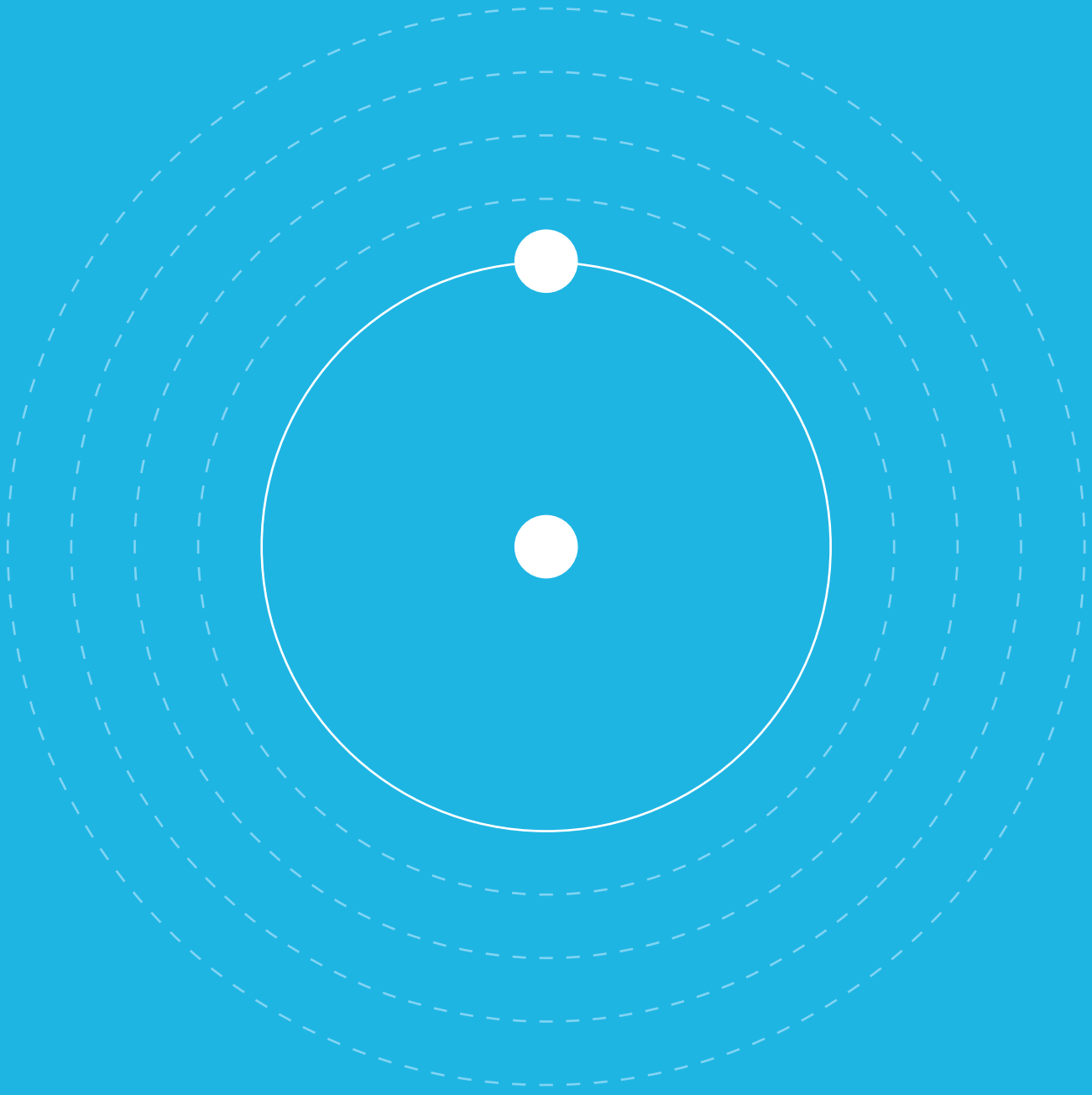
Breakeven hydrogen costs at which hydrogen mobility applications becomes competitive against low-carbon alternative in a given segment in focus regions[1]
USD/kg at nozzle



1. Regions assessed are the US, China, Japan/Korea, and Europe
2. No distribution costs for aviation as it can be distributed as liquid fuel

SOURCE: McKinsey; IHS; expert interviews; DoE

We find that hydrogen can meet a large share of the mobility energy demand by 2030. Even with hydrogen costs at the pump of USD 6 per kg – including production, distribution, and retail – the fuel can meet about 15 per cent of transport energy demand cost competitively by 2030. We expect this cost profile to become viable in most regions and use cases by 2030. If costs were USD 4 per kg at the nozzle, hydrogen could even meet more than 50 per cent of the mobility sector's energy demand. Trucks, long-distance buses and large passenger vehicles are particularly competitive, as the cost of batteries required to secure the necessary range is very high for the battery alternatives.



Scaling up the full **hydrogen value chain** is the key to unlocking potential applications

60%

Cost reduction of hydrogen by 2030 for the end user

2 | Hydrogen production and distribution

Reducing hydrogen production costs will play a disproportionate role in unlocking the cost competitiveness of all hydrogen applications. The cost of producing clean hydrogen should drop by up to 60 per cent over the coming decade, with the optimal production option highly dependent on the region. For example, where natural gas is cheap and CO_2 storage is available, reforming and CCS offers a low-cost, at-scale source of production.

In addition to lower hydrogen production costs, distributed applications like mobility will benefit from reductions in delivery costs. With increasing utilisation and scale, hydrogen delivery costs should decline by up to 70 per cent over the next decade, making it possible for hydrogen to be dispensed at about USD 4.50 to 6 per kg.

In the following sections, findings on hydrogen production cost development and the most important cost-reduction factors are discussed. Developments in the cost of hydrogen distribution for different use cases are also explored.

Hydrogen production today

Today, most hydrogen comes from fossil fuels (grey hydrogen). Two primary options exist for producing hydrogen with lower carbon intensity: either via electrolysis powered by low-carbon electricity or natural gas reforming and coal gasification with CCS. For details on each type of production, see the sidebar: 'Low-carbon hydrogen production'.

Currently, the high production cost for less carbon-intense hydrogen – for instance about USD 6 per kg for renewable hydrogen from electrolysis – is hindering adoption. In total, less than 5 per cent of hydrogen volume today comes from low-carbon sources. However, recent cost reductions in renewable energy generation (for renewable hydrogen from electrolysis) and development in CCS (with natural gas reforming) are now paving the way for a growing number of low-carbon hydrogen applications. In renewable hydrogen production, for example, a total of more than 1 GW of electrolyser capacity has already been announced – a staggering 50-fold increase compared with 2015.

Low-carbon and renewable hydrogen production

Most hydrogen today is produced from fossil fuels and emits carbon (grey hydrogen). There are numerous options for producing low-carbon and renewable hydrogen. This report focuses on the two main options: reforming natural gas or coal and capturing the emitted carbon, and electrolysis using low-carbon power as an input. Biomass gasification is another promising source of low-carbon hydrogen production; however, it does not currently contribute a meaningfully large share of global supply.[4]

Two main technologies can produce hydrogen from electrolysis in combination with renewable electricity: proton-exchange membrane (PEM) and alkaline. Alkaline is currently the most mature technology, which uses a saline solution to separate hydrogen from water molecules by applying electricity. PEM is slightly less mature and uses a solid membrane to separate the hydrogen from water molecules via an electric charge.

[4] Binder, M., Kraussler, M., Kuba, M., and Luisser, M. (2018).

For producing low-carbon hydrogen from natural gas with CCS, two technology options exist: steam methane reforming (SMR) and autothermal reforming (ATR). SMR combines natural gas and pressurised steam to produce syngas, which is a blend of carbon monoxide and hydrogen. Providers can easily capture about 60 per cent of the total carbon by separating the CO_2 from the hydrogen; the additional must be extracted from the exhaust gas, which is relatively expensive today, allowing for up to 90 per cent total capture rate.

ATR combines oxygen and natural gas to produce syngas. This process can easily capture up to 95 per cent of CO_2 emissions. ATR technology is typically used for larger plants compared with SMR technology.

Coal gasification produces hydrogen by reacting coal with oxygen and steam, which like the ATR plant, allows for a relatively easy capture of CO_2. However, the coal gasification plant emits about four times more CO_2 per kg of hydrogen produced than the ATR plant, increasing the amount of carbon that must be transported and stored.

Conditions for hydrogen production across regions and over time

The cost of hydrogen varies significantly across regions, as it depends heavily on the prices and availability of energy inputs. To produce low-carbon hydrogen from reforming plus CCS, companies require access to low-cost natural gas, such as in the US, where gas prices are below USD 3 per million British thermal units (MMBtu) and large-scale CO_2 storage (e.g. depleted gas fields, suitable rock formations). For renewable hydrogen from electrolysis, the crucial factor is access to low-cost renewables. For example, the levelised cost of energy (LCOE) for new solar power today can run as low as about USD 20 per MWh in regions such as North Africa.

When considering low-cost hydrogen's cost trajectory, the optimal cost of low-carbon hydrogen from reforming plus CCS could drop below USD 1.50 per kg in the short term in the most attractive geographic locations. In addition, the analysis shows that a carbon cost of about USD 50 per ton of CO_2e would allow low-carbon hydrogen to reach parity with grey hydrogen.

Low-carbon hydrogen production from reforming plus CCS is attractive in regions with natural gas, as it provides an option to leverage these resources. It is typically possible to store captured carbon in existing gas fields, and these countries often have the existing infrastructure and industry to handle gas. With enough scale, costs could drop to about USD 1.20 per kg in 2025 in regions like the US or the Middle East. For regions with higher average natural gas costs like Europe, low-carbon hydrogen from reforming plus CCS will cost around USD 2.10 per kg in 2020, declining to approximately USD 1.80 in 2030 due to the lower cost of carbon capture and carbon storage opportunities.

Regions such as Chile, Australia and Saudi Arabia have access to renewables from both wind and solar at low LCOE which enables high load factors for hydrogen production through electrolysis. They thus offer optimal potential for producing renewable hydrogen at minimum costs. Under these optimal conditions, hydrogen production could become available at costs of about USD 2.50 per kg by the early 2020s, declining to USD 1.90 per kg in 2025 and perhaps as low as USD 1.20 per kg in 2030. This is well below the average for grey hydrogen, and even close to parity with optimal grey hydrogen costs in 2030 if CO_2 costs are factored in.

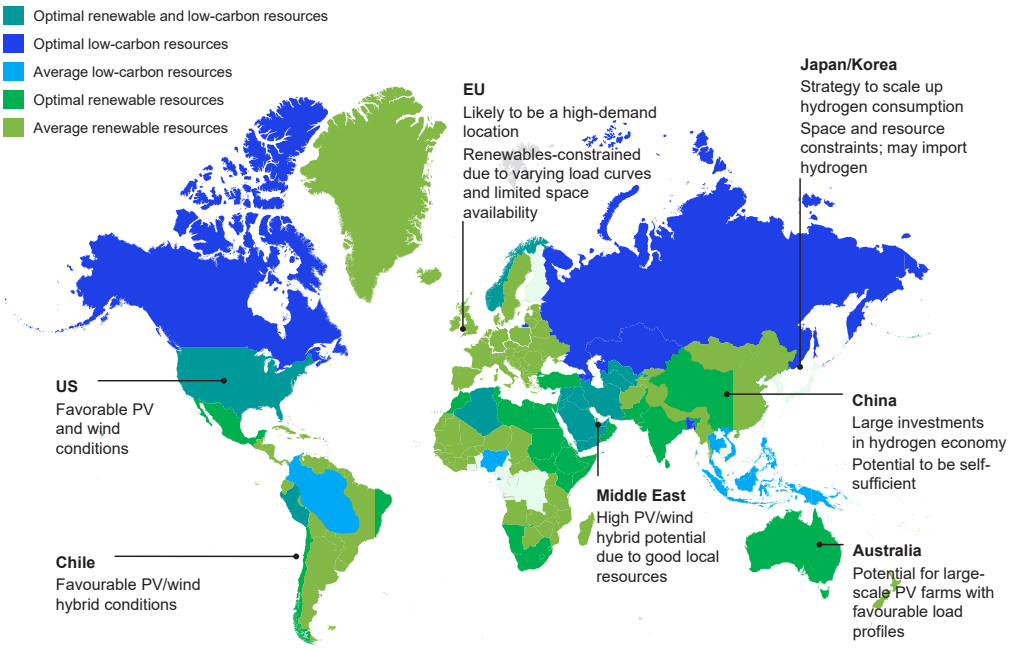
For regions where renewables cost are on average higher, e.g. Northern Europe, there are usually areas with favourable conditions for renewables. This makes it possible to produce hydrogen at lower-than-average costs and makes site selection for renewable hydrogen production of critical importance. The cost of renewable hydrogen produced from offshore wind in Europe starts at about USD 6 per kg in 2020. This rate is expected to decline by about 60 per cent by 2030 to approximately USD 2.50 per kg, driven by scale in electrolyser manufacturing, larger systems, and lower-cost renewables.

Other countries may have limited resources to produce low-carbon or renewable hydrogen at scale locally, such as Japan or Korea, and even parts of Europe. Some of these regions have ambitious decarbonisation policies that will require hydrogen; if local production cost is too high or unable to meet demand, they may become importers of hydrogen. Exhibit 12 shows where low-carbon hydrogen from reforming plus CCS and renewable hydrogen from electrolysis is projected to become cost competitive.

Grey hydrogen, the most competitive option today, should be fully phased out by 2050 to meet the 2-degree target. It is expected to become increasingly less competitive over time as the cost of CO_2 emissions increase, reaching cost levels higher than all low-carbon alternatives prior to 2040.

Exhibit 12 | Hydrogen production potential across regions

Best source of low-carbon hydrogen in different regions



SOURCE: IEA; McKinsey

Demand centres, e.g. EU, North-east Asia, are often constrained for resources, and may not be able to self-supply hydrogen.

Countries with complementary load profiles of wind and PV can produce renewable hydrogen at very low prices.

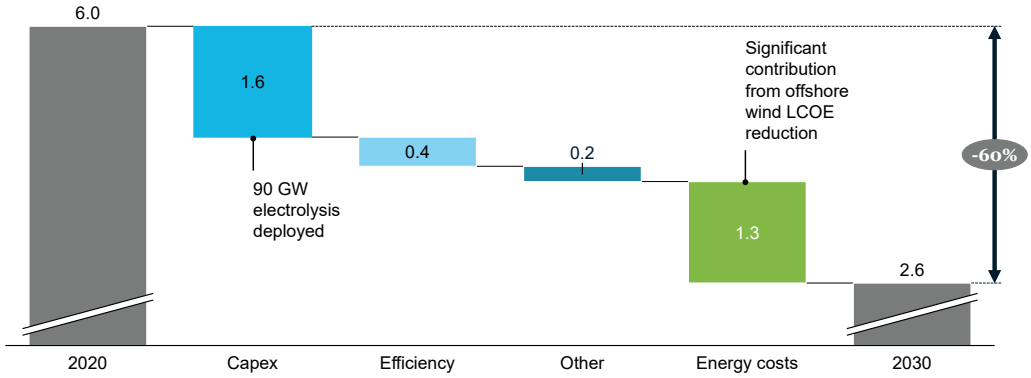
Regions like China and the US are both demand centres and have favourable RES.

Renewable hydrogen from electrolysis cost-reduction drivers

Since 2010, the cost of electrolysis has fallen by 60 per cent, from between USD 10 to 15 per kg hydrogen to as low as USD 4 to 6 today. The analysis shows that they will continue to fall: offshore wind-based electrolysis shows another 60 per cent cost reduction from now until 2030 (see Exhibit 13).

Exhibit 13 | Renewable hydrogen from electrolysis cost trajectory

Cost reduction lever for hydrogen for electrolysis[1] connected to dedicated offshore wind in Europe (average case)
USD/kg hydrogen



1. Assume 4,000 Nm3/h (~20 MW) PEM electrolysers connected to offshore wind, excludes compression and storage
2. Germany assumed

SOURCE: H21; McKinsey; Expert interview

Capex decreases ~60% for the full system driven by scale in production, learning rate, and technological improvements.

Increasing system size from ~2 MW to ~90MW.

Efficiency improves from ~65% to ~70% in 2030.

Other O&M costs go down following reduction in parts cost and learning to operate systems.

Additionally, storage may become cheaper (not included).

Energy costs[2] offshore wind LCOE decreases from 57 to 33 USD/MWh, and is assumed to be dedicated to hydrogen production.

Grid fees decrease from ~15 to 10 USD/MWh.

Load factor of 50%, i.e. ~4,400 full load hours equivalent.

Key drivers for continued cost reduction include the industrialisation of electrolyser manufacturing (-25 per cent), improvements in electrolyser efficiency and operations and maintenance (-10 per cent), and the use of low-cost renewable power (-20 per cent). The latter will be region specific and depend highly on access to renewable resources (sun and wind).

Regarding capex, a 60 to 80 per cent reduction from larger-scale manufacturing is expected by 2030. Important drivers of this drop include the shift from a largely manual production process to greater use of automation and 'roll-to-roll' streamlined production processes. Supporting factors include further technological improvements (like optimisation of catalyst loading), and increased system sizes, with associated scaling benefits. Moving from the 1 to 2 MW systems typically deployed today to, for instance, 80 to 100 MW systems can significantly decrease the cost contribution from auxiliary systems. In total, these improvements should reduce the capex from today's USD 2 per kg of hydrogen produced to USD 0.50 per kg by 2030. As mentioned in the previous chapter, this number might be conservative: the underlying learning rate is notably more conservative than in other 'new' technologies like solar photovoltaics (PV) and wind power. Thus, actual cost decline could happen even faster and accelerate the competitiveness of renewable hydrogen from electrolysis even more.

Higher efficiency results from incremental improvements in technology. The industry could increase lower heating value efficiency from around 64 to 68 per cent today for PEM/alkaline technology to about 70 per cent in 2030. Higher efficiency enables a smaller system using less electricity to produce the same amount of hydrogen, which would account for an approximate USD 0.40 per kg of hydrogen cost improvement. Additional O&M cost improvements should contribute another USD 0.20 per kg in cost cuts.

The lower cost of electricity from renewables will contribute the biggest share of reduction in operational cost. In the offshore wind example, a 40 per cent cost decline from approximately USD 70 to 40 per MWh could occur in 2030, accounting for lower costs of around USD 1.30 per kg.

Variations in renewables resources make renewable hydrogen from electrolysis production highly region specific. For example, solar paired with wind power in Chile should reduce hydrogen production cost to as low as USD 1.40 in 2030. Exhibit 14 shows the resulting production cost under different LCOE, utilisation, and electrolyser capex assumptions. The assessment also shows that even for a conservative assumption – an electrolyser capex of USD 500 per kW – access to renewables at USD 20 per MWh enables production of renewable hydrogen at about USD 2 per kg.

Exhibit 14 | Renewable hydrogen from electrolysis production cost scenarios[5], USD/kg hydrogen

Cost of renewable hydrogen with varying LCOE and load factors
USD/kg H_2

< USD 2/kg | USD 2-3/kg | USD 3-4/kg | > USD 4/kg | Viable medium-term (<2030)

LCOE	Capex electrolyser	USD 750/kW					USD 500/kW					USD 250/kW				
UDD 0/MWh		5.7	2.8	1.9	1.4	1.1	4.2	2.1	1.4	1.1	0.9	2.8	1.4	0.9	0.7	0.6
USD 10/MWh		6.1	3.3	2.4	1.9	1.6	4.7	2.6	1.9	1.5	1.3	3.2	1.9	1.4	1.2	1.0
USD 20/MWh		6.6	3.8	2.8	2.4	2.1	5.2	3.0	2.3	2.0	1.8	3.7	2.3	1.9	1.6	1.5
USD 30/MWh		7.1	4.2	3.3	2.8	2.5	5.6	3.5	2.8	2.5	2.2	4.2	2.8	2.3	2.1	2.0
USD 40/MWh		7.5	4.7	3.8	3.3	3.0	6.1	4.0	3.3	2.9	2.7	4.6	3.2	2.8	2.6	2.4
USD 50/MWh		8.0	5.2	4.2	3.7	3.5	6.5	4.4	3.7	3.4	3.2	5.1	3.7	3.2	3.0	2.9
USD 100/MWh		10.3	7.5	6.5	6.1	5.8	8.9	6.7	6.0	5.7	5.5	7.4	6.0	5.6	5.3	5.2
Load factor		10%	20%	30%	40%	50%	10%	20%	30%	40%	50%	10%	20%	30%	40%	50%

SOURCE: McKinsey

Low-carbon hydrogen production cost-reduction drivers

Low-carbon hydrogen from natural gas has the potential to enter the market with costs only about 10 to 20 per cent higher than those of conventional grey hydrogen, providing low-carbon hydrogen at scale. In addition to the cost of the natural gas feedstock itself, the other key cost components of low-carbon hydrogen from reforming plus CCS are CO_2 capture, transportation and storage.

The cost of the CO_2 capture process itself is estimated to be roughly USD 0.20 to 0.30 per kg for an SMR plant, and less than USD 0.10 per kg for an ATR plant where the process design leads to more concentrated CO_2 streams.

The second important factor is the cost and availability of CO_2 transport and storage. CO_2 storage is typically available in natural-gas-rich regions, as depleted oil and gas fields make good storage areas. However, this strategy requires significant upfront investments – often hundreds of millions[6] of dollars and several years – to finalise development. That is why projects expected to happen between 2025 and 2030, such as Northern Lights[7], require action and investment today. These projects generally seek to transport and store large amounts of CO_2, and thus they will depend on several industrial scale emitters to co-invest and share the cost burden. This is similar to conventional O&G investments, underlining the importance of developing high downstream demand for low-carbon hydrogen.

In addition to low-carbon hydrogen production from natural gas, it is also possible to produce hydrogen from coal gasification with CCS. The gasification of coal emits roughly four times more CO_2 per kg of hydrogen produced and consequently has higher required sequestration volumes. In addition, residual CO_2 emissions per kg of hydrogen are higher than for SMR/ATR. Thus, the tradeoff is between feedstock cost, which can be very low for regions that are rich in coal and have already established relevant infrastructure, such as China or Australia, and CO_2 sequestration and residual emissions cost. Overall, costs should amount to USD 2.10 per kg of hydrogen for a coal cost of about USD 60 per ton.

[5] The specified capex includes BoP. The assessment assumes additional 25 per cent for assembly/EPC and USD 65/kW for grid connection and building construction.
[6] Press reports on Northern Lights mention the requirement for over USD 1 billion in public funding.
[7] Equinor (2019).

Global hydrogen shipping

Since the costs of hydrogen production differ significantly between regions, long-distance transmission and international trade in hydrogen can be attractive. This is particularly true for countries like Japan or South Korea, which are expected to have large hydrogen demand but lack suitable locations to deploy power generation from wind and solar.

A global supply chain will likely consist of long-distance pipelines as well as shipping routes. Even existing natural gas pipelines can transport hydrogen, often with only modest upgrades. This could be an option, for example, to transport low-carbon hydrogen derived from natural gas from Russia or Norway into Central Europe; or renewable hydrogen from electrolysis from Northern Africa into Southern Europe.

For hydrogen shipping to become economically feasible, the industry needs to scale up its infrastructure, targeting to reach similar levels that liquid natural gas (LNG) has today in the mid to long term. Since ship-based imports will always directly compete with domestic production, domestic hydrogen cost levels and their potential to reduce will be decisive. In the case of Japan, the analysis shows that ship-based imports are economically competitive versus locally produced renewable hydrogen from electrolysis as long as local renewables' LCOE are above USD 60 per MWh or not available at a scale that could meet the full domestic power demand.

There are several technology options for shipping hydrogen globally. The three major archetypes are liquid hydrogen (LH2), ammonia (NH3), and a set of different technologies based on liquid organic hydrogen carriers (LOHCs).

LH2 shipping delivers hydrogen in pure form at the location of import. Today LH2 shipping costs are high (e.g. for the route from Saudi Arabia to Japan about USD 15 per kg in 2020), but with enough scale, they could fall to USD 1.7 per kg in 2030. Indeed, the technology is similar to that used for LNG, which supports quick scale-up given similar conditions as for LNG – namely large enough demand in demand centres to warrant investment into hydrogen production and transmission. This would require a scale-up of typical vessel capacity from 160 tons to about 10,000 tons, and liquefaction capacity from 10 to 50 tons per day to as much as 500 tons per day. In addition, if further transportation with trucks or storage in liquid form is required or direct use of hydrogen, e.g. for industry or fuel cell vehicles, LH2 shipping benefits this next step in the value chain as no further conversion to hydrogen is required.

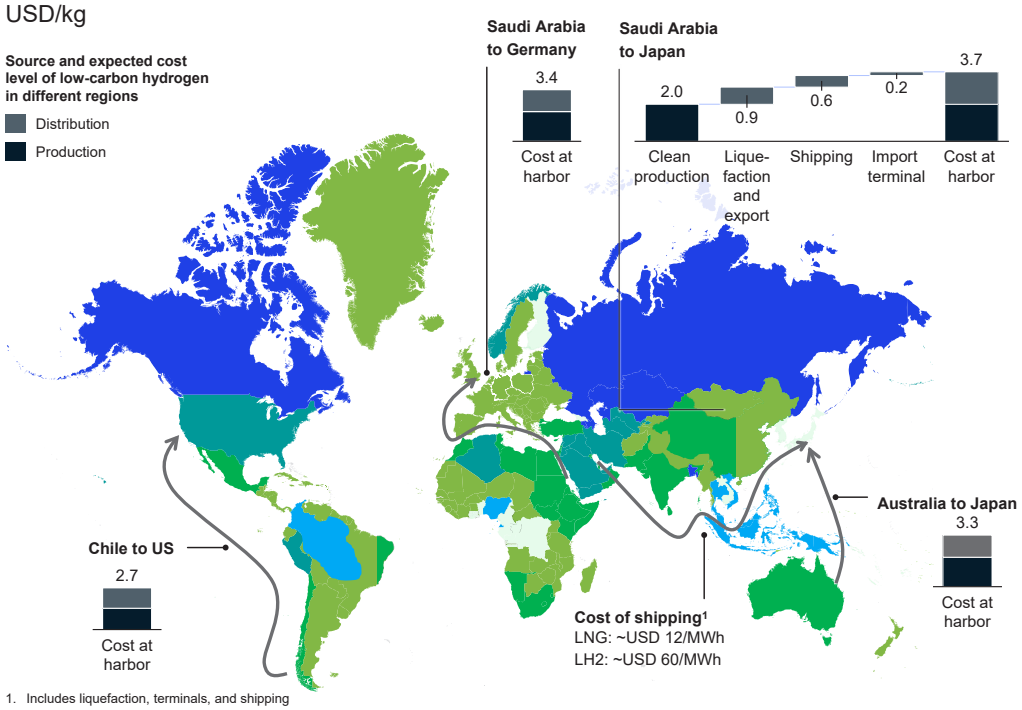
Exhibit 15 shows examples of potential shipping routes and end-to-end costs for LH2 shipping. It should be noted that these values are highly sensitive to scale-up and uncertainty around the opportunities for cost reductions remains.

Using ammonia as the hydrogen carrier has the benefit of leveraging existing infrastructure for global distribution. Additionally, the conversion from hydrogen to ammonia is a well-established technology. In cases where the end use is ammonia, shipping ammonia is the preferred option (but requires careful handling by certified operators due to its toxicity). However, if the end use requires pure hydrogen, an additional reconversion step is required, which is currently at an early stage of development. In addition, reconversion would require access to low-cost clean energy at the arrival port if the desire is to have a low-carbon or renewable hydrogen product: the absence of which is exactly why hydrogen was being shipped into the demand centre in the first place. Depending on the technology evolution and local conditions, this reconversion step could add another USD 1 to 2 per kg on top of conversion and shipping costs.

Exhibit 15 | Global shipping of hydrogen

Cost of shipping liquid hydrogen across regions, 2030

USD/kg



1. Includes liquefaction, terminals, and shipping

SOURCE: McKinsey Energy Insights

LOHC shipping based on a range of different chemical compounds, such as toluene or methyl-cyclohexane, has the benefit of leveraging existing shipping infrastructure and allows hydrogen to be transported and stored as a liquid. Like ammonia, a challenge lies in the dehydrogenation step, which requires scale-level development as well as significant energy input at the import destination. In contrast to ammonia, it also requires the return of the carrier to the port of origin. Further, there are several different LOHC technologies, hindering economies of scale unless global standardization is achieved. Given the low maturity of the technology, cost estimates for LOHC, as well as cycling rates, are still highly uncertain and require additional research and development. Therefore, a conclusive cost analysis was not undertaken in this study.

Which shipping technology will become the least cost option depends on the end uses, the required onshore transportation, scale up and technological development. If hydrogen is the end use, LH2 seems to be the closest to maturity across the value chain and the lowest-cost alternative by 2030, although significant scale-up will be a critical prerequisite for cost reductions.

Local hydrogen distribution

To reach sufficiently low hydrogen costs at the point of consumption, production (or delivery to a major centralised facility such as a port) is only part of the story. Often, hydrogen must also undergo local distribution to the end user.

Central, large-scale applications like ammonia production or refining will typically produce hydrogen either on-site or nearby (in the case of an industry complex with several hydrogen consumers) and then distribute it via pipelines. Since such infrastructure already exists today at scale, the cost contribution is minor, with limited cost-reduction potential.

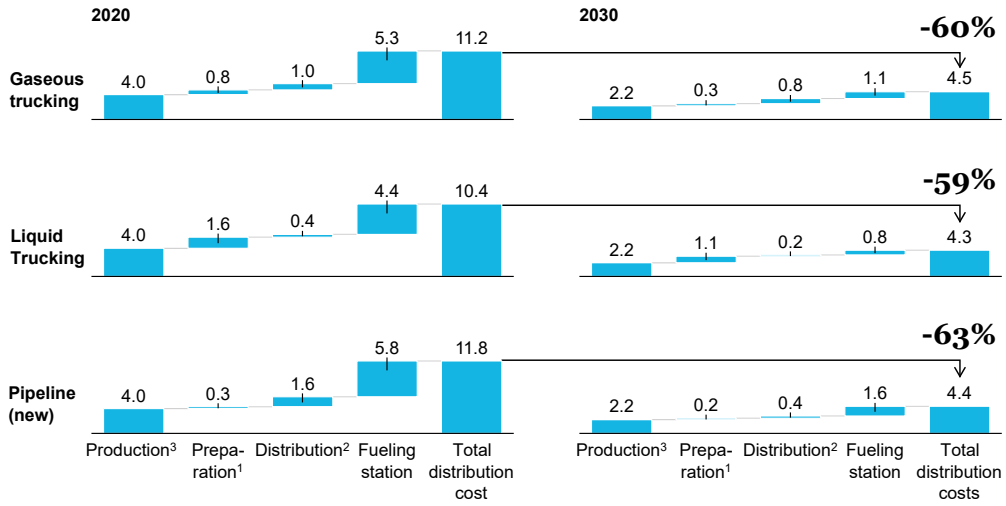
For decentralised users of hydrogen, the situation is different. Here, last-mile distribution is a major cost driver – often responsible for more than 50 per cent of the total hydrogen cost. That being said, The analysis suggests that hydrogen distribution can become highly competitive once the industry achieves scale and high levels of utilisation throughout the value chain.

Three main options exist for hydrogen distribution: 1) trucking of compressed hydrogen, 2) trucking of liquefied hydrogen, and 3) the use of pipelines. The decision of which distribution option to pursue will differ from case to case, based on the demand profile and the distance from supply. For shorter distances, compressed gaseous hydrogen (GH2) offers the lowest cost. Liquid trucking is most economical for distances above 300 to 400 km. If hydrogen is already available in liquid form at the production or delivery site, even shorter distances are economical.

Building a new hydrogen distribution pipeline network is a significant investment over multiple years but can become economical in cases that involve large volumes. However, companies could also use existing natural gas pipelines. Here, either hydrogen blending or – if the current network configuration allows for it – upgrades to pure hydrogen distribution, may make sense.

Analyses suggest that all the pathways for hydrogen distribution should decline significantly in cost over the next decade – by about 60 per cent including production, and by as much as approximately 70 per cent when only considering distribution and retail – bringing the cost of hydrogen at the pump to less than USD 5 per kg by 2030. Exhibit 16 shows the evolution of hydrogen cost including distribution for the three different options.

Exhibit 16 | Evolution of hydrogen cost for transportation



1. Compression for gaseous trucking, liquefaction for liquid trucking or storage for pipelines
2. Gaseous trucking, liquid trucking or pipelines
3. Assumes average blue and green production cost in Europe (Germany offshore wind)

SOURCE: McKinsey Hydrogen Supply Model

Scaling up distribution channels and refuelling stations is key for achieving cost reductions.

Pipelines are the lowest-cost alternative when there is a network to leverage and high hydrogen volumes.

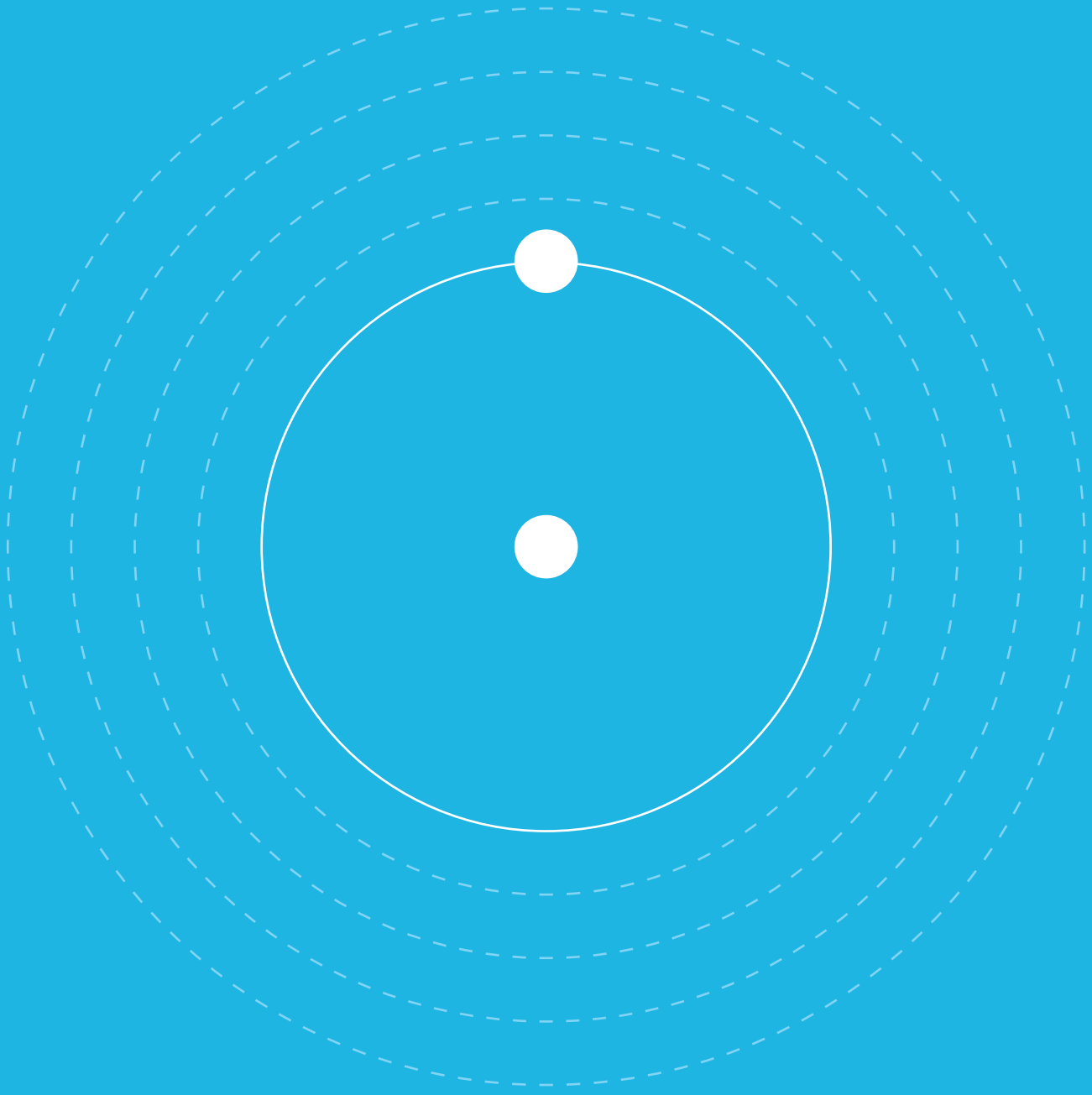
Energy consumption for the liquid and high-pressure routes is centralised; pipelines and low-pressure trucking require more higher-cost energy on-site.

Achieving this level of cost improvement depends on the scale-up of demand and the associated increase in utilisation of distribution infrastructure. For example, the main cost drivers in the trucking distribution pathway are as follows:

Increase in trucking capacity. Costs for gaseous and liquid hydrogen trucking should decrease by USD 0.10 to 0.20 per kg for typical distances of 300 to 500 km, due mainly to improved utilisation and lower equipment costs with rising scale.

Increasing scale and density of filling centres. Increasing utilisation and scaling up capacity of truck filling centers and liquefaction plants should reduce costs further by about USD 0.50 per kg for both liquid and gaseous trucking. A further cost decline is expected from the increasing density of filling centres: a reduction of trucking distance by 100 km on average will reduce trucking costs by another USD 0.10 per kg.

Scaling up demand and HRS size. Hydrogen refuelling stations are currently the highest cost element in the cost at the pump, accounting for about 70 per cent of total distribution and retail costs. Today's high cost primarily results from the low utilisation of even small stations due to the limited uptake of fuel cell vehicles. A cost decline of about 80 per cent is possible, from roughly USD 5 to 6 per kg in 2020 to about USD 1 to 1.50 per kg in 2030. The savings consist of higher utilisation (USD -2 per kg), increasing station size (USD -1 per kg) and industrialisation of equipment manufacturing (roughly USD -0.80 per kg).



Hydrogen could meet a **significant share of global energy needs** competitively

15%+

Share of global energy demand where hydrogen applications can compete with other low carbon alternatives by 2030

3 | Hydrogen applications

In this chapter, hydrogen's competitiveness is explored within each of the target end-use segments: transportation, heat and power for buildings, heat and power for industry, and industry feedstock.

Road transport

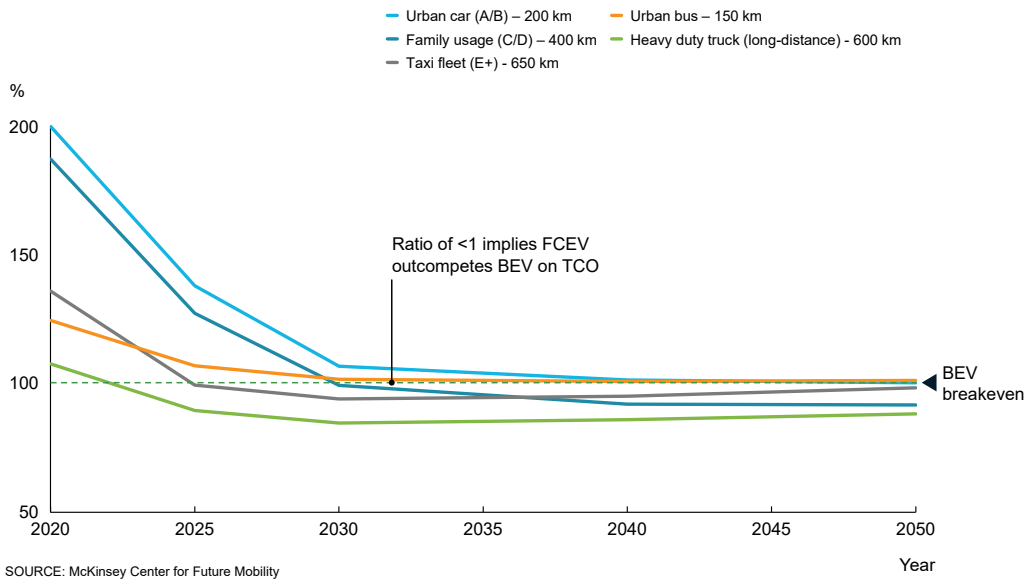
A range of road transport use cases with different types of vehicle and mobility patterns were considered, such as ranges, daily mileage, and payload (for trucks). Each use case was assigned a specific range in terms of tank, total mileage, and size of motor, and the TCO of three main technologies was assessed: fuel cell passenger vehicles, trucks, and buses. They were then compared with BEVs as the low-carbon alternative and internal combustion engines (ICE) as the conventional option.

The findings suggest hydrogen and fuel cell technologies are ideal for the decarbonisation of heavy-duty or long-range transport applications, as shown in Exhibit 17. These segments include use cases such as heavy-duty trucks, large passenger vehicles with long-ranges, and long-distance coaches. Heavy-duty trucks and coaches will likely achieve cost parity prior to 2025, because without breakthroughs in battery technology, the full battery alternative fails to meet commercial vehicle requirements due to the high cost and weight of batteries and relatively long recharging times. Meanwhile, large passenger vehicles with long ranges break even closer to 2030. For segments that require long-range capabilities, hydrogen is the most practical decarbonisation alternative.

For use cases with small vehicles and short ranges, like cars for urban use or short-range urban buses, the story differs. The battery required is relatively small, and as BEV technology becomes more developed it will remain the more competitive alternative, with hydrogen alternatives expected to remain more expensive than comparable BEVs. On the other hand, FCEVs will continue to offer higher range than BEVs. This increased flexibility may be decisive for vehicle purchase decisions that are not purely driven by TCO considerations. Ultimately, it depends on the consumers' willingness to pay for the increased flexibility of an FCEV compared to a BEV.

Exhibit 17 | TCO of road transport applications

TCO ratio between FCEV/BEV vehicles
No. average of 5 car segments ranging from small and low usage to large and high usage



SOURCE: McKinsey Center for Future Mobility

FCEVs are generally better than BEV in use cases that require long tank range due to:

— Lower cost of vehicle due to smaller battery

— Short refueling times made possible by Hydrogen

Longer charging time may imply fleets need to purchase a higher number of vehicles to provide same service.

For fleets developing infrastructure, FC offers additional economies of scale vs. BEV, which scale more linearly.

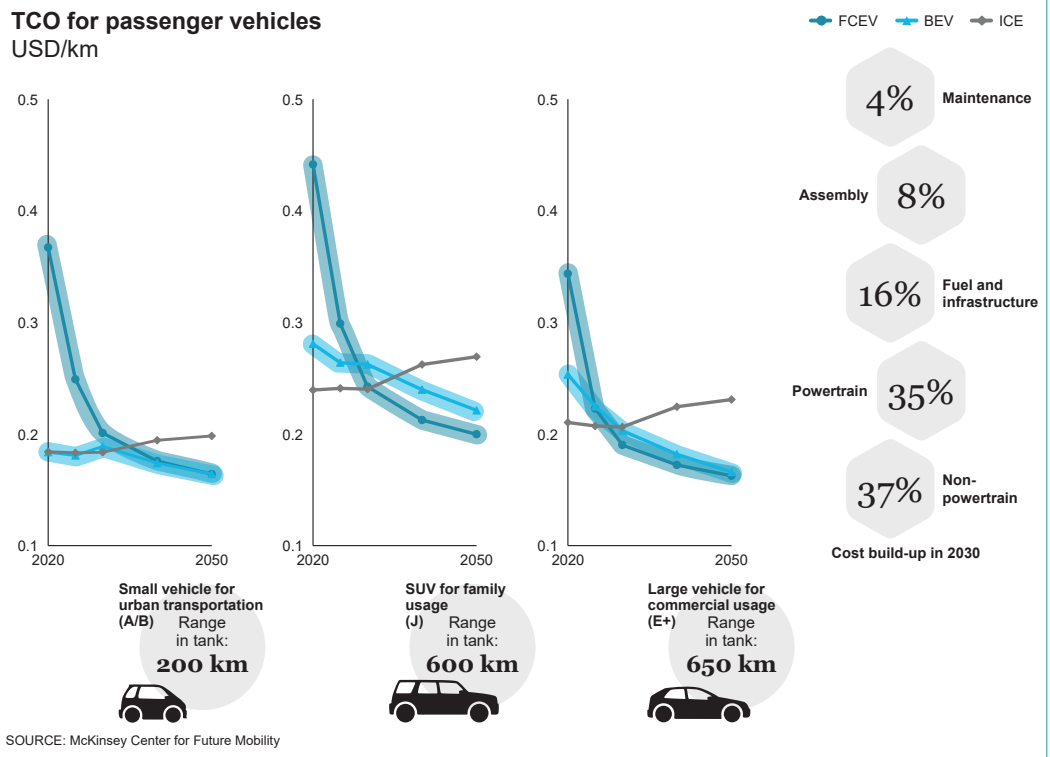
In the following sub-chapters, a more detailed analysis of each of the passenger vehicle, truck, and bus segments is provided. The TCO trajectory is explored in greater depth, including the conditions where hydrogen is most competitive, and the key cost drivers are identified across the value chain.

Fuel cell passenger vehicles

The cost analysis of passenger vehicles shows that the attractiveness of hydrogen applications varies across use cases, with fuel cell vehicles being more competitive in segments with heavier use and longer-range requirements (500 km or more between refuelling), such as large passenger cars, SUVs, or taxi fleets.

That being said, when the consumer considers the choice of vehicle and technology, factors beyond cost often emerge, including range, time to refuel, comfort, fuel efficiency, as well as the impact on the local and global environment. The final choice depends on all these factors, and ultimately comes down to the vehicle's intended use and mobility pattern.

Exhibit 18 | TCO trajectory of passenger vehicles



SOURCE: McKinsey Center for Future Mobility

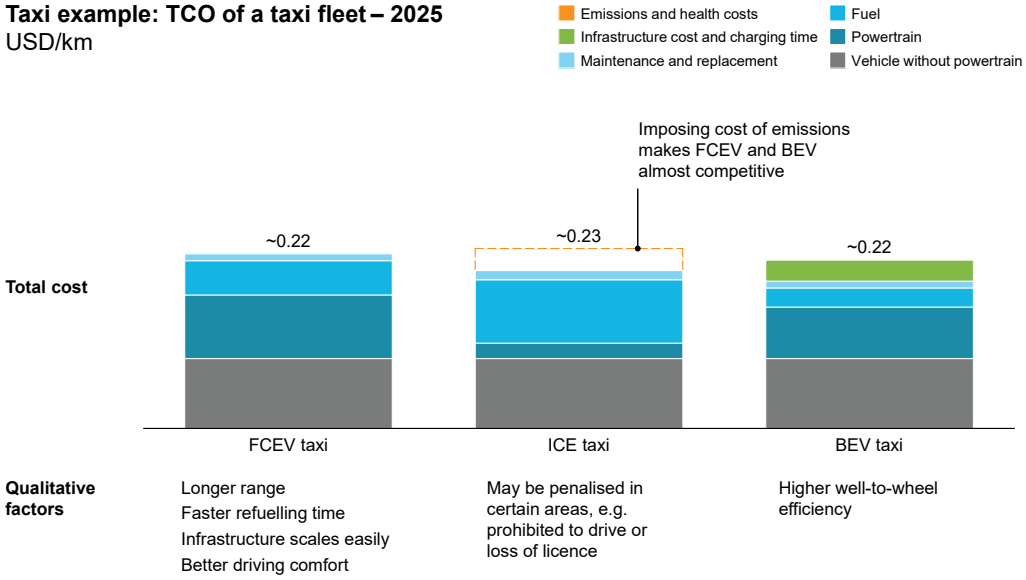
Cost competitiveness. Our analysis suggests that under the assumed scenario of production volume, hydrogen will outcompete BEVs by circa 2025 for taxi fleets where a range of 650 km is required, as shown in Exhibit 18. Sub-segments such as SUVs, large passenger cars and taxi fleets that have range requirements of 500 km or longer will be competitive earlier than smaller vehicles with shorter range requirements. Reaching these cost levels will require an estimated annual production of 600,000 vehicles worldwide, which should generate sufficient economies of scale and create adequate learning effects.

For the mid-size car with a 400 km range requirement, FCEVs will reach cost competitiveness around 2030. Considering a use case with a mid-size vehicle with a shorter range of 300 km, the FCEV reaches cost parity around 3 to 5 years later. This suggests that the BEV is more attractive for use cases with lower mileage and short range requirements in the foreseeable future.

Our findings for small, urban cars with 200 km ranges support this point. FCEV are not expected to reach cost parity in this segment, and only reach similar cost levels to BEV in 2040. Urban usage is a better case for BEVs due to the shorter-range requirement. They can use a smaller battery of 30 kWh, resulting in lower TCO impact. If fuel cells are to be competitive with BEVs, a price of hydrogen of well below USD 3 per kg at dispenser would be required in 2030.

Exhibit 19 | TCO of taxi fleet application

Taxi example: TCO of a taxi fleet – 2025
USD/km



SOURCE: McKinsey Center for Future Mobility

Considering the true cost of emissions to society, including CO_2 emissions and the health impact from local emissions, fuel cell vehicles are already comparing favourably in some cases.

For taxis, FCEVs place a lower total cost on society than combustion vehicles already by 2025, even considering the currently still high hydrogen refuelling costs and low scale of vehicle production.

Fuel cells are most attractive for fleet applications and will break even with BEVs around 2025. In fact, if one includes local regulations penalising polluting vehicles, FCEVs represent the lowest-cost alternative overall in 2025 even when compared with ICE vehicles. However, regulatory support is required, either to make decarbonised alternatives more attractive, or to penalise the conventional polluting alternative.

Fleets differ from personal vehicles in that they typically use centralised, dedicated infrastructure, which 'guarantees' high equipment utilisation and thus reduces the cost per refuelling. For BEVs, economies of scale in fleet operations face limits, since one charger can only serve a finite number of vehicles in a given timeframe. Consequently, recharging times impose a potential limit on BEV fleets, meaning they would need a higher number of vehicles compared with FCEVs.

Cost development. Today, components of the fuel cell vehicle, such as the fuel cell, hydrogen tank and battery, account for about half of the vehicle's TCO, while hydrogen fuel accounts for roughly 25 per cent of costs. By 2030, these components are expected to make up approximately 30 per cent of the TCO and hydrogen fuel around 15 per cent, and the overall TCO to drop by up to 50 per cent. The key cost reduction factors include the cost reduction in the fuel cell powertrain and of hydrogen supplied at the pump, accounting for more than 90 per cent of the cost reduction until 2030. In the following, the possibility for costs to decline is discussed for each of these two main cost components.

Manufacturing costs largely drive fuel cell costs, and these are in turn largely determined by production volume. Today, fuel cell manufacturing is manual and small in scale, with less contribution from material cost. By taking advantage of production volume increases, companies can achieve significant cost reductions for several reasons. Firstly, procurement costs will decline as suppliers invest in equipment to deliver larger quantities of fuel cell membrane electrode assemblies (MEAs) and ionomers. Secondly, production line automation will lower production line labor costs, as will the development of advanced manufacturing technology. Thirdly, higher volumes will enable companies (at least initially) to utilise their equipment better; for example, at lower volumes, an automated stacking system routinely runs at less than 10 per cent of full capacity. Fourthly, manufacturers will streamline production at higher volumes, and source cheaper and lighter materials for the fuel cell balance of plant (BoP). With an annual production volume of 200,000 vehicles, a decrease in the cost of the fuel cell system would be estimated at around 45 per cent, rising to as much as 70 per cent with an annual production of 600,000 vehicles.

Another key cost component is the hydrogen tanks. They contribute up to about 15 per cent of total vehicle capex today, declining to only roughly 7 per cent in 2030. A cost decrease of approximately 55 per cent is projected at global production of 600,000 vehicles per year. Three factors will drive the reduction in tank cost. Firstly, the bill of material will go down per tank as production scales up to industrial levels from a few hundred or thousand of tanks at sub-commercial scale, which will allow costs to be amortised across a larger number of units. Cost of procuring parts will also go down as suppliers build new production lines. The carbon fibre is particularly important, as it is the largest share of the materials cost. Secondly, the high costs for certification of components can be amortised across many more units. The cost of production certification will also decline as the process becomes more automated and repeatable, the latter meaning that smaller samples will be required. Thirdly, automated production lines and higher utilisation of existing equipment will directly reduce production costs.

One additional consideration for reducing tank costs is the potential for reducing safety standards. Today the safety factor for 700 bar tanks is 2.25, meaning that the tank must be able to withstand up to 1,575 bar pressure. Reducing this to 2, i.e. ability to withstand 1,400 bar, proportionally reduces the amount of carbon fibre required. This will be possible once the production process is industrialised, automated, and repeatable, and based on a proven track record of safety.

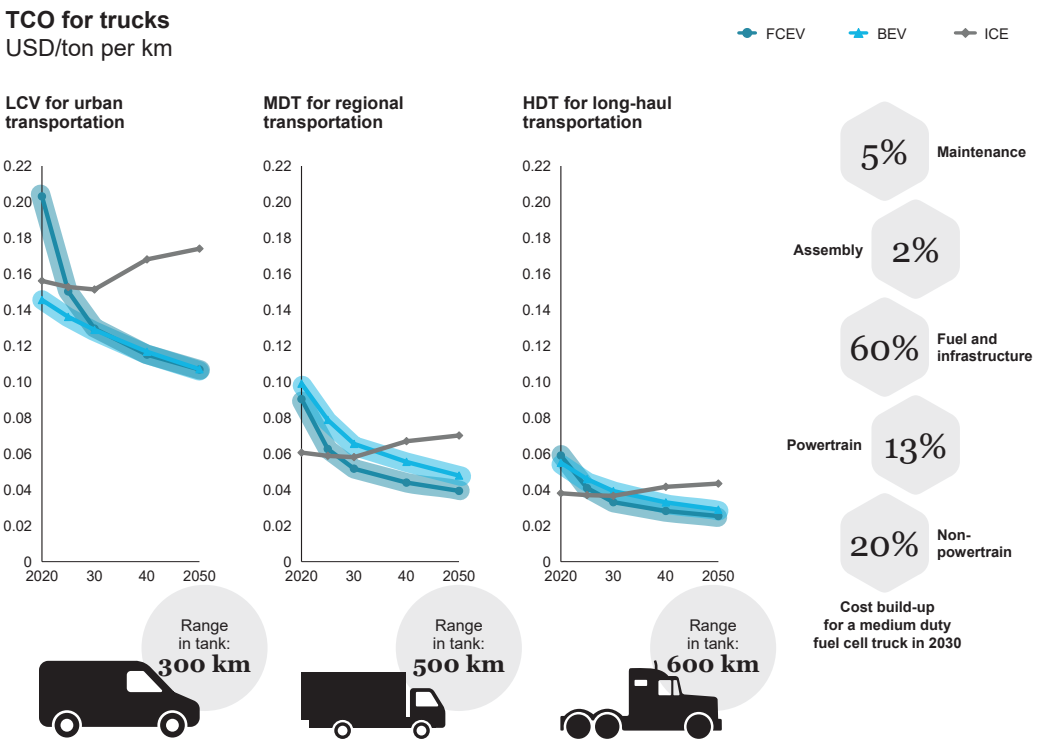
Fuel cost is the second-largest cost contributor for hydrogen passenger vehicles. Today, costs are high at about USD 10 to 12 per kg at the pump. Given the scale-up of vehicle deployment, supply and distribution channels must achieve greater scale to meet demand. For this, the entire value chain will scale up, resulting in a cost reduction at the pump by about 60 per cent, to beween USD 4.50 and 5 per kg. As explored in the prior chapter, three main factors will drive this cost drop: the production of lower-cost hydrogen, a larger and better utilised distribution system, and bigger and better utilised hydrogen refuelling stations. The last factor accounts for the largest share of value chain cost, contributing about USD 5 to 6 per kg of total cost in 2020, declining to roughly USD 1 to 1.50 per kg in 2030.

Fuel cell trucks

The analysis of fuel cell trucks suggests that this technology is the lowest-cost way to decarbonise both the medium- and heavy-duty segments. The BEV alternative is less attractive for heavy, long-range segments due to the large size (payload penalty), weight penalty, and cost of the batteries required, as well as the long recharging times. Three use cases were considered: 7.5-ton light commercial vehicles with a 300-km range requirement (LCVs), 13-ton medium-duty trucks with a 500-km range requirement (MDTs), and 22.5-ton heavy-duty trucks with a 600 km range requirement (HDTs).

In addition to the upfront cost for the vehicle and the lifetime fuel costs, the end users – most often fleet operators in these use cases – also consider factors such as refuelling time, available payload, operation under different climate conditions, and local regulations. All these effects influence the total cost of operating the fleet, which is ultimately what matters to such operators.

Exhibit 20 | TCO trajectory of trucks



SOURCE: McKinsey Center for Future Mobility; CARB Advanced clean truck; ICCT

Cost competitiveness. As discussed in Chapter 1, fuel costs are a significant component of the cost for trucks, particularly for HDTs and MDTs, accounting for about 60 per cent of TCO. For LCVs, fuel accounts for roughly 45 per cent of TCO. The fuel cell powertrain accounts for about 20 per cent of the cost for all segments.

Fuel cell MDTs and HDTs could become lower-cost alternatives to comparable BEVs as soon as 2025. The need for long-range capabilities mainly drives this assertion, which for the MDT and HDT segments likely translates to very large 600 to 960 kWh batteries. Batteries of this size are expensive and heavy and reduce the payload of the vehicle – particularly for HDTs with the largest batteries. Batteries this big also require long charging times, even with high-capacity fast-chargers (200 to 250 kW today, possibly more in the future). These fast chargers would potentially lower battery size requirements but would result in higher grid infrastructure costs.

Conversely, LCVs have a shorter range requirement and size, and correspondingly, smaller batteries of around 130 kWh. The BEV alternative therefore remains competitive in this case.

What may be more surprising is that fuel cell trucks may break even with conventional technology before 2030 in some regions, given a hydrogen cost at the pump of between USD 4 to 5 per kg (the exact break-even point depends primarily on the cost of diesel). FCEVs are more fuel efficient than ICE-powered vehicles and have the added benefit of recovering energy when braking or driving downhill, to some extent compensating for the higher cost of fuel.

Cost development. Cost reductions are possible because of the savings potential of two main cost components: the price of hydrogen at the pump, and the cost of equipment including fuel cells and on-board hydrogen tanks. Given annual sales volumes of 150,000 a year projected for 2030, the TCO trajectories shown in Exhibit 20 are feasible.

The majority of the cost drop from 2020 to 2030 will result mainly from cuts in hydrogen fuel cost, which will account for about 80 per cent of the TCO reduction for MDT and HDT, and roughly 60 per cent for the LCV. This follows a cost reduction of about 50 per cent for hydrogen delivered – from approximately USD 8 to 10 per kg in 2020 to about USD 4 to 5 in 2030, assuming the large scale-up envisioned.

Approximately 30 per cent of this reduction will result from the lower cost of hydrogen production, and the remainder from the lower cost of distribution. Distribution costs will decline due to lower-cost retail hydrogen, driven by increasing station size and utilisation, which should generate a 70 per cent lower cost allocated to hydrogen refuelling stations. There are additional improvements expected for compression and trucking of hydrogen.

The cost of fuel delivered to FCEV trucks is lower than for passenger vehicles because these trucks are typically served by larger stations with higher utilisation. This is due to two factors: firstly, trucks require larger volumes for each vehicle, e.g. an HDT has a tank that is about ten times larger than an SUV's. Secondly, trucks operate in fleets, which in many cases enables high utilisation of dedicated refuelling infrastructure.

The second major cost-reduction driver for hydrogen fuel cell trucks is equipment costs. The high cost of fuel cells and hydrogen tanks will primarily drive the cost of the powertrain in 2020, at which point the fuel cell truck will be about three times the cost of a comparable diesel vehicle. By 2030, scale manufacturing of fuel cells and hydrogen tanks could compress this gap by about 1.2 times.

A cost reduction of roughly 70 to 80 per cent for the fuel cells would be possible given an annual production volume of 150,000 vehicles; similar reductions could also be reached for the PEM stack and the fuel cell balance of plant. Manufacturers could capture significant fuel cell cost reductions of approximately 60 to 65 per cent with even relatively small annual production volumes of 10,000 trucks per year. The impact is higher for trucks than for passenger vehicles at the same volumes because of the larger fuel cell systems needed (two to four times the size of passenger vehicle systems) and a corresponding higher number of PEM stacks.

The hydrogen tank is a major part of the cost and accounts for 25 per cent of the total HDT investment cost in 2020 – less for MDTs and LCVs – and declines to about to 15 per cent of the cost in 2030. This results from achieving manufacturing scale in hydrogen tanks, which should enable a reduction of 60 per cent with an annual production of 150,000 trucks per year. With an annual production of only 10,000 vehicles, cost reductions of roughly 50 per cent should occur.

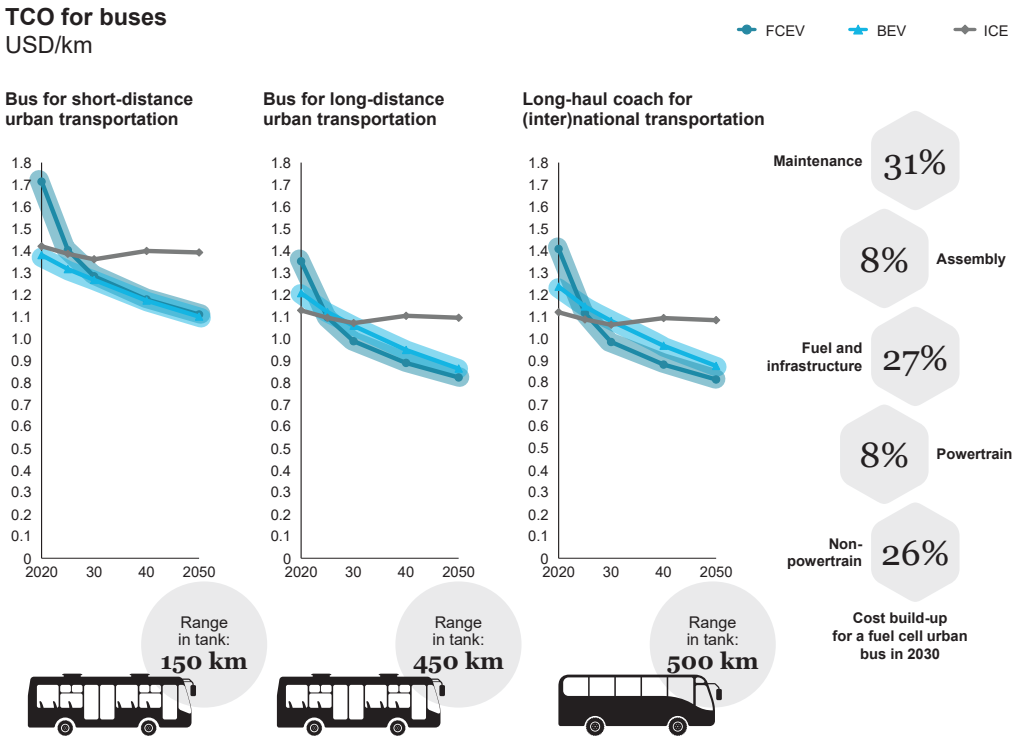
It should be noted that multiple options exist for truck hydrogen tank systems, which could feature on-board tanks with 350 or 700 bar pressure. The 700 bar specification allows for smaller tanks due to 70 per cent higher hydrogen density. Cryogenic tanks, which carry liquid hydrogen at atmospheric pressure, are also a possibility, with 90 per cent higher density than the 700 bar tanks. Although these tanks are not yet commercially available, they have the benefit of taking up less space and weight, allowing for more volume and weight for carrying goods, ultimately with further potential improvements for TCO.

Fuel cell buses

The cost analysis of fuel cell buses (FCEBs) shows that hydrogen is the most cost-efficient way to decarbonise long-range bus segments in the medium term, but it will not cost less than a comparable battery bus (BEB) for short-range urban use. The analysis considers three specific use cases for fuel cell buses: short-distance urban buses with a 150-km range per refuelling, long-distance urban transportation with a 450-km range, and coaches for long-distance travel with a range of 500 km. As for other road transport applications, this analysis compares fuel cell buses with BEBs and conventional diesel buses.

The key decision criteria for a bus operator is the cost of acquiring buses and operating them, in addition to a range of other important parameters like refuelling time, comfort and space requirements, operations in hot or cold climates where relevant, flexibility across line requirements, and the cost of infrastructure required to refuel. All these factors influence the choice of technology, but cost is ultimately what matters most to bus fleet operators. However, given that many urban bus fleets are subsidised today, this may be a segment where policy decisions could drive early uptake.

Exhibit 21 | TCO trajectory of buses



SOURCE: McKinsey Center for Future Mobility

Cost competitiveness. The analysis reveals that fuel cell buses outcompete full battery buses when the range required exceeds 400 km, due to the BEB's large, heavy battery and long charging times. For coaches, the full battery alternative is challenging today due to its size, weight, and recharging time. For buses with shorter ranges, e.g. urban buses, BEBs remain more competitive, as the battery required is much smaller and therefore less expensive.

Both fuel cell long-distance urban buses and coaches could outcompete BEBs in 2025, and even ICE buses before 2030, as shown in Exhibit 23. By 2030, urban short-range fuel cell and electric buses reach cost parity and remain so until 2050. This implies that the lowest-cost application will be highly sensitive to local conditions such as costs of electricity or hydrogen fuel, available infrastructure for refuelling, range required, and mileage. For example, longer mileage will benefit the BEB due to its higher efficiency and lower fuel consumption. The FCEB competitiveness, on the other hand, would benefit from higher grid electricity cost or requirements for longer range and flexibility. Ultimately, the optimal technology choice will depend on the fleet operator preferences for flexibility, operational constraints and infrastructure costs.

FCEBs have the benefit of providing higher flexibility and longer ranges for less additional investment than BEBs, and no impact on refuelling time. BEBs can take advantage of 'opportunity charging' (charging during stops to prolong driving range), and thus can ultimately have a smaller, cheaper battery. However, this strategy is expensive from a network perspective, as fleets must install more fast chargers and associated infrastructure.

Cost development. For FCEBs, roughly 10 per cent of TCO is contributed by the fuel cell powertrain and 25 per cent by fuel, as shown in Exhibit 21. For the coach, the cost is divided differently due to the larger motor and higher total fuel usage: the powertrain accounts for about 12 per cent and fuel approximately 40 per cent.

Achieving cost parity will require a scale-up in both the manufacturing of FCEB components and the hydrogen value chain. Companies will likely reach parity for coaches and long-range urban buses when annual production volumes reach 2,500 buses, while a production volume of 20,000 buses per year is required for the short-range urban bus to be competitive with the BEB.

Reducing fuel costs represents the largest cost-cutting opportunity for FCEBs, accounting for about 70 per cent of the TCO reduction for long-range urban buses and coaches, and somewhat less for short-range urban buses. By achieving annual production volumes of about 20,000 buses per year, the industry can already begin to achieve enough scale in the supply and distribution value chains to make a difference. This can potentially lead to fuel cost reductions of about 50 per cent, reaching costs of approximately USD 4 to 5 per kg, as market demand would drive down costs. Hydrogen costs for buses, as for trucks, are lower than those for passenger vehicles due to the high utilisation of dedicated refuelling stations for fleets and larger-scale stations. For instance, a coach carries more than ten times more hydrogen than a mid-size vehicle with a range of 400 km.

The lower cost of equipment is the other major cost-reduction driver. Reaching 2,500 vehicles per year will cause fuel cell costs to decline by roughly 65 per cent to about USD 100 to 110 per kW. A further production increase to 20,000 vehicles annually will yield additional cost improvements of around 30 per cent. This will lead to a total fuel cell cost reduction of about 80 per cent in total compared to 2020 levels.

Cost reductions for hydrogen tanks are slightly lower, with a roughly 50 per cent reduction achieved with a production scale of 2,500 units per year, and approximately 60 to 65 per cent with 20,000 units per year. Because tanks are similar across multiple types of vehicles, the knock-on effects caused by greater scale will probably emerge in passenger vehicles, trucks, and buses.

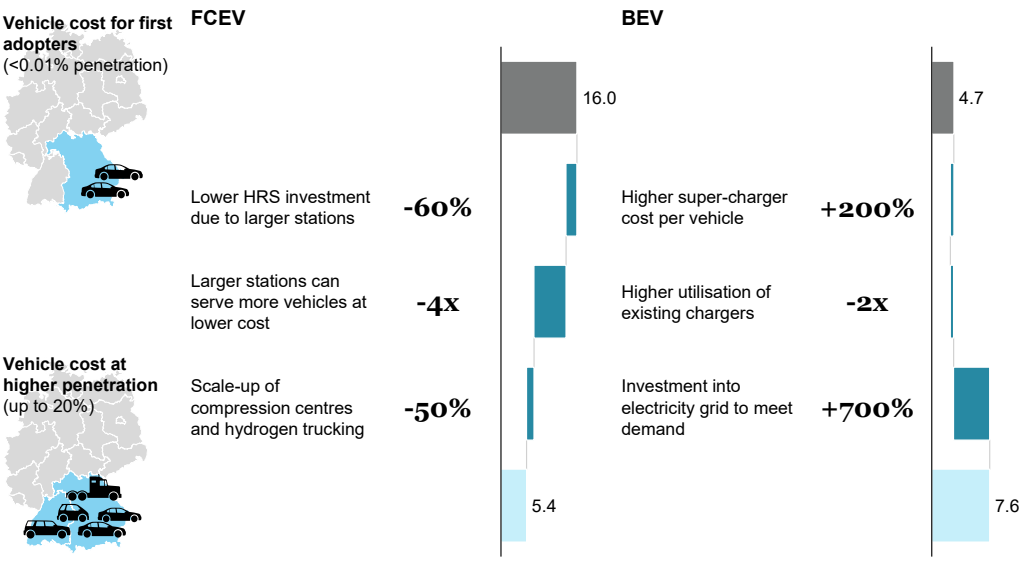
Buses can potentially use tanks with different pressures or even liquid on-board storage. Higher-pressure tanks or liquid tanks require less space but are more expensive, which may be acceptable if long ranges and enough space for passengers are required. Ultimately, it comes down to a question of consumer need and what type of value chain yields the lowest total costs, since a higher-pressure tank value chain is about 5 to 10 per cent more expensive due to greater compression specifications and the higher-pressure storage required.

Road transport infrastructure cost

When assessing and comparing TCO across transport application alternatives, the most critical competitiveness driver is the cost of infrastructure and how it develops with increasing scale. While a lot of uncertainties remain regarding the future trajectories of infrastructure scale-up, the infrastructure cost of FCEVs initially comes in significantly higher than for BEVs, but swiftly becomes cheaper with increasing market share in a given area. The tipping point appears to occur when FCEV market share reaches approximately 1 per cent, with pockets of higher presence of about 20 per cent, as shown in Exhibit 22.

Exhibit 22 | FCEV and BEV infrastructure and operations cost over lifetime

Cost of refuelling/recharging infrastructure investment and operations over lifetime (Germany use case)
USD/vehicle, thousands



SOURCE: McKinsey Center for Future Mobility

Accordingly, the cost of hydrogen refuelling infrastructure per vehicle is initially three to four times higher than for BEVs but should ultimately drop to below of the cost of BEV recharging infrastructure. It will reach cost parity due to the significant economies of scale available from increasing the size of distribution channels and the introduction of larger retail stations. For example, the cost of investment per kg of pumping capacity from a hydrogen refuelling station (HRS) will decline roughly 70 per cent over time, from about USD 6,000 for a small station in 2020 to an estimated USD 2,000 for a large station in 2030.

From a system perspective, BEV infrastructure costs typically increase with the increased introduction of fast chargers in the system and grid upgrades that may be required to cover the increased load. These costs were assumed to be allocated across all BEVs depending on their lifetime distance driven – a plausible approach, given that the costs of new infrastructure will probably have to be assumed in the electricity charging price. That being said, in a world where slow-charging dominates and there is effective demand management, costs may actually be lower than estimated. In addition, BEVs can initially enter the market with lower infrastructure costs, particularly if customers primarily use low-cost home-charging systems.

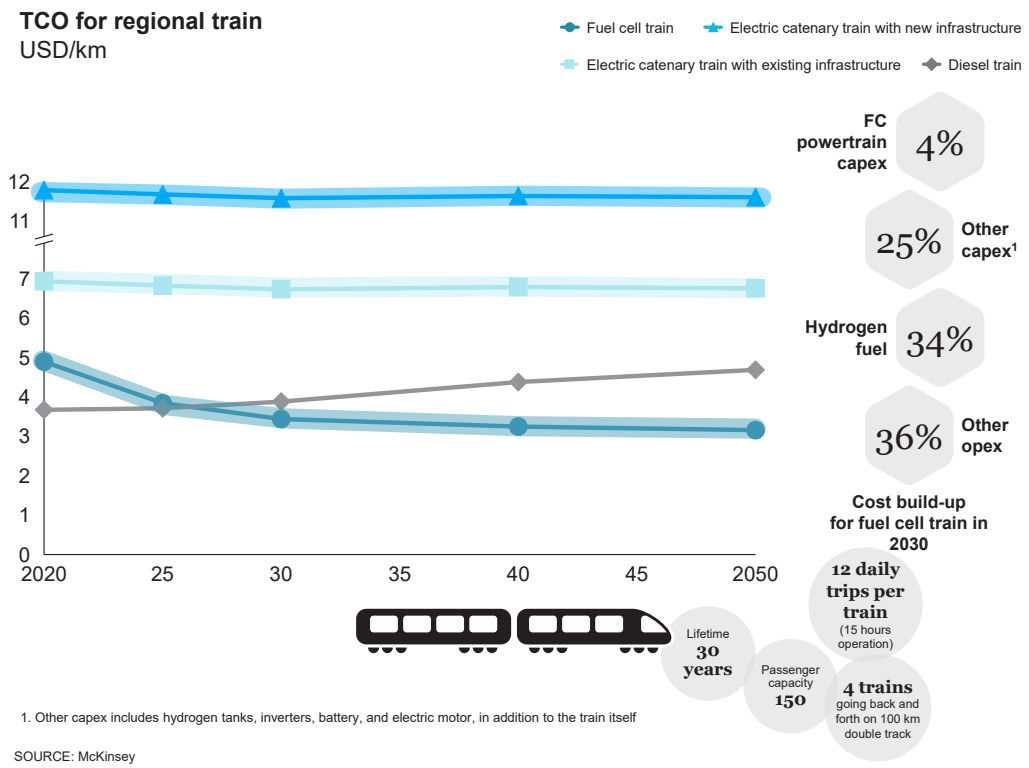
Fuel cell trains

The fuel cell train is a strong alternative for regional trains, outcompeting electric catenary trains in 2020 in areas where there is no existing catenary line in specific use cases. However, to beat diesel trains, it requires a cost of carbon of up to 120 per ton of CO_2e, depending on the region and the comparative cost of hydrogen and diesel fuel.

Our use case for this analysis consisted of four trains travelling a distance of 100 km and conducting a total of 24 return trips per day. We compared the fuel cell train with an electric catenary train both with and without existing overhead catenary lines as the low-carbon alternative, and we used combustion engine trains using diesel as the conventional option. We did not consider battery-driven trains with opportunity charging, which may of course be a possibility, but will require technological development and significant investment in charging infrastructure at multiple locations. The choice of technology depends largely on cost. However, this is influenced by several factors, including the existing rail network and infrastructure, topography, distance, usage frequency, environmental targets, and operating mode, which considers the duration of trips and the amount of downtime.

The hydrogen fuel cell train is best suited for longer, relatively low-frequency routes, with short downtimes and limited time for battery charging, and routes not already electrified. Ongoing projects already exist, and stakeholders have announced several more. For instance, there are already trains operating in Germany, and the East Japan Railway Company has announced it will develop hydrogen fuel cell trains with expected delivery in 2024.

Exhibit 23 | TCO trajectory of regional trains



1. Other capex includes hydrogen tanks, inverters, battery, and electric motor, in addition to the train itself

SOURCE: McKinsey

Cost competitiveness. As shown in Exhibit 23, our analysis suggests that the hydrogen train is already more competitive than electric catenary for a use case with relatively long distance and low frequency. However, as noted above, this conclusion will largely depend on key factors such as travel distance and frequency. In our specific use case, we find that by increasing frequency to 48 round trips per day and reducing the travel distance to 50 km, electric catenary solutions would cost less than the hydrogen alternative.

Cost development. Although the regional fuel cell train is already an attractive alternative today, room for cost cuts also exist to further improve competitiveness for other types of use cases. Cost reductions will likely come from the fuel cell system, on-board hydrogen tanks, and the value chain for hydrogen fuel, with the largest reductions available from the cost of fuel. The cost trajectory of components should be similar to that of heavy-duty vehicles, with some premium segment effects due to the smaller volume of trains compared to trucks.

Today the fuel cell system accounts only for about 3 to 5 per cent of the train TCO, equivalent to 10 to 15 per cent of purchasing cost. Similarly, the hydrogen tank accounts for roughly 3 to 5 per cent of the total cost of ownership. With projected cost improvements, the combined cost share of the fuel cell system and tanks should fall to approximately 2 to 4 per cent: a decline of about 60 per cent.

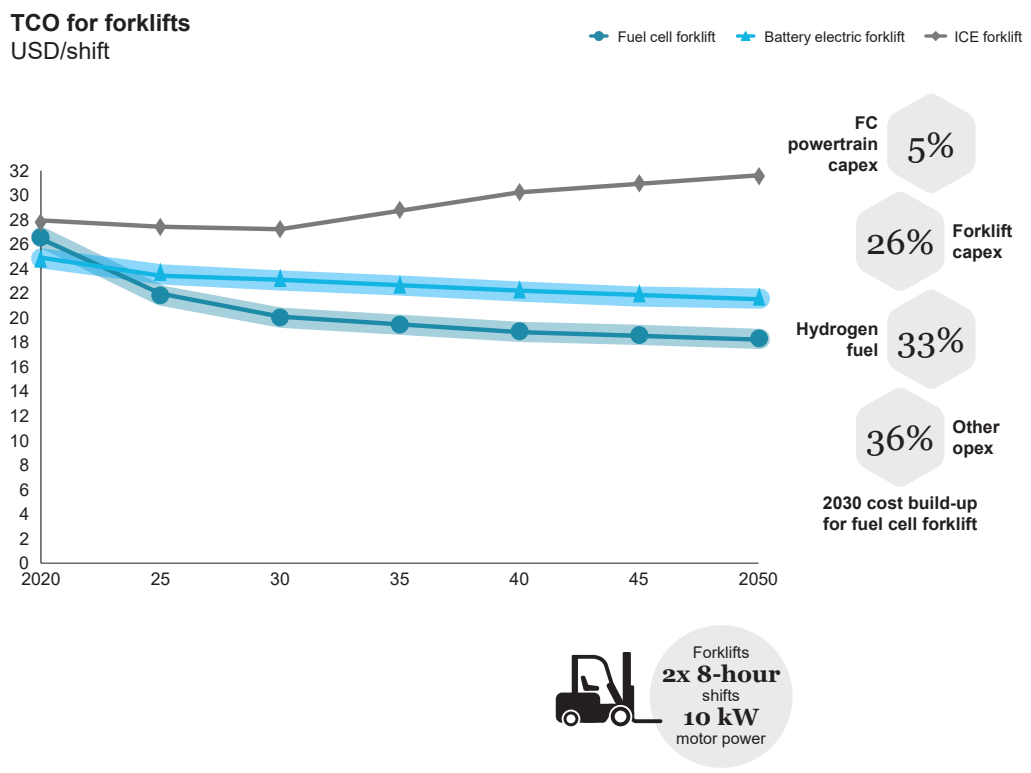
Like trucks and buses, trains will have dedicated infrastructure conducive to high utilisation rates, and they take advantage of a larger supply chain in the short term. Today the fuel probably accounts for about 40 to 50 per cent of a train's total cost of ownership and could decline to around 20 to 30 per cent in 2030. For this to happen, hydrogen cost at the pump must drop below about USD 4.50 per kg in 2030, or about half of today's price. We believe this is possible, given the scale-up of both low-carbon and/or renewable hydrogen production and distribution.

Fuel cell forklifts

Fuel cell forklifts would already be competitive given sufficiently low hydrogen costs of around USD 6 to 7 per kg. The analysis assumes that a forklift operating in a warehouse on two eight-hour shifts per day with one refuelling able to cover both shifts.

Fuel cell forklifts were compared with full battery electric units as the low-carbon alternative, and diesel as the conventional alternative. Even today, both the fuel cell and battery technologies outcompete the diesel in the right conditions.

Exhibit 24 | TCO trajectory of forklifts



Cost competitiveness. As shown in Exhibit 24 the fuel cell forklift breaks even around 2023 compared to the full battery version, even given a hydrogen production cost of approximately USD 3.50 per kg, not including distribution, confirming that fuel cell forklifts are a highly competitive near-term hydrogen application. Compared with diesel, the fuel cell is already the lower-cost option, even when considering the relatively high cost of hydrogen fuel and a very limited penalty for carbon emissions (about USD 30 per ton of CO_2e). Two factors contribute to this situation: higher fuel costs due to lower powertrain efficiency, and the limited cost benefit for the ICE due to the small motive power (10 kW) requirement. This implies that for vehicles with smaller motive power requirements, conventional alternatives offer fewer benefits.

Cost development. The total cost of fuel cell forklift ownership is projected to decline by about 20 per cent through 2030, with a total decline of around 30 per cent by 2050. Like other transport applications, the key cost-reduction drivers include expected declines in the cost of the fuel cell powertrain, particularly the cost of the tank system given the small fuel cell (10 kW), and the cost of hydrogen fuel.

Initially, the fuel cell system's share of capex is roughly 4 per cent, declining to about 2 per cent following the scale-up of fuel cell manufacturing for transport applications. The hydrogen tank represents a notably larger share of the cost, as one refuelling must cover two shifts. In 2020, the share of capex is expected to be about 15 per cent, declining to 10 per cent in 2030 following a reduction of about 30 per cent for the tank itself, and improved powertrain efficiency due to incremental technological improvements.

The hydrogen cost at the pump in 2020 is expected to be relatively low, as users typically operate forklifts constantly. This results in high utilisation for the refuelling infrastructure even at this early stage, although this clearly depends on the size of the fleet, the refuelling station required and forklift fleet operational scheduling.

The cost of hydrogen at the pump is expected to decline by about 45 per cent by 2030 for forklifts, driven by both lower production costs and the scale-up of the distribution value chain – the latter accounting for around 70 per cent of the cost reduction of hydrogen delivered to the user.

Hydrogen in aviation

Today's aircrafts fly on standard jet fuel (kerosene), which emits 3.15 kg of carbon dioxide per kg of fuel. This translates to about 360 tons of carbon for a ten-hour trip with a Boeing 747, and the whole sector emits around 3 per cent of global carbon emissions, or about 0.75 million tons, per year[8].

Kerosene is the ideal fuel for flying: it is both extremely light, measured by its energy content, as well as dense, requiring little volume to store that energy. Conversely, it is extremely difficult to electrify a plane. For short-haul flights in small airplanes (up to 20 passengers), hydrogen and fuel cells are a viable option and are indeed trialled today. Most emissions in aviation, however, stem from long-haul flights.

For the large aircrafts used on these routes, the most realistic decarbonisation option is to replace kerosene from fossil sources with kerosene that does not bring new carbon into the atmosphere. One option is to use biofuels (bio-kerosene); another is to produce synthetic kerosene from hydrogen. Synthetic fuel is a liquid fuel derived from a blend of hydrogen and carbon monoxide, for which hydrogen and a carbon feedstock are needed. Since bio-kerosene and synfuel are chemically similar to conventional kerosene, they can be 'dropped into the fuel pool' and stored, transported and used like conventional kerosene. That makes the transition to these fuels easier, as existing infrastructure and aircrafts can be used.

Compared to kerosene, synfuels and biofuels are more expensive. Today, kerosene costs approximately USD 0.50 per litre, while biofuels cost USD 1.20 to 1.50[9] and hydrogen-based synfuel costs USD 2 to 2.30 per litre, depending on the source of carbon.

[8] Air Transport Action Group (2018).
[9] Pavlenko, N., Searle, S., and Christensen, A. (2019).

To make synfuel truly carbon neutral requires that carbon is sourced from a carbon-neutral source. This can be achieved by taking carbon directly out of the atmosphere using direct air capture. Carbon can also be sourced from biomass, for instance through CCS of a biomass gasification plant. If the carbon is captured from an industrial process and used to make synfuel, which is the lowest-cost alternative, it is eventually emitted into the atmosphere, adding to the total carbon in the atmosphere. This is the re-use of carbon and, while lowering total emissions, is not a zero-carbon method.

Cost competitiveness. As Exhibit 25 shows, as hydrogen production costs drop, synfuel could become cost competitive with bio-kerosene as early as 2030 when using carbon from an industrial process. Given a biofuel cost of USD 1.50 per litre, hydrogen must reach a cost of USD 2.70 per kg to become competitive with biofuels.

If the synfuel is based on direct air capture of carbon, a hydrogen cost of USD 1.80 per kg is required to outcompete bio-kerosene. This will be feasible by 2030 in regions with good resources for hydrogen production.

Competitiveness with conventional kerosene requires a certain carbon cost. For instance, paying USD 1.50 per litre extra for low-carbon fuel rather than conventional kerosene would add approximately USD 120 per passenger on a flight from London to New York. By 2030, the cost of abating 1 ton of carbon through synfuels will be around USD 300 when using hydrogen from low-cost production sites and direct air capture at around USD 90 per ton.[10] Switching to carbon from industrial processes lowers the cost of abatement to about USD 200 per ton of CO_2. In the long run, with hydrogen costs nearing USD 1 per kg, the abatement costs are reduced to around USD 150 with direct air capture at USD 60 per ton of carbon.[11]

Cost development. There are three main cost drivers of hydrogen-based synfuel. The first and most important cost driver is the cost of hydrogen feedstock, for which the cost trajectory is discussed in Chapter 2. Carbon feedstock is the second important cost driver and the cost depends greatly on the source of carbon. Carbon feedstock from industry processes based on fossil fuels or biomass is estimated to cost USD 30 per ton of carbon. Direct air capture costs are comparatively high as the technology is not fully developed, estimated at USD 160 per ton of CO_2 today. The cost of direct air capture is expected to decline by about 40 per cent until 2030 as the technology matures, reaching USD 90 per ton of carbon. The third important cost element is the fuel synthesis plant itself; a cost-reduction potential of about 40 per cent is estimated for the plant itself from 2020 to 2030 due to scaling up plant capacity.

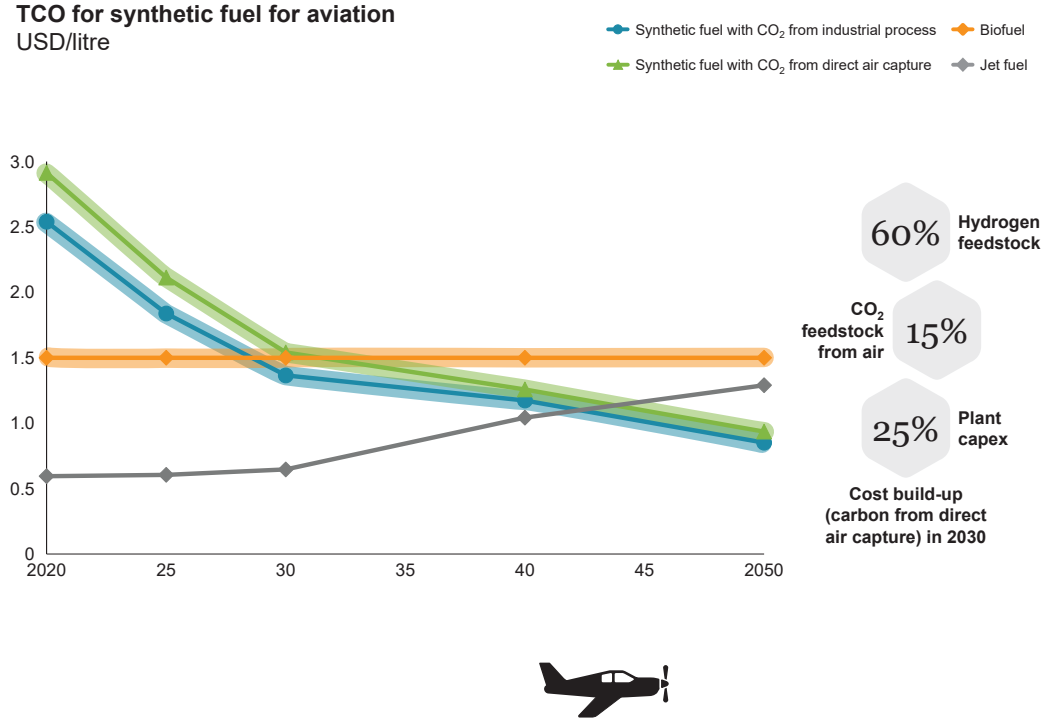
For small aircrafts, hydrogen can also be used directly in fuel cells instead of converting it into synfuel. This is currently being tested in planes of up to 20 passengers and ranges up to 800 km, as well as VTOLs (vertical take-off and landing) and smaller drones. In small aircrafts, hydrogen is attractive, as the equipment being replaced – turbines – is relatively expensive (a small turbine costs between USD 0.5 million to 1 million) and requires frequent maintenance.

Furthermore, smaller plane operators do not have access to kerosene at the same prices as large airlines, resulting in more expensive fuel. Fuel cell planes theoretically require less maintenance as they do not produce heat and vibration like turbines. They are also significantly less noisy and can offer a better flying experience.

[10] Fasihi, M., Efimova, O., and Breyer, C. (2019).
[11] IRENA (2019a).

EXHIBIT 25 | Cost of synthetic fuel

TCO for synthetic fuel for aviation
USD/litre



Hydrogen ships

The maritime sector today emits approximately 2.5 per cent of global carbon emissions, equivalent to 940 Mt per year.[12] The International Maritime Organization (IMO) has committed to reducing emissions by 50 per cent or more by 2050,[13] and there are several pathways to decarbonisation. They include replacing current bunker fuels with LNG, and using liquid ammonia or hydrogen-based synfuels instead of burning marine fuel on larger ships and hydrogen fuel cells in smaller ones. LNG is likely not the preferred long-term option – while cleaner than marine diesel, it does not offer zero-emission performance. However, it can serve as a transition mechanism until technologies emerge that make hydrogen-based fuels more economically attractive.

Cost competitiveness. Exhibits 26 and 27 below show the competitiveness trajectories projected for regional ferries and RoPax (combined roll-on/roll-off vehicles and passenger ferries). For smaller ships with motor power requirements under 2 megawatts (MW), like passenger ferries or ferries with room for fewer than 100 cars, hydrogen fuel cells offer a potential alternative for the near term. In fact, hydrogen can serve as a competitive low-carbon alternative to electric ferries before 2030, as the latter requires expensive large batteries and associated charging and infrastructure. Competitiveness varies by region and exact location due to a number of factors such as existing infrastructure, cost of electricity and hydrogen fuel, and operational factors such as distance and sailing schedule. Hydrogen passenger ferries are particularly competitive in situations where there are short docking times that do not allow enough time for charging the battery. In such situations, the ferry operator may need to purchase additional battery electric ships to maintain the required service level, nearly doubling the TCO. Fuel cell ferries are also attractive alternatives where the grid connection is weak, requiring either significant upgrades to enable fast charging of the ship battery or an onshore battery to charge the ship, which are both expensive solutions.

For larger ferries with motor power up to 4 MW, hydrogen can be an attractive low-carbon alternative. Batteries are unlikely to be suitable due to the high cost, weight, and volume of the battery required for ships of this size and fuel consumption. Therefore, the low-carbon alternative is biodiesel, which is expected to be more competitive until 2030. However, the hydrogen fuel cell ship could become competitive by 2035, as the cost of fuel cells and hydrogen fuel declines following scale-up of other mobility segments such as trucks and passenger vehicles. The cost of fuel plays a larger role for larger ships such as the RoPax than for the smaller passenger ferries, so competitiveness is highly sensitive to the cost and availability of biodiesel. This means that cost competitiveness with conventional marine diesel is more challenging. The RoPax requires a cost of carbon of USD 80 to 150 per ton of CO_2e to outcompete diesel in 2030, while the passenger ferry requires only USD 50 to 100 per ton of CO_2e.

Cost development. The cost drivers for fuel cell ships are similar to those of other mobility segments such as cars, trucks, and trains. Due to the high importance of fuel for the ship operator TCO, the majority of the cost reductions are driven by lower-cost hydrogen fuel, accounting for more than 90 per cent of the reduction in cost until 2030.

[12] European Commission (2019).
[13] International Maritime Organization (2019).

For longer-distance shipping involving, e.g. large container ships, ammonia fuel may offer the most viable low-carbon option. This solution usually involves a modified engine similar to today's technology but requires less modification overall than with the use of a fuel cell. While using liquid hydrogen is also possible in theory, its relatively low energy density of 2.4 kilowatt-hours per litre (kWh/l) compared with ammonia's 3.5 kWh/l likely makes it less attractive. Liquid hydrogen also requires extremely low temperatures to remain liquid (–252.87°C versus –33.6°C for ammonia) and boil-off can be a problem on longer routes, especially in the presence of 'sloshing'. For these reasons, ammonia likely offers a more attractive alternative for ship bunker fuel. Furthermore, the conversion of hydrogen to ammonia is a well-established and low-cost process, and ammonia would be a low-cost option if used directly. As discussed in Chapter 2, the reconversion of ammonia is expensive and energy intense, but ammonia as shipping fuel is feasible as the ammonia can be used directly as fuel.

Exhibit 26 | TCO development of regional ferry

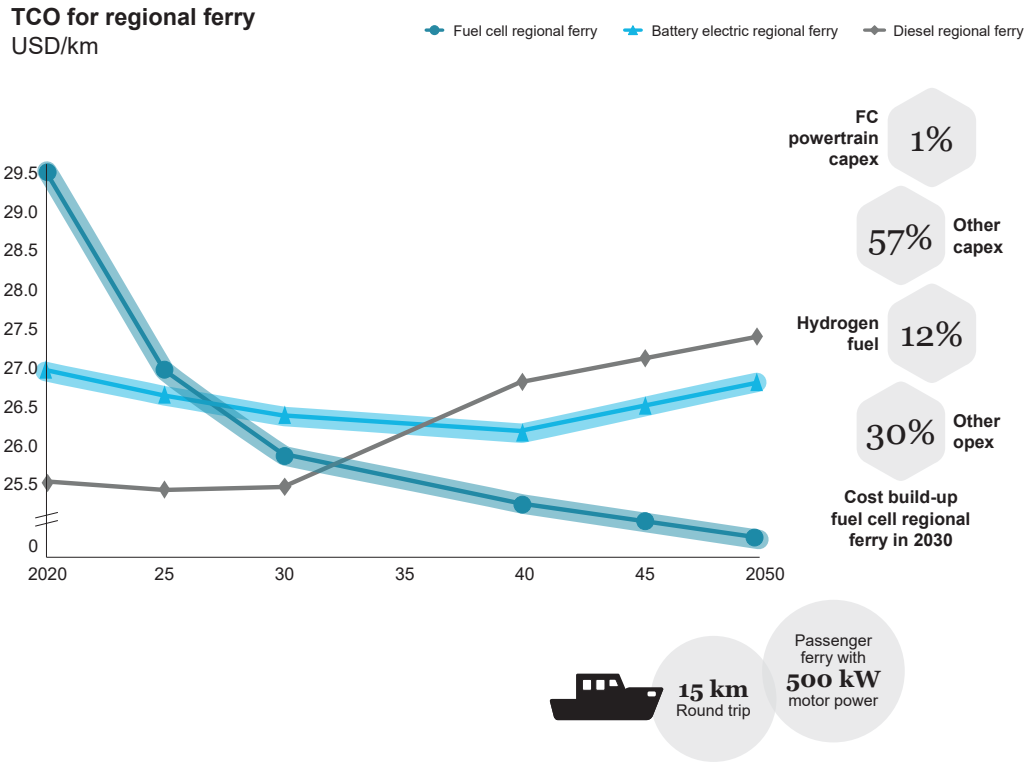
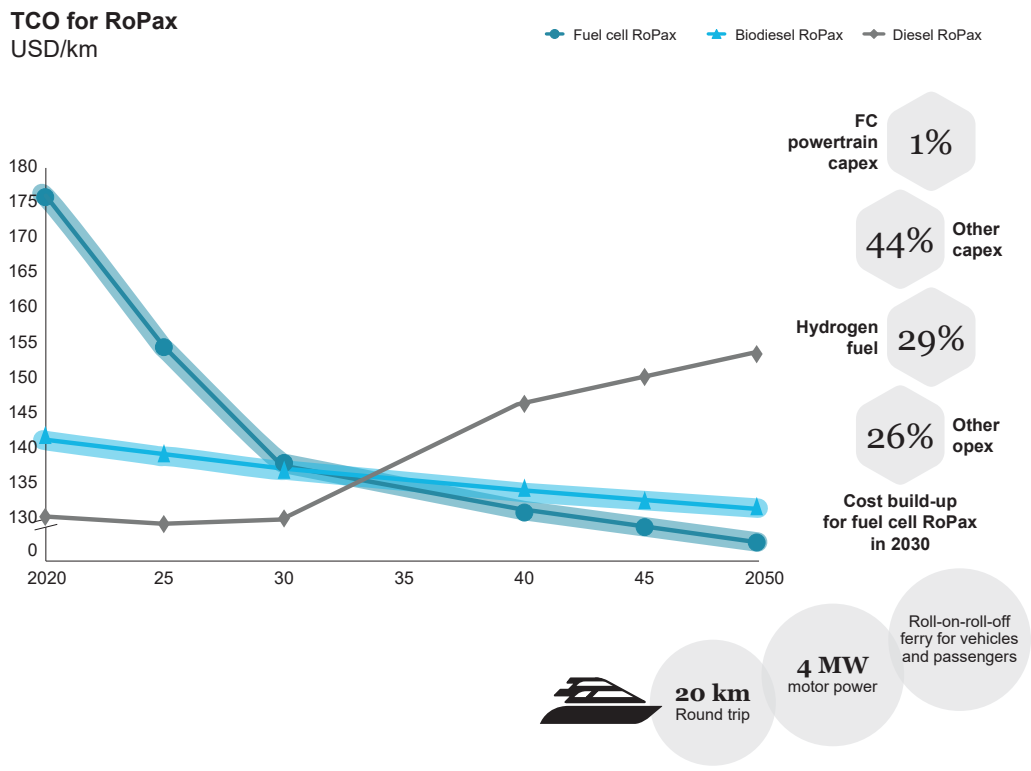


Exhibit 27 | TCO development of RoPax



Heat and power for buildings

Heat and power for buildings represents over a third of global energy demand (118 EJ) and a quarter of global carbon emissions (8.67 Gt of CO_2).[14] The sector has proven difficult to decarbonise, particularly for heating where only a few low-carbon alternatives exist to compete with natural gas (the most common heating fuel). Of these limited options, hydrogen solutions are among the most cost-effective and flexible ways to facilitate the sector's energy transition. The following section explores the potential competitiveness of hydrogen boilers for home heating and fuel cell CHPs.

Boilers for heating

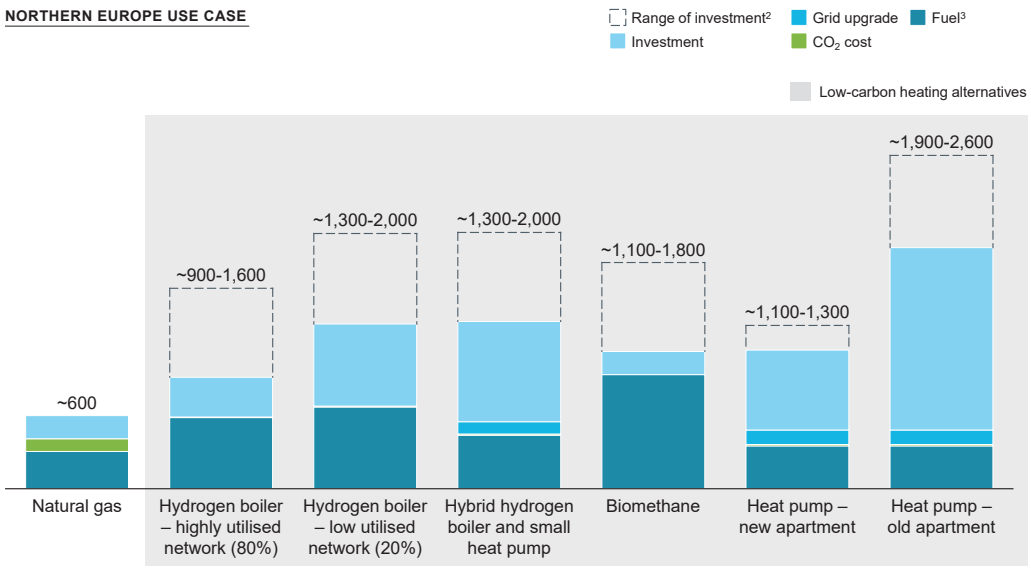
Hydrogen in gaseous form can provide a low-carbon alternative to natural gas heating as it can largely utilise the same infrastructure network – from pipelines to the boilers themselves.

Cost competitiveness. Hydrogen boilers can be the most attractive solution to providing low-carbon heating to residential building in regions with existing natural gas infrastructure. Competitiveness is driven in large part by the falling cost of hydrogen production and boiler capex, and by hydrogen's ability to utilise the natural gas pipeline. The cost of hydrogen boilers could fall to about USD 900 to 1,600 per household per year by 2030, similar to natural gas boilers. This would put hydrogen-based heating on par with biomethane solutions and heat pumps for new buildings. Notably, hydrogen-based heating would also become more competitive than heat pumps for older buildings, which incur significant refurbishment costs in implementation (Exhibit 28). Notice that the ranges on these estimates are large, as TCO can fluctuate due to several factors, such as local climatic conditions, exact infrastructure upgrades required and ranging costs of accompanying home retrofits.

[14] Figures from 2017, IEA (2019b).

Exhibit 28 | Cost components of residential heating solutions in 2030

Household heating
USD/year per household in 2030[1] (consumption 10 MWh/year)



1. One household is assumed to consume 10 MWh of heat per year
2. Range due to different state of insulation in building (new vs. old)/grid infrastructure requirements from high heat pump penetration/cost and utilisation of hydrogen network
3. Fuel cost varies by resources available; can be lower or higher than shown here

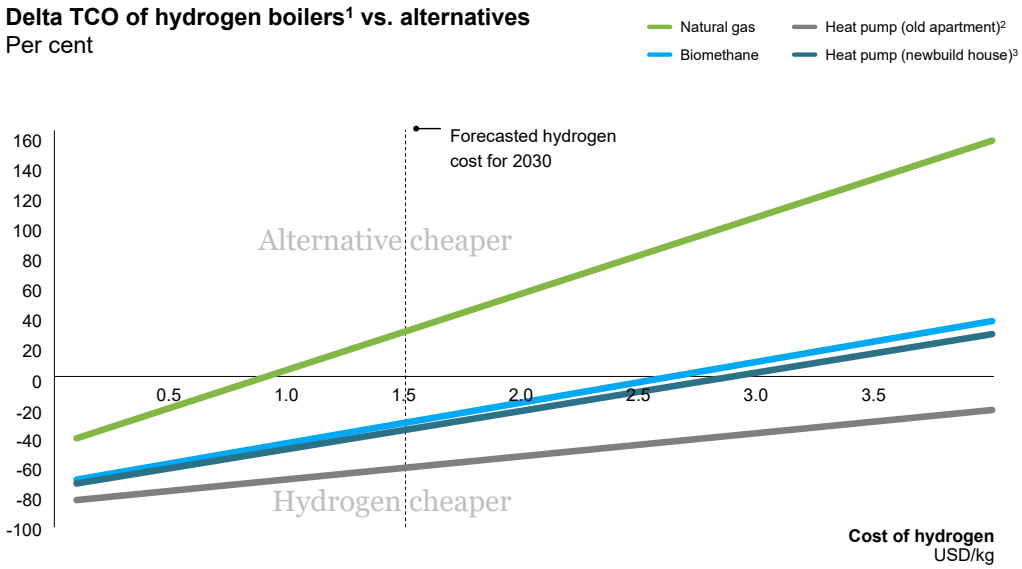
Hydrogen heating cost depends heavily on the utilisation of existing natural gas pipelines, at a rate of 90%.

In contrast, the cost of heat pumps is strongly impacted by the refurbishment cost: low- to no-cost for new builds but substantial for old apartments.

As detailed in earlier chapters, the falling cost of hydrogen supplied will be a key driver of competitiveness across applications. This is evident in the cost trajectory for hydrogen boilers: it outcompetes heat pumps for refurbished residences when hydrogen's cost falls to USD 5.4 per kg, and it can beat biomethane and heat pumps for newly built houses as hydrogen costs drop to approximately USD 3 per kg. This presents a clear production cost target for future heating networks.

However, none of the low-carbon options are likely to outcompete natural gas on cost alone. As shown in Exhibit 29, hydrogen boilers can only break even with natural gas heating if the cost of hydrogen falls to under USD 1 per kg. A regulatory push to support low-carbon technologies will be critical. There are already several similar initiatives underway in the US, Canada, the UK and the Netherlands, among others.

Exhibit 29 | Break-even cost of hydrogen at which H_2 boilers outcompete alternatives



1. Assumes partial use of an existing natural gas network
2. Refurbishment included in cost of heat pump for old apartment
3. No refurbishment required

SOURCE: H21; DoE; Element Energy

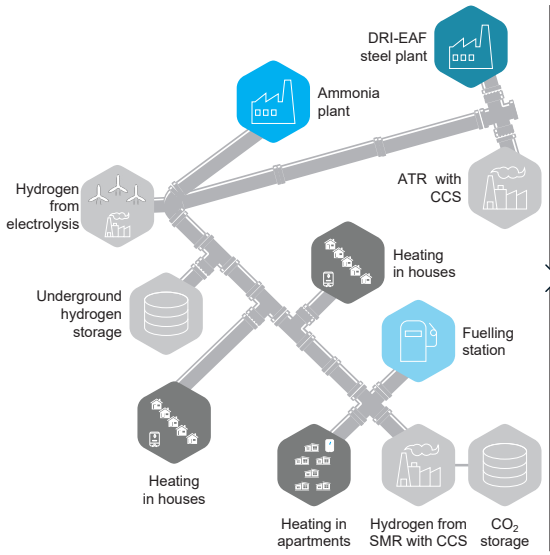
Cost development. In addition to the costs avoided by not building new infrastructure, developing a hydrogen-based heating network using the existing natural gas network provides other cost-reduction benefits that biomethane and heat pump solutions cannot necessarily offer.

First, hydrogen's ability to leverage the existing natural gas network ensures the value of the existing pipeline assets is not lost. Second, for hydrogen-based heating networks, higher utilisation drives down costs. The tipping point occurs once network utilisation reaches 80 per cent, and achieving this level is facilitated if an existing natural gas network can be accessed to which those users are already connected. Costs could fall even further if other industrial users and refuelling stations connect to the same network as shown in Exhibit 30. For example, adding two steel plants producing 500,000 tons of steel p.a. (56,000 tons of hydrogen per year each), the network cost per household is reduced by about USD 78, from USD 380 per year to around 300. In contrast, for heat pumps, increasing utilisation to 80 per cent would likely increase peak demand loads and put additional strain on the electricity grid. This would require additional grid upgrades which would increase the cost of heating for each household further.

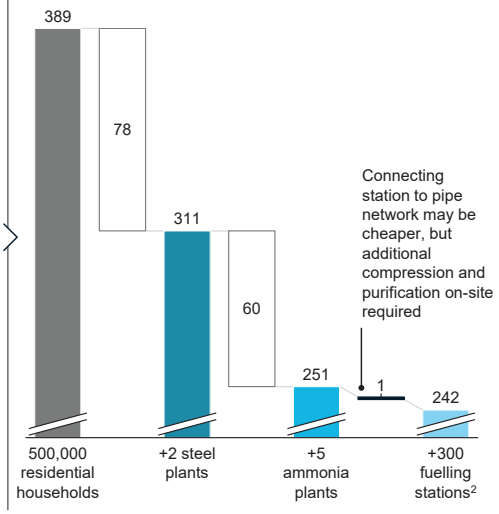
Lastly, though not directly related to cost drivers, a hydrogen pipe network can provide line pack hydrogen storage, allowing peaks and troughs in demand to be more effectively managed. Used in conjunction with power-to-hydrogen, this can support the transition towards lower-carbon hydrogen production, as it compensates for part of the variability of renewable energy sources. Due to the lower density of hydrogen, this is primarily viable in the transmission network.

Exhibit 30 | Example hydrogen pipeline network

Hydrogen pipeline network schematic



Cost of network as additional users connect
USD/year per apartment[1]



1. Considers apartments in North of England consuming 10 MWh/year, with total H_2 flow of 176,000 ton/year covering 500,000 apartments
2. 480 kg/day stations utilised at 60%, each stations required 0.5 km distribution pipeline at USD 280,000/km

SOURCE: H21; DoE

Finally, it should be noted that blending hydrogen into the natural gas grid is a potential transition alternative. For example, blending hydrogen at levels of up to 20 per cent into the natural gas network can be achieved without the need for major modification to pipes or household appliances, thereby incurring relatively minimal investment costs. Moreover, the safety risk remains essentially the same as for natural gas, and although not a fully low-carbon solution, blending can potentially save significant amounts of CO_2 emissions. For a blending level of 5 per cent, 32 to 58 kg of CO_2 could be saved annually per household consuming 10 to 18 MWh per year; assuming 3.3 million households with natural gas heating, about 200,000 tons of CO_2 can be saved annually.

Fuel cells for combined heat and power

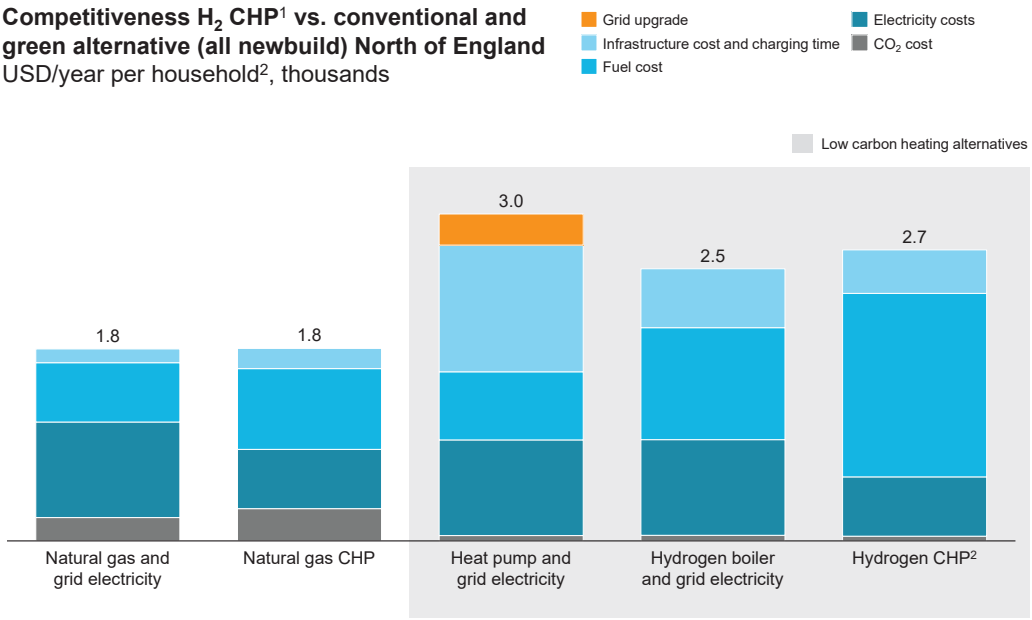
Hydrogen fuel cells for combined heat and power technology (FC CHP) is another low-carbon alternative that generates electricity from fuel cells and then recovers and uses the by-product heat for hot water, space heating, and/or cooling in residential and commercial buildings.

Cost competitiveness. FC CHP was compared to both low-carbon (hydrogen boilers and heat pumps with grid electricity) and natural gas (boiler plus grid electricity and natural gas CHP) alternatives for the case of a new-build home in the north of England, having a total area of 120 m2 and consuming 7.5 MWh of electricity and 18 MWh of heat per year. The findings suggest FC CHP can be a viable alternative to hydrogen boilers and heat pumps by 2030 when the cost of hydrogen is approximately USD 1.9 per kg. As shown in Exhibit 31, the FC CHP total cost per household per year would be USD 2,700, falling between the slightly lower-cost hydrogen boiler and slightly higher-cost heat pump option when factoring in necessary grid upgrades.

The specific low-carbon heating solution that is most cost effective will depend on the heat and electricity demand profile, locational energy costs and actual prices of equipment. However, all low-carbon options will struggle to compete with natural gas solutions for home heating, for which the annual costs are only USD 1,800 per household.

Exhibit 31 | Cost competitiveness of fuel cell CHP vs alternatives

Competitiveness H_2 CHP[1] vs. conventional and green alternative (all newbuild) North of England
USD/year per household[2], thousands



1. We system (30% electrical efficiency; 80% overall efficiency)
2. Assumes new build house with 18 MWh heat and 7.5 MWh electricity consumption – Note that fuel and electricity costs will vary due to specific local conditions

SOURCE: H21; DoE; Element Energy; SGC Rapport 2014; Eurostat; IEA; Battelle Memorial Institute

Cost development. Cost-reduction potential for hydrogen FC CHP is driven mainly by lower hydrogen production costs, with some contribution from cheaper CHP systems and reduced electricity cost over time. A flatter annual heat load curve and/or a closer match between heat and electricity load over the course of the year will also tend to improve the utilisation factor and therefore, the economics of CHP, but analysis of time series data shows that the peak-median load ratio does not vary greatly across property types, so the effect is unlikely to be significant.

Heat and power for industry and the grid

Hydrogen can provide industry heat as well as power for grid and off-grid demand. Several specific use cases are covered in the cost assessment, including medium- and high-grade heat, flexible simple cycle hydrogen turbines for peaking capacity, combined cycle hydrogen turbines for baseload as well as fuel cell generators for backup and remote power.

In thermal applications, hydrogen competes with conventional fossil fuel heat sources on a heat-value basis. This leads to a low hydrogen production break-even cost of about USD 1.10 per kg versus average natural gas prices (roughly USD 7 per million British thermal units, or MMBtus) at USD 50 per ton of CO_2. Such low hydrogen production costs will likely only occur only in the most optimal locations. However, when compared with other low-carbon options, several use cases are possible where hydrogen would become the lowest-cost decarbonised solution available at scale. These include high-grade heat for industrial processes that do not allow for electrification, peaking capacity for the power grid, and remote power generation in regions with high diesel prices and/or non-optimal renewables conditions. In the long term, full competitiveness with conventional alternatives will be achievable if CO_2 costs exceed USD 100 per ton.

Power and heat applications offer an easily expandable demand segment for hydrogen that could support the scale-up of the production industry, which will drive down costs for all other segments. Applying hydrogen in heat and power can also help regions increase their energy autonomy and reduce industry-related emissions of fine particulate matter and other pollutants.

Industrial heating

Industry heat is classified into three temperature ranges: low-grade heat up to 100°C, medium-grade heat of 100 to 400°C and high-grade heat that exceeds 400°C. Today, fossil fuels (coal, natural gas) and electric power (resistor heating or heat pumps) primarily cover demand for industrial heat. Decarbonisation options include direct electrification, biomass or fossil fuels plus CCS.

Cost competitiveness. For low-grade heat, electrification is the lowest-cost decarbonisation option; therefore, hydrogen will likely not play a significant role. For mid- and high-grade heat, biomass is an option, but faces supply constraints in several regions. CCS, for example, only works in regions with access to CO_2 storage; but where biomass or CCS are not options, hydrogen and electric heating are the only two low-carbon solutions for mid- and high-grade heat.

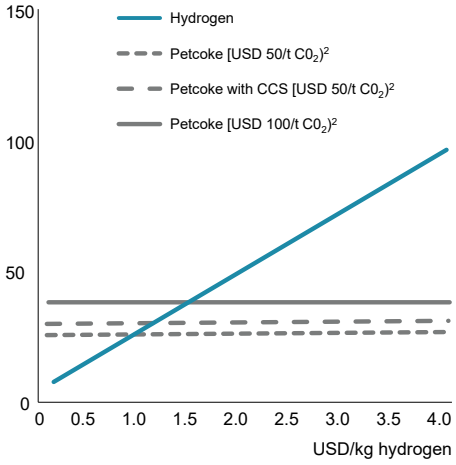
Since the heat demand patterns differ from application to application, no one-size-fits-all solution exists. Hydrogen-based heating offers high flexibility and is thus well-suited for applications with intermittent heat demand.

The competitiveness of hydrogen with conventional and other low-carbon solutions is mainly determined by fuel costs, as shown in Exhibit 32. Hydrogen cost will correspond to 80 to 90 per cent of the total cost for providing heat via hydrogen burning by 2030. Comparing hydrogen to other energy carriers on a pure heat-value basis shows that its cost needs to decline below about USD 1.10 per kg to be competitive with natural gas or coal in 2030, assuming USD 50 per ton of CO_2. This figure increases to USD 1.50 per kg if the resulting CO_2 cost reaches USD 100 per ton, while hydrogen should reach a break-even point with biomass at USD 2 to 3 per kg (depending greatly on local resources and supply of biomass).

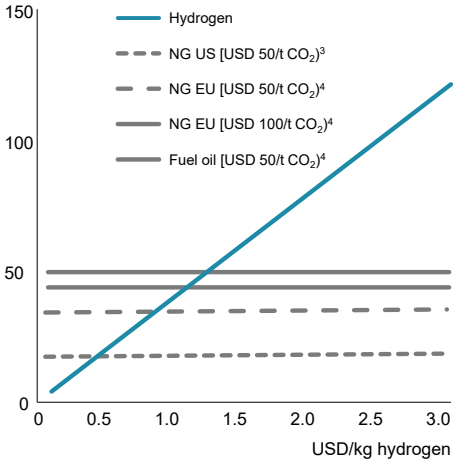
Cost development. Because the price of hydrogen will mainly determine the cost for heating, the two major drivers for cost competitiveness will be the CO_2 cost and low hydrogen production costs. Thus, to achieve long-term competitiveness and full decarbonisation, regulation needs to enforce an implicit CO_2 cost mechanism and potentially other support options. In addition, access to low-cost, low-carbon or renewable hydrogen production will be crucial for early competitiveness, while scale deployment represents a minor point for heat applications due to the limited impact of capex on the total cost.

Exhibit 32 | Competitiveness of hydrogen in example use cases in high- and medium-grade heat

High-grade heat: cement production hydrogen vs. alternatives
USD/ton cement



Medium-grade heat: PTA production hydrogen vs. alternatives
USD/ton PTA



1. Expected hydrogen cost from ATR with CCS in 2030: US USD 1.06/kg, EU/Germany USD 1.68/kg, Japan/Korea USD 1.82/kg
2. Petcoke cost of USD 0.10/kg
3. US NG cost of USD 0.12/kg
4. EU NG cost of USD 0.31/kg
5. Fuel oil cost of USD 0.39/kg

Turbines for grid power generation

Hydrogen can also fuel power generation for the grid. Power systems must fulfil two key requirements: 1) provide energy and 2) provide flexible capacity to ensure stability and resilience. Today, thermal generation via fossil fuels mainly provide energy, but the deployment of renewables is replacing thermal generation at an increasing pace – wind and solar already account for more than 50 per cent of new capacity additions.[15] With a growing share of variable renewable generation, the importance of flexible generation capacity increases. Today, flexible capacity comes mainly from fossil fuel generation and (pumped) hydro where feasible. Batteries are an option for short-term flexibility (typically 2 to 4 hours) with a high number of cycles per year (more than 300). Hydrogen turbines also offer a way to provide balance and flexibility to the grid, as stored hydrogen can be used to generate low-carbon or renewable electricity whenever the need is highest.

[15] McKinsey Global Energy Perspective, McKinsey & Company (2019).

Cost competitiveness. In tomorrow's low-carbon energy system, hydrogen-based power generation can play a role in both energy supply ('baseload') and flexible capacity. For low-carbon baseload energy supply, hydrogen is only relevant in regions constrained in renewables potential and situations where alternatives like fossil fuels with direct CCS or biomass (wood chips or biogas) are not an option. In such cases, companies could import hydrogen and use it to power hydrogen turbines.[16] For an assumed import price of USD 3 per kg of hydrogen, the cost is about USD 140 per MWh for the resulting power generation.

In contrast, hydrogen should play a major role in providing flexible capacity in a low-carbon power system both for short-term multi-hour balancing (simple cycle peak plant) and multiday or week generation via combined cycle gas turbines (CCGT) at times when renewables generation is low. In this way, hydrogen can act as a buffer and long-term storage option for the power system.

The storage of large hydrogen volumes is feasible at a low cost (cavern-based storage is expected to reach about USD 0.30 per kg of hydrogen) and in contrast to batteries, the impact of storage time on overall cost is more limited. Consequently, hydrogen should offer advantages over batteries, especially for longer storage durations of more than five hours up to days or even weeks. The main drawback of this power-to-gas-to-power route if electrolysis is used for hydrogen production is the round-trip efficiency, which is around 45 per cent.

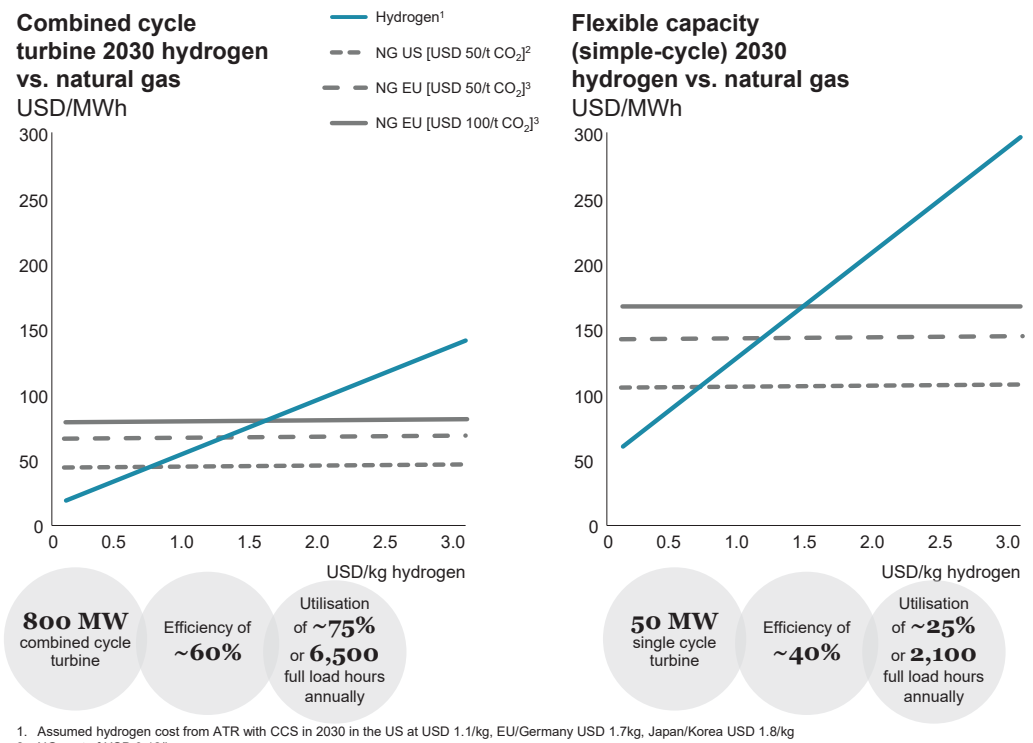
Cost development. As with industrial heat applications, hydrogen cost drives around 80 per cent of the total power generation cost, as shown in Exhibit 33. Thus, after industry proves its technical feasibility (demonstration projects for pure hydrogen are on the way in the Netherlands,[17] and the capex of hydrogen turbines should rival that of natural gas turbines by 2030), access to low-cost hydrogen will play a critical role in enabling hydrogen-based power generation. As a transition solution, blending hydrogen with natural gas in existing turbines can enable as much as a 10 per cent CO_2 reduction (for 30 per cent hydrogen volume). The fundamental economics for hydrogen break-even cost in this blended case are the same as for pure hydrogen power generation.

The economics can be illustrated through the following example. Hydrogen generation from low-cost renewables at USD 25 per MWh with a capacity factor of 50 per cent yields a cost of USD 1.70 per kg of hydrogen produced. Storing this hydrogen underground will add about another USD 0.30 per kg, thus the hydrogen costs USD 2 per kg. If this hydrogen is used to generate power, the resulting cost is USD 100 to 200 per MWh. In ideal conditions (e.g. a CCGT turbine at 60 per cent utilisation), the cost is USD 100 per MWh, while simple-cycle turbines at 25 per cent utilisation would deliver power at USD 200 per MWh. This example illustrates the cost penalty per MWh associated with the power-to-gas-to-power route.

This analysis delivers two key insights. One, companies should use hydrogen-based power for high-value flexible generation first, and two, hydrogen baseload power generation for deep decarbonisation in situations with constrained renewables potential will require strong policy support.

[16] Hydrogen-powered gas turbines is assumed in this analysis. In theory, fuel cells also allow for stationary power generation. The final choice of technology will be determined by the cost trajectory of the two alternatives.
[17] Mitsubishi Hitachi Power Systems (2018).

Exhibit 33 | Hydrogen-based power generation vs. natural gas



1. Assumed hydrogen cost from ATR with CCS in 2030 in the US at USD 1.1/kg, EU/Germany USD 1.7kg, Japan/Korea USD 1.8/kg
2. NG cost of USD 0.12/kg
3. NG cost of USD 0.31/kg

Generators

Today, generators are primarily based on diesel, emitting approximately 700 kg of CO_2 per MWh of power generated. Generators can also be based on natural gas, which emit comparatively less carbon and particles than diesel-powered ones. Biofuels, batteries with renewable electricity, and hydrogen fuel cells with low-carbon or renewable hydrogen production are all alternatives to decarbonise generators. Generators are used as backup power where it is important to secure operations under all conditions, e.g. in hospitals or data centres. They are also used for power generation in remote locations, e.g. to power telecom towers or buildings that are far from the electricity grid.

Hydrogen fuel cell generators are viable alternatives for backup power generation, e.g. in hospitals, and for power generation in remote locations where batteries and renewables are unviable due to sub-optimal conditions for renewable power generation. In areas where the conditions for renewable power generation are good, a battery for storing the energy may be the lowest-cost low-carbon alternative. Alternatively, it is possible to generate hydrogen on-site with renewables and potentially export the excess production.

Cost competitiveness. Two use cases are considered for generators: backup power and remote power generation. In the case of a 1 MW backup generator for a hospital, the fuel cell generator outcompetes battery backup storage. This is driven by much lower capital expenditure for the hydrogen system than for the battery and the low assumed utilisation of less than 2 per cent per year of such a system.

In the case of remote power generation, a telecom tower that requires a continuous power supply of 5 kW is analysed. In this use case, the cost of fuel is the most important driver due to the high utilisation, and the cost competitiveness depends greatly on location and cost of battery and renewable power. Hydrogen is best suited where the conditions for on-site renewable generation are sub-optimal. For instance, the hydrogen alternative is more than 40 per cent lower cost than a solar plant and battery in Edinburgh. When considering the case of remote power generation in southern Spain, the hydrogen fuel cell generator is about 30 per cent more expensive than the battery and solar power plant setup in 2030. A hydrogen cost of USD 6 per kg delivered to a very remote location is required to break even, which may be challenging to achieve.

For a backup generator to outcompete the diesel generator purely on cost is difficult due to the higher capital expenditure on the fuel cell and tank system and higher fuel costs. In 2030, the cost of the system is two times higher for the hydrogen compared to diesel. Given a hydrogen cost of USD 3 per kg delivered, a carbon cost of USD 200 per ton is required to make the fuel-cell-based generator competitive.

Cost development. There are two main factors influencing the cost of hydrogen generators; first, the cost of the fuel cell and tank system, and second, the cost of hydrogen production and distribution. The cost of fuel cell and tank system is of more importance for the backup generator case due to the low system utilisation. Similarly, the cost of hydrogen fuel supplied matters more for the remote generator system due to higher system utilisation provided by the steady power demand of the telecom tower.

The cost of fuel cells and hydrogen tanks are projected to decline by up to 70 per cent by 2030, driven by larger market volumes of fuel cells and tanks across several applications, such as within transportation. The fuel cell system used is similar across different applications, with some variation in the fuel cell balance of plant, which is generally less costly for larger-scale applications. The cost reduction of fuel cell and tank systems accounts for about 50 per cent of cost improvement of the backup generator and only about 10 per cent for the remote generator system.

The cost of hydrogen supplied is projected to decline by about 20 to 40 per cent, as discussed in more detail in Chapter 2. The relative cost reduction is lower for the remote power generation use case due to the long-distance distribution required, indicating that cost reductions within production are less impactful on total cost decline. For the remote generator, the hydrogen fuel cost improvement translates to about 90 per cent of total cost reduction between 2020 and 2030, underscoring the importance of fuel cost for applications with high utilisation.

Industry feedstock

Over 90 per cent[18] of the hydrogen consumed today is used as industrial feedstock, with a large majority produced from fossil fuels. Processes such as the production of ammonia and methanol as well as refining require hydrogen, thus the only way to decarbonise is to change the source of the hydrogen molecules from grey to the low-carbon and renewable routes.

For new hydrogen feedstock applications, low-carbon steel-production based on hydrogen direct reduced iron (H2-DRI) was compared with other low-carbon alternatives and the conventional steelmaking process.

Industrial feedstock users can guarantee large-scale offtake and enable scale in the hydrogen production industry. For example, an ammonia plant that produces 1 Mt of ammonia per year consumes 200 kilotons of hydrogen. To produce this hydrogen would require 1.7 GW of electrolyser capacity, assuming a 50 per cent utilisation factor. A plant of such scale would likely take up much of the short-term electrolyser manufacturing capacity and could play a key role in the needed scale-up in production. Furthermore, such projects often involve few entities in the decision-making process and do not require a system change, which can accelerate uptake compared with the distributed usage characteristics common in segments like mobility or space heating.

Across all feedstock applications, the key cost-reduction driver is the production cost of hydrogen, which was discussed earlier in Chapter 2. The cost of carbon imposed on conventional alternatives provides an additional competitiveness driver for hydrogen. Its ultimate cost will result from the location of hydrogen production and the resources available, which could involve renewables or natural gas and carbon storage resources.

In regions such as the US, the Middle East, and Southern Europe, existing low-carbon industry feedstock applications will likely break even with grey hydrogen, even with carbon costs well below USD 50 per ton. This makes industry feedstock an extremely attractive segment for low-carbon hydrogen deployment.

[18] Institute for Industrial Productivity (2019).

Existing industry feedstock applications

Ammonia production and refining

Both low-carbon hydrogen from reforming plus CCS and renewable hydrogen appear to be viable solutions for decarbonising ammonia production. About 80 per cent of the ammonia produced is used in the manufacture of fertilisers, with end products such as urea or NPK (nitrogen, phosphorous, and potassium fertiliser). Ammonia production today sources hydrogen via steam methane reforming (SMR) or coal gasification, which emits about 2.5 tons of CO_2 per ton of ammonia produced.[19]

Cost competitiveness. Producing ammonia from low-carbon or renewable hydrogen are both attractive options, and the lowest-cost alternative will depend on both the region and available resources, as discussed in Chapter 2. Green ammonia production comes at a higher initial cost, with around 70 per cent higher plant capex due to the need for an additional air separation unit for the nitrogen supply. However, this only results in an additional cost of about USD 20 per ton of ammonia produced and an increase of 7 per cent of the market price of ammonia, at USD 300 per ton. On top of this, making renewable hydrogen from electrolysis the sole source of hydrogen for an ammonia plant requires some form of storage to secure production and bridge times without production.

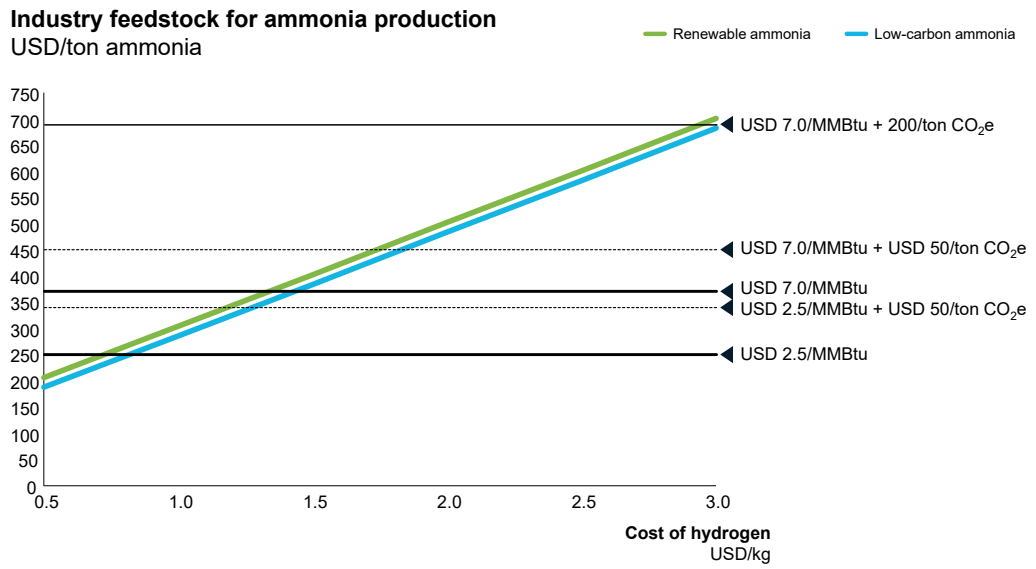
Cost development. The expected carbon cost drives the break-even point for low-carbon hydrogen using CCS, while the local price of natural gas drives the break-even point for renewable hydrogen against the usage of grey hydrogen. A natural gas cost of USD 2.50 per million British thermal units (MMBtus), such as in the US or the Middle East, yields a cost of ammonia of about USD 240 per ton. Breaking even requires a hydrogen cost of about USD 0.70 to 0.90 per kg (see Exhibit 34), which seems infeasible in the foreseeable future. However, with a cost of carbon of USD 50 per ton, the break-even point increases to USD 1.20 to 1.30 per kg for low-carbon hydrogen, achievable in regions with favourable renewables conditions or natural gas prices of about USD 3 per MMBtu.

In regions with higher natural gas prices of USD 7 per MMBtu, such as Europe, the cost of ammonia from conventional SMR is about USD 370 per ton. Breaking even with grey hydrogen requires low-carbon hydrogen costs of about USD 1.40 to 1.50 per kg, increasing to USD 1.70 to 1.80 per kg with a cost of carbon of USD 50 per ton. Increasing the cost of carbon to USD 200 per ton of CO_2e for the USD 7 per MMBtu scenario increases the cost of conventional ammonia to USD 690 per ton. In this case, low-carbon and renewable hydrogen would almost certainly be the lower-cost options across all regions, with a production cost of USD 3 per kg of low-carbon or renewable hydrogen required.

Refining is very similar to ammonia in terms of cost structure, as the two are based on SMR and hydrogen is the only effective decarbonisation option. The difference in cost lies in the additional air separation unit required for the ammonia, resulting in a slightly higher hydrogen break-even cost for ammonia (about a 5 per cent difference). Furthermore, the refinery can also use naphtha reforming to cover part of its hydrogen demand, potentially reducing the need for the storage of hydrogen that is produced from renewables.

[19] Institute for Industrial Productivity (2019), Plastics Europe (2019).

Exhibit 34 | Ammonia cost curve



Methanol production

Cost competitiveness. Methanol production from low-carbon hydrogen is competitive against grey at hydrogen costs of USD 0.80 to 1.50 per kg, depending on the region and the cost of natural gas, assuming no cost for carbon emissions. Including a hypothetical carbon price of USD 50 per ton increases the break-even cost of low-carbon hydrogen only slightly, by USD 0.10 to 0.20 per kg. These are steep targets for the production costs of low-carbon and renewable hydrogen. The cost of carbon has less influence on conventional methanol because methanol emits less CO_2 relative to natural gas feedstock, as around 70 per cent of the carbon is captured in the methanol end product.

Cost development. Methanol production requires two key input components – hydrogen and CO_2 – and is today mostly produced with hydrogen either from natural gas reforming or coal gasification. To produce methanol from renewable hydrogen from electrolysis, companies must add a source of CO_2 to the process. This CO_2 can come from a co-located industrial plant, which can supply the methanol plant instead of storing the carbon. The cost of the additional CO_2 feedstock depends on the cost of CCS and the cost of emitting the CO_2, and will vary according to local conditions and regulations. It is also possible to use carbon from biomass-based processes or base the CO_2 supply on direct air capture of carbon, which would result in truly low-carbon methanol. The latter alternative is currently costly, estimated at USD 150 per ton of CO_2.

From this perspective, methanol production from hydrogen and CO_2 qualifies as carbon capture and usage (CCU). Methanol is used in a variety of end products, ranging from formaldehyde for adhesives (about 30 per cent of the global market), to petrochemicals primarily for production of plastics (roughly a quarter of the market), and as a component in fuels (approximately 35 per cent of the market). If used as a fuel, carbon sequestration is brief, since it is released as the fuel is used. If the methanol helps to produce plastics or adhesives, carbon sequestration may be longer lasting. Consequently, many consider the latter application a 'better' end use than for fuels from a carbon emissions perspective. There are, of course, reductions in CO_2 emissions from not using conventional hydrogen production technologies due to lower process emissions, but the 70 per cent share of carbon captured in the methanol does not necessarily remain captured for long.

Low-carbon methanol production is less sensitive to carbon costs, resulting in a lower break-even point for hydrogen costs compared with ammonia. The analysis shows that a low-carbon cost of hydrogen of about USD 2 per kg supplied requires a cost of carbon of about USD 100 per ton for low-carbon methanol to break even. This suggests that ammonia or refining are initially more attractive use cases for low-carbon hydrogen feedstock. Considering a case based on direct air capture of carbon with a cost of USD 150 per ton of CO_2, the cost of methanol produced increases by about USD 200 per ton. A carbon cost of about USD 450 per ton is required to break even with grey production, given a low-carbon hydrogen cost of USD 2 per kg. Or, from a different perspective, if the cost of carbon were zero, the low-carbon hydrogen must be as low as USD 0.65 per kg.

New hydrogen applications: low-carbon steel production

Today, steel production is one of the world's largest emitters of CO_2, accounting for about 7 to 9 per cent of global CO_2 emissions from the global use of fossil fuels,[20] underscoring the importance of decarbonising this sector. The conventional alternative, a regular blast furnace, emits approximately 1.8 tons of carbon per ton of steel.[21] Hydrogen-based DRI could become competitive with both conventional blast furnaces and blast furnaces with CCS by around 2030, depending on the cost of coking coal in each region. H2-DRI was compared to a low-carbon blast furnace with 90 per cent CO_2 capture, and HISarna, a new process for producing steel from coal, also with a 90 per cent capture rate. Other hydrogen-based low-carbon alternatives are being developed, such as direct injection of hydrogen in the blast furnace, but these are not investigated here.

Cost competitiveness. The competitiveness of hydrogen-based steel production depends greatly on the cost of the hydrogen production and the cost of carbon when considering competitiveness with a conventional blast furnace.

Reaching lower costs than a blast furnace with CCS requires hydrogen costs of USD 1.80 to 2.30 per kg, with a higher break-even point in high-cost regions such as Europe or Japan. Compared with HISarna (with 90 per cent CO_2 capture), low-carbon hydrogen costs of USD 1.20 to 1.60 per kg are required to break even, with higher break-even levels in regions with more expensive coking coal.

Cost development. Competitiveness against conventional blast furnaces will largely depend on the cost of carbon. Given a cost of carbon of USD 50 per ton, H2-DRI can break even with hydrogen costs of about USD 1.60 per kg, assuming a cost of coking coal of USD 200 per ton. The implication is that even with average costs of hydrogen of about USD 2.30 per kg (achievable in several locations in 2030), H2-DRI solutions can outcompete blast furnaces with CO_2 costs of less than USD 100 per ton.

The benefit of using hydrogen from natural gas reforming plus CCS instead of coal-based production with CCS lies in that the process needs to capture less carbon, given that coal is twice as CO_2 intensive per energy unit as natural gas. If renewable hydrogen from electrolysis is used, no CO_2 capture is required at all. Using low-carbon hydrogen from reforming plus CCS yields the additional benefit of allowing decoupling of the location of the CCS and the plant itself.

[20] World Steel Association (2019a).
[21] World Steel Association (2019b).

Hydrogen industry scale-up requires **investment, policy alignment and market creation**

$70 bn

Investment required by 2030 to bridge the gap and make hydrogen competitive

4 | Implications: how to accelerate hydrogen's cost reduction and competitiveness

This is a pivotal moment for hydrogen.

As we demonstrate through the analysis contained in this report, hydrogen can become the most cost competitive, low-carbon solution for several specific use cases near-term, and it can quickly become so for many more. Urgent action is needed to achieve net-zero targets quickly, and hydrogen is a necessary part of the answer.

However, hydrogen's cost competitiveness can only be realised with sufficient policy support and investment to accelerate its scale-up. We recognise some progress has been made: governments are increasingly including hydrogen in their energy mix strategies and investment in numerous new projects have been announced. Yet, bringing hydrogen technologies to parity with other alternatives will require further action. We see three areas of needs: investment, policy alignment and market creation.

Need for investment

Achieving the scale-up and associated improvement in cost competitiveness discussed in this report requires additional investment. Reaching the scale required will call for funding an economic gap until a break-even point is reached – an investment to offset the initially higher costs of hydrogen as a fuel and of hydrogen equipment compared to alternatives. Instead of being perceived as costs, this should be seen as an investment to shift the energy system and industry to low-carbon technology.

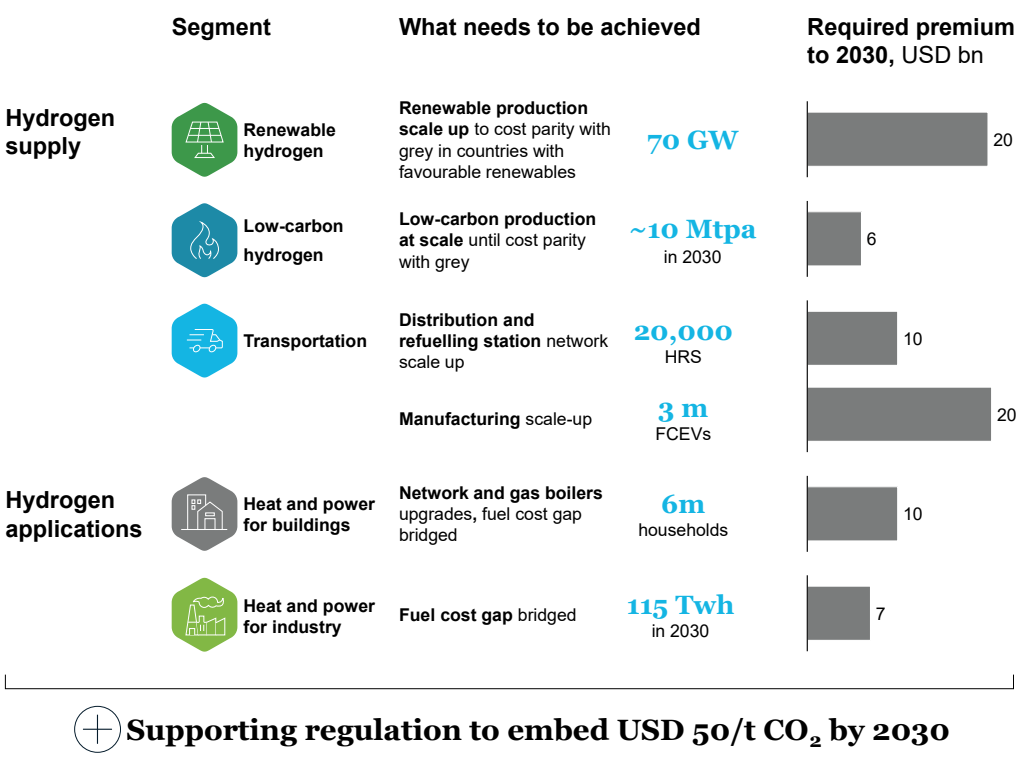
Consumers, industry, and governments can all help fulfil this premium. One prominent example of where initial support to close the gap for a sub-scale industry involved the application of feed-in tariffs and other compensation schemes used for solar PV and wind power, which led to cost competitiveness with fossil fuel alternatives. Similar compensation schemes could be envisaged for hydrogen.

The smart development and deployment of hydrogen can keep this cost premium manageable. We have identified six key areas where investments between now and 2030 would make the biggest difference (Exhibit 35).

In production, achieving competitive renewable hydrogen from electrolysis production requires about 70 GW of cumulative electrolyser capacity to be deployed over the next decade, with an implied economic gap to cover of roughly USD 20 billion. To get low-carbon hydrogen from fossil fuel reforming plus CCS off the ground, we estimate a gap of approximately USD 6 billion through 2030. In transport, the refuelling and distribution networks and the difference in costs for fuel cells and hydrogen tanks would mean a premium of an estimated USD 30 billion. In heating for buildings and industry, the cost difference between hydrogen and natural gas and investments to build the first hydrogen networks to heat about 6 million households amounts to approximately USD 10 billion through 2030.

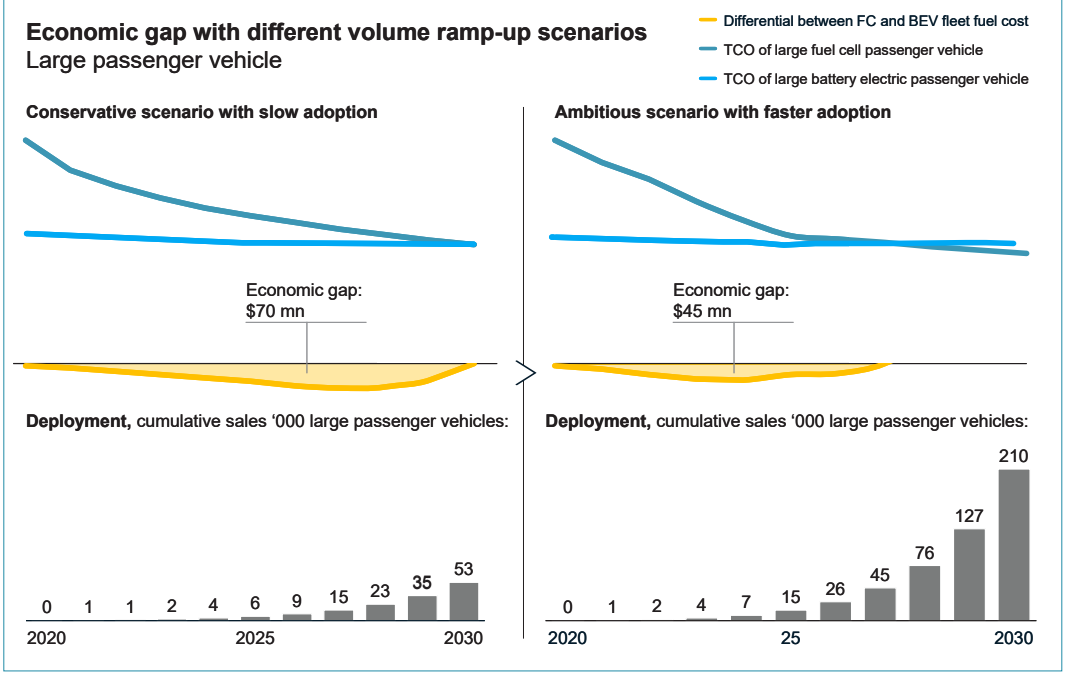
Granted, these are big numbers, but they pale in comparison to the amount the world currently spends on energy. In fact, they represent less than 5 per cent of the planet's total energy spend of USD 1.8 trillion in 2017 alone. By way of comparison, the annual support for renewables in Germany was USD 28 billion in 2019, of which about USD 10 billion were subsidies for solar energy. Even more drastically, fossil fuel subsidies are estimated to be over USD 60 billion in the EU in 2016. Stakeholders should find an equitable distribution of this investment across investors, businesses, and energy consumers – as all stand to benefit: meeting this break-even premium will open the door to global CO_2 emissions reductions of up to 6 Gt CO_2e per year.

Exhibit 35 | Cumulative economic support needed for hydrogen to reach break-even with low-carbon alternatives by 2030, USD billion



The economic gap is not a static number. In fact, the economic cost of scaling up hydrogen technology and applications to cost competitiveness is influenced by the speed at which cost-parity with competing low-carbon technologies is reached. Exhibit 36 shows a case in point for the supply of hydrogen to large passenger vehicles for private usage. The additional support required to supply large passenger fuel cell vehicles with hydrogen before parity with BEV is reached can be reduced by 35 per cent to USD 45 million with a faster volume ramp-up, as distribution network and station utilisation is optimized more quickly. This is true if the ramp-up of fuel cell vehicles is approximately 2.5 times faster until 2030. In this ambitious scenario the large passenger vehicle breaks even in 2027 instead of in 2030. The clear implication is that investing in hydrogen sooner rather than later will ultimately reduce the cost of transition and accelerate decarbonization of these respective segments.

Exhibit 36 | Economic gap with different volume ramp-up scenarios for large passenger vehicles



Need for policy alignment

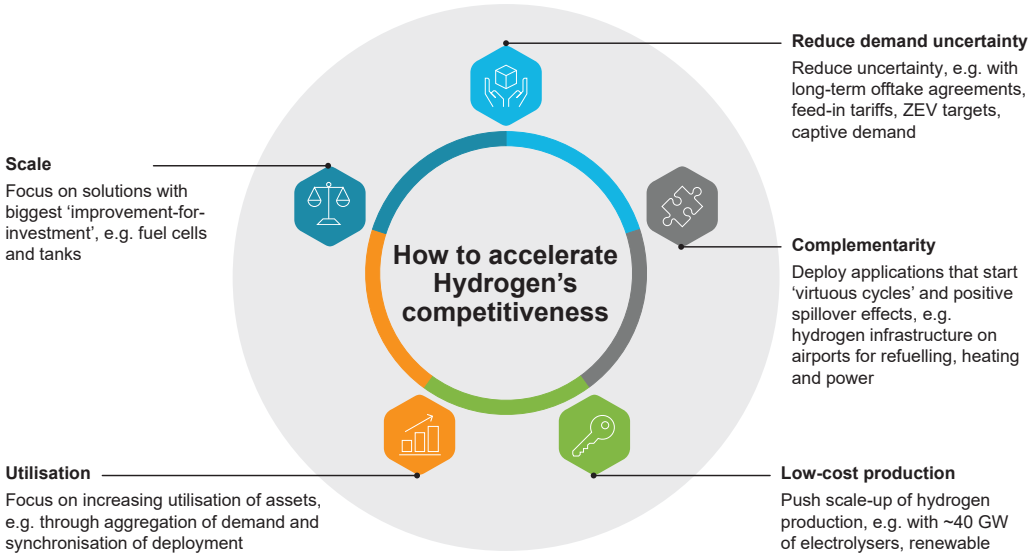
Governments need to support the above-mentioned investment and deployment across the board with policies that begin to level the playing field for low-carbon and conventional technologies. These may include all or some of the following:

- **National strategies.** Governments have to play a role in setting national targets, as they have done already through 18 hydrogen roadmaps developed across the globe. These roadmaps provide strong objectives for critical stakeholders to converge around.
- **Coordination.** Governments are well positioned as neutral conveners of industry stakeholders around potential local investment opportunities. This cost perspective provides some early indications of potentially important supply chain investments. Governments can play a role to convene investors around such opportunities.
- **Regulation.** Governments can help remove barriers that may exist to invest in the hydrogen economy today – for instance, by facilitating the process to obtain permits for new refuelling stations.
- **Standardisation.** Governments can also support industry to coordinate national and international standards; for example, around pressure levels and safety.
- **Infrastructure.** Governments can decide to support investments in deployment of new infrastructure, such as refuelling networks and re-use, where relevant, of existing natural gas grids. Such signals (along with corresponding moves on demand and supply) would be a strong motivation for industries to roll out technologies.
- **Incentives.** Finally, governments could decide to apply incentives such as tax breaks, subsidies or penalties on conventional alternatives to encourage (or even mandate) the initial acceleration of hydrogen. To represent these various incentives in our modelling, we include an implicit carbon cost – achievable by enacting a variety of policies – of USD 50 per ton of CO_2e by 2030, slowly increasing from today. More may be required if we want to reach a net-zero carbon economy by 2050.

Need for market creation

Even with the right enabling investments and policy support, the choices made at critical inflection points along the hydrogen industry's development will serve to either nurture or suppress its growth. We have identified five levers for stakeholders that can lead to major step changes in creating a market: reducing demand uncertainty, scaling applications with the biggest cost improvement per dollar invested, deploying complementary solutions to spark virtuous cycles, designing distribution networks to maximise utilisation and scaling up production to drive down supply costs. Exhibit 37 illustrates these levers.

Exhibit 37 | Five levers for stakeholders to create a market



Reduce demand uncertainty to attract investment

Investors typically seek some degree of certainty that demand exists to make them willing to fund new hydrogen projects. Industry and regulators have a number of options available, based on lessons learned from renewables, to minimise or mitigate market, regulatory, and technology risks. These fall into one of two categories: private-private and private-public arrangements. On the former, long-term offtake agreements have long been an investment vehicle of choice for renewables players. In addition to securing demand for renewables, offtake agreements have provided a hedge on energy prices for the offtaker while advancing energy transition and carbon abatement goals. Of the private-public variety, feed-in tariffs provide guaranteed payments from governments to private operators (e.g. industry or residential) in exchange for renewable energy supplied to the grid. They remove risks for producers to develop energy from renewable sources, reducing external costs and increasing security of energy supply. Similar arrangements could be imagined in hydrogen production and distribution, with pre-arranged offtake agreements and/or feed-in tariffs.

Another example to reduce demand uncertainty is facilitating the shift to hydrogen for end-to-end fleet logistics solutions that serve captive, recurring demand. For example, an end-to-end hydrogen fleet solution – as we see demonstrated in Switzerland, where it is underpinned by specific road fuel regulation – reduces demand uncertainty because it ensures players carry only the risks they can manage (as is also the case with feed-in tariffs).

Scale applications with the biggest cost improvement for investment

Critical tipping points – after which, costs fall sharply – appear throughout our analyses. Certain hydrogen applications have tipping points whereby a small volume increase can drastically reduce costs due to initially steep manufacturing learning rates. This is particularly true for fuel cells and tanks for vehicles. For example, scaling fuel cell vehicle production from 10,000 to 200,000 units can reduce unit costs by as much as 45 per cent, irrespective of any major technological breakthroughs, and can impact multiple end-use cases. Triggering these tipping points requires investment; for instance, in the first fuel cell car manufacturing plants as discussed above.

Deploy complementary solutions to spark virtuous cycles

Certain solutions create positive spill-over effects. The development of certain hydrogen solutions can create a virtuous cycle that makes other hydrogen applications viable. For example, leveraging hydrogen infrastructure around airports for on-site refuelling of buses, airport heating, local industry feedstock and, potentially in the future, aircraft refuelling will reduce the costs of each individual application.

Design distribution networks to maximise utilisation

For many hydrogen applications, network presence drives competitiveness. Stakeholders can make decisive moves to invest in solutions that are designed to reach high levels of utilisation quickly. For example, hydrogen boilers make the most sense as a heating solution where gas pipeline infrastructure already exists. Realising the potential first requires the grid operator – with support from regulators – to choose to decarbonise the gas grid versus continuing as is or shutting it down entirely. But once the choice is made, even factoring in the investment needed to retrofit the network and upgrade consumer appliances, hydrogen can still emerge as the most competitive solution.

Similar binary distribution choices exist for other applications, including hydrogen refuelling stations. If players build networks of larger stations to serve captive fleets, e.g. trucks, buses, and taxis, they can more quickly reach sufficient utilisation than if they focused on smaller stations serving the broader public. Networks serving the broader public should reach a minimum threshold scale to adequately serve customer needs, and therefore improve utilisation through volume. In the early ramp-up phase, specific demand guarantees can enable the development.

Scale up production to drive down supply cost

The cost of hydrogen production is instrumental for overall competitiveness of all hydrogen solutions. Unless we bring down the supply costs, all other business cases fail. Stakeholders can accelerate the hydrogen's cost reduction in a variety of way:

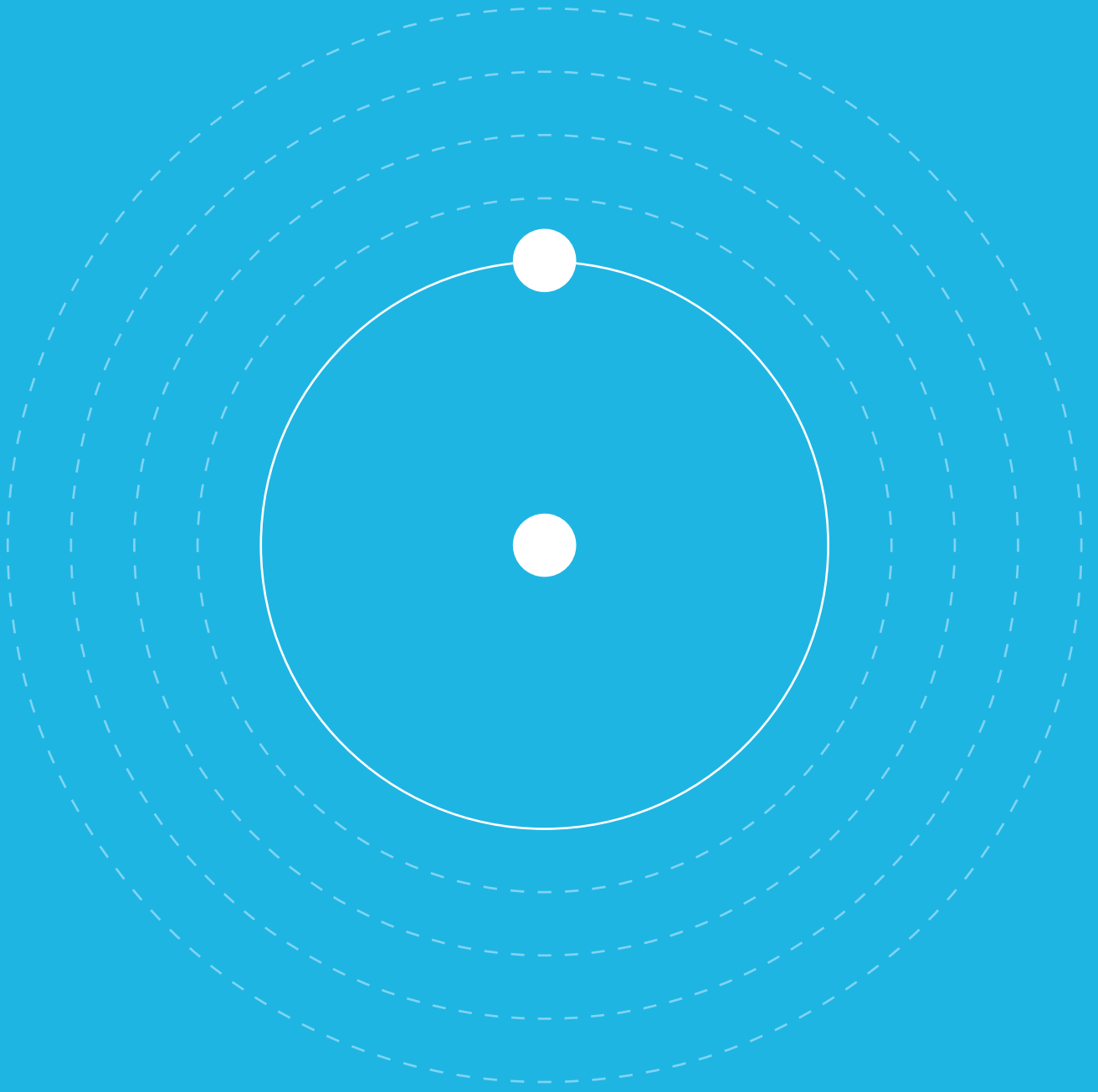
- **Renewable hydrogen.** The cost of renewable hydrogen from electrolysis consists of two components: the cost of renewables, specifically solar and wind, and the cost of electrolysis. Renewables are likely to continue to get progressively cheaper and more widely available given the current policy landscape. However, electrolysis cost reduction requires a concerted push to increase in electrolyser capacity deployed, with options for each of three types of hydrogen: we estimate that scaling up to 70 GW deployed would tip renewable hydrogen production to break even with grey. In fact, installing only roughly 40 GW of electrolysers could make renewable hydrogen competitive with grey in some regions. An initial regulatory push to incentivise production in countries with favourable renewables conditions could have a significant impact on lowering costs.
- **Reforming plus CCS.** Low-carbon hydrogen from reforming plus CCS can be relatively cheap in specific regional contexts – the abatement cost of switching from grey to low-carbon hydrogen from reforming plus CCS is relatively small – and would have a big impact on the viability of other applications further down the supply chain. However, producing low-carbon hydrogen from reforming plus CCS will require decision-makers to commit to large-scale projects, which will need regulatory support.
- **Grey hydrogen.** Most applications break even sooner when supplied by grey hydrogen. Although it is not a low-carbon solution, it can still be cleaner than the conventional alternative. Allowing it in cases where it is most cheaply and easily available, e.g. as a by-product, may make hydrogen applications financially viable much sooner. If no carbon reduction is achieved initially, this can be a first step to reduce the scale-up cost, and subsequently switch to low-carbon or renewable hydrogen along a clear and defined roadmap.

Conclusion

Hydrogen is a viable solution to the global decarbonisation challenge. As we have demonstrated through our analyses, the path to increasing cost competitiveness for hydrogen is clear for many applications. In some use cases, hydrogen can already outcompete other low-carbon and conventional alternatives.

The benefits of scaling up the hydrogen economy extend beyond its head-to-head cost competitiveness. Hydrogen can support governments' energy security goals, and its relative abundance creates opportunities for new players to emerge in energy supply and for new job creation to stimulate the global economy. Hydrogen remains the only viable, scalable option to decarbonise industry and other segments that have struggled to minimize their environmental impact. In addition, it can significantly advance goals around building a circular economy given the strong recyclability of the materials consumed along the entire value chain.

The time to act is now. There are many paths to realising hydrogen's full potential in the global energy transition, and nearly all of these options are worth pursuing immediately.



Glossary

ATAG	Air transportation action group
ATR	Autothermal reforming
BECCS	Bioenergy with carbon capture and storage
BEV	Battery electric vehicle
BOF	Blast oxygen furnace
BTX	Benzene, toluene, xylene
CHP	Combined heating and power
CCGT	Combined cycle gas turbine
CCP	Combined cooling and power
CCS	Carbon capture and storage
CCU	Carbon capture and utilization
CCUS	Carbon capture storage or utilisation
DoE	Department of Energy
DRI	Direct reduced iron
EAF	Electric arc furnace
EIA	Energy Information Administration (US)
EU	European Union
FC	Fuel cell (hydrogen)
FCEV	Fuel cell electric vehicle, including light- and heavy-duty vehicles, and material-handling vehicles
GHG	Greenhouse gas
HDV	Heavy-duty vehicle
HVO	Hydrotreated vegetable oil (type of biofuel)
ICE	Internal combustion engine
LDV	Light-duty vehicle

LPG	Liquified petroleum gas
MHE	Material-handling equipment
MMBTu	Million British thermal units (unit of energy, 1 MMBTU = 1.06 GJ)
NO_x	Nitrogen oxides (type of tailpipe emission from ICE vehicles)
NG	Natural gas
PEM	Polymer electrolyte membrane
R&D	Research and development
RE	Renewable energy
RNG	Renewable natural gas
SMR	Steam methane reforming
SOx	Sulfur oxides (type of tailpipe emission from ICE vehicles)
SUV	Sport utility vehicle
TCO	Total cost of ownership
T&D	Transmission and distribution
TW/GW/MW/kW	Terawatt, gigawatt, megawatt, kilowatt (unit of power, 1 Watt = 1 J per s)
TWh/MWh/kWh	Terawatt hour, megawatt hour, kilowatt hour (unit of energy, 1 Watt-hour = 3600 J)
ZEV	Zero-emissions vehicle

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