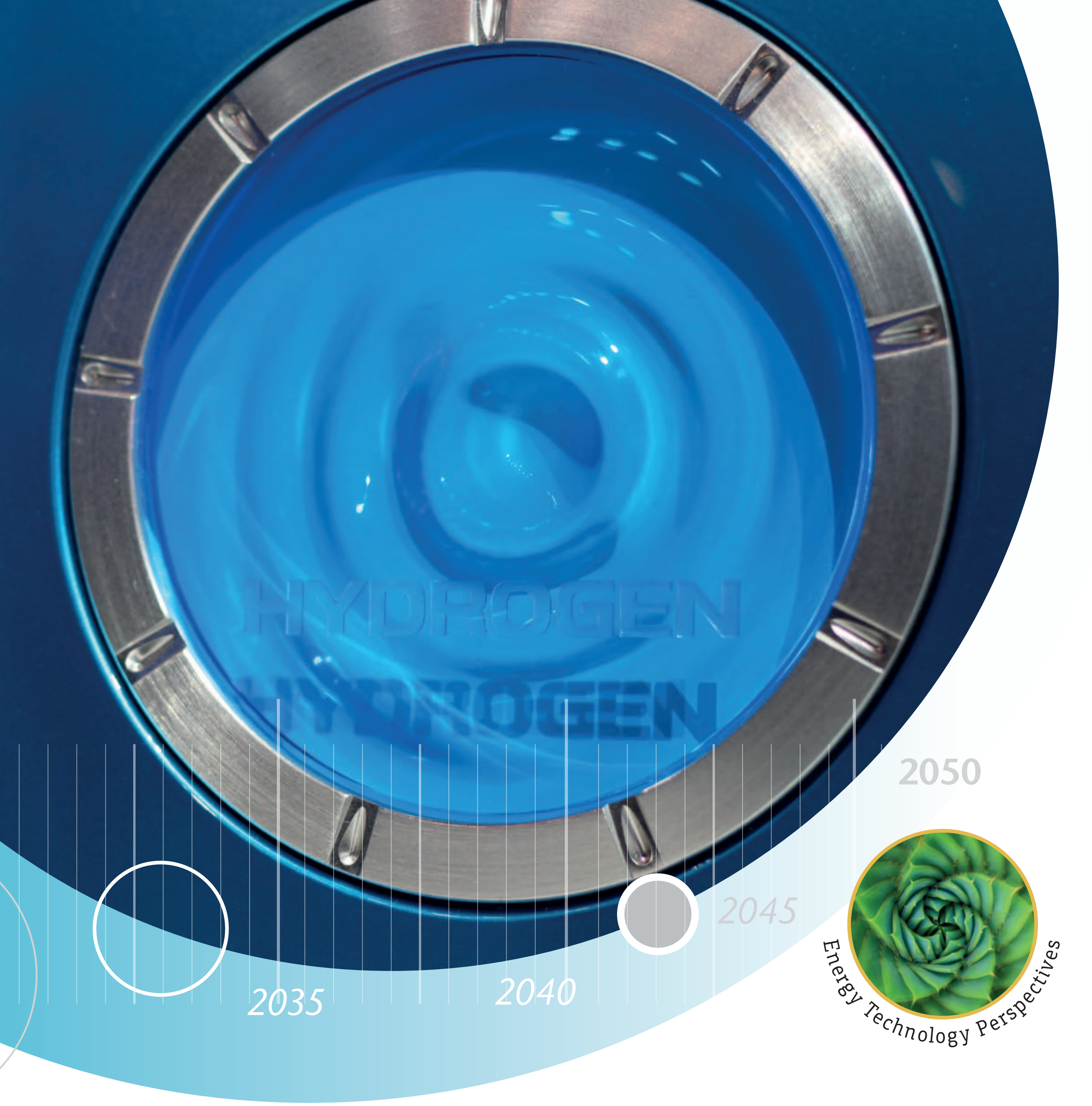


# Technology Roadmap

## Hydrogen and Fuel Cells

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The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its primary mandate was – and is – two-fold: to promote energy security amongst its member countries through collective response to physical disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy for its 29 member countries and beyond. The IEA carries out a comprehensive programme of energy co-operation among its member countries, each of which is obliged to hold oil stocks equivalent to 90 days of its net imports. The Agency's aims include the following objectives:

- Secure member countries' access to reliable and ample supplies of all forms of energy; in particular, through maintaining effective emergency response capabilities in case of oil supply disruptions.
- Promote sustainable energy policies that spur economic growth and environmental protection in a global context – particularly in terms of reducing greenhouse-gas emissions that contribute to climate change.
- Improve transparency of international markets through collection and analysis of energy data.
- Support global collaboration on energy technology to secure future energy supplies and mitigate their environmental impact, including through improved energy efficiency and development and deployment of low-carbon technologies.
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# Foreword

Current trends in energy supply and use are patently unsustainable – economically, environmentally and socially. Without decisive action, energy-related emissions of carbon dioxide ($CO_2$) will more than double by 2050 and increased fossil energy demand will heighten concerns over the security of supplies. We can and must change our current path. However, this will take an energy revolution and low-carbon energy technologies will have a crucial role to play. Energy efficiency, sources of renewable energy, carbon capture and storage (CCS), nuclear power and new transport technologies will all require widespread deployment if we are to achieve reductions in greenhouse gas (GHG) emissions. Every major country and sector of the economy must be involved. The task is urgent if we are to make sure that investment decisions taken now do not saddle us with sub-optimal technologies in the long term.

Awareness is growing of the need to turn political statements and analytical work into concrete action. To drive this forward, in 2008 the G8 requested the International Energy Agency (IEA) to lead the development of a series of roadmaps for some of the most important technologies. By identifying the steps needed to accelerate the implementation of radical technology changes, these roadmaps will enable governments, industry and financial partners to make the right choices. This will, in turn, help societies make the right decisions.

Hydrogen and fuel cell technologies, once they are more developed can support climate change and energy security goals in several sectors of the energy system, such as the transport, industry, buidings and the power sector. Hydrogen can connect different energy sectors and energy transmission and distribution (T&D) networks, and thus increase the operational flexibility of future low-carbon energy systems. It can help to: 1) achieve very low-carbon individual motorised transport; 2) integrate very high shares of variable renewable energy (VRE) into the energy system; 3) contribute to the decarbonisation of the industry and the buildings sector.

Although the GHG mitigation potential of hydrogen technologies is promising, important obstacles for widespread deployment of hydrogen and fuel cell technologies need to be overcome. These barriers are mainly related to current costs of fuel cells and electrolysers, the development of a hydrogen T&D and retail network, as well as the cost efficient generation of hydrogen with a low-carbon footprint.

Most hydrogen and fuel cell technologies are still in the early stages of commercialisation and currently struggle to compete with alternative technologies, including other low-carbon options, due to high costs. Additional attention will be required before their potential can be fully realised. Governments can help accelerate the development and deployment of hydrogen and fuel cell technologies by ensuring continued research, development and demonstration (RD&D) funding for hydrogen generation and conversion technologies, such as electrolysers and fuel cells. This will facilitate early commercialisation of fuel cell electric vehicles and support demonstration projects for VRE integration using hydrogen-based energy storage applications. Overcoming risks related to investment in infrastructure hinges upon close collaboration among many stakeholders, such as the oil and gas industry, utilities and power grid providers, car manufacturers, and local, regional and national authorities.

This publication is produced under my authority as Executive Director of the IEA.

***Maria van der Hoeven***
*Executive Director*
*International Energy Agency*

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# Key findings

## Cross-cutting opportunities offered by hydrogen and fuel cells

- Hydrogen is a flexible energy carrier that can be produced from any regionally prevalent primary energy source. Moreover, it can be effectively transformed into any form of energy for diverse end-use applications. Hydrogen is particularly well suited for use in fuel cells that efficiently use hydrogen to generate electricity.

- Hydrogen with a low-carbon footprint has the potential to facilitate significant reductions in energy-related $CO_2$ emissions and to contribute to limiting global temperature rise to 2°C, as outlined in the high hydrogen variant (2DS high $H_2$) of the IEA *Energy Technology Perspectives* (*ETP*) 2°C Scenario (2DS). In addition, hydrogen use can lower local air pollutants and noise emissions compared to direct fossil fuel combustion. By enabling continued use of fossil fuel resources for end-use applications under a 2DS, hydrogen production in combination with CCS can provide energy security benefits and help maintain a diversified fuel mix.

- As an energy carrier, hydrogen can enable new linkages between energy supply and demand, in both a centralised or decentralised manner, potentially enhancing overall energy system flexibility. By connecting different energy transmission and distribution (T&D) networks, sources of low-carbon energy can be connected to end-use applications that are challenging to decarbonise, including transport, industry and buildings. In remote areas with little access to the power grid, these connections can expand off-grid access to energy services while minimising emissions.

## Energy storage and utilisation in transport, industry and buildings

- Hydrogen is particularly useful as an energy carrier, because it allows low-carbon energy to be stored. Small quantities of hydrogen with low-carbon footprint can be stored under restricted space and weight requirements to enable long-distance, low-carbon driving using fuel cell electric vehicles (FCEVs). Large quantities of hydrogen can be stored over long periods of time, facilitating the integration of high shares of variable renewable energy (VRE) into the energy system for power and heat. Hydrogen-based systems such as power-to-fuel, power-to-power or power-to-gas can be employed to make use of VRE that would otherwise be curtailed at times when supply outstrips demand.

- FCEVs can provide the mobility service of today's conventional cars at potentially very low-carbon emissions. Deploying a 25% share of FCEVs in road transport by 2050 can contribute up to 10% of all cumulative transport-related carbon emission reductions necessary to move from an *ETP* 6°C Scenario (6DS) to a 2DS, depending on the region. Assuming a fast ramp-up of FCEV sales, a self-sustaining market could be achieved within 15 to 20 years after the introduction of the first 10 000 FCEVs.

- While the potential environmental and energy security benefits of hydrogen and fuel cells in end-use applications are promising, the development of hydrogen generation, T&D and retail infrastructure is challenging. For example, the risks associated with market uptake of FCEVs have been a significant barrier to infrastructure investment. For each of the assumed 150 million FCEVs sold between now and 2050, around USD 900 to USD 1 900 will need to be spent on hydrogen infrastructure development, depending on the region.[1]

1. Unless otherwise stated, all monetary values are in 2013 USD.

# Key actions in the next ten years

## Cross-cutting opportunities offered by hydrogen and fuel cells

- Encourage fuel efficiency and low greenhouse gas emission technologies across all energy sectors through market driven, technology- and fuel-neutral policies. A stable policy and regulatory framework – including for example carbon pricing, feed in tariffs, fuel economy standards, renewable fuel standards or zero-emission vehicle mandates – is important for raising market certainty for investors and entrepreneurs.
- Stimulate investment and early market deployment of hydrogen and fuel cell technologies and their infrastructure through effective policy support to bring down costs. National and regional priorities should determine the value chains and the market barriers to be targeted.
- Continue to strengthen and harmonise international codes and standards necessary for safe and reliable handling and metering of hydrogen in end-use applications.
- Keep up supporting technology progress and innovation by unlocking public and private funds for RD&D for key hydrogen technologies, such as fuel cells and electrolysers. Enhance the focus on cross-cutting research areas, such as materials, that could play a transformative role in improving performance. Where possible, promote projects with international cooperation to maximise the efficiency of funding.
- Improve understanding of regionally specific interactions between different energy sectors through integrated modelling approaches to quantify benefits of energy system integration.
- Where regionally relevant, accelerate activities directed at developing the capture and storage of $CO_2$ from fossil-derived hydrogen production into mature business activities.

## Energy storage and utilisation in transport, industry and buildings

- Prove on-road practicality and economics across the supply chain of FCEVs by putting the first tens of thousands of vehicles on the road, along with hydrogen generation, T&D and refuelling infrastructure, including at least 500 to 1 000 stations in suitable regions around the world, and cross-border projects. Build upon deployment programmes in Europe, Japan, Korea and California as well as the use of captive fleets.
- Engage international stakeholders from relevant industries as well as regional, national and local authorities in developing risk-mitigation strategies, including the development of financial instruments and innovative business models that de-risk hydrogen T&D and retail infrastructure development for FCEV market introduction.
- Increase the number of hydrogen-based energy storage systems suitable for integrating VRE and collect and analyse performance data under real-life conditions.
- Establish regulatory frameworks that remove barriers to grid access for electricity storage systems including power-to-fuel and power-to-gas applications. Where regionally relevant, establish a regulatory framework for the blending of hydrogen into the natural gas grid.
- Increase data on resource availability and costs for hydrogen generation at national and regional levels. Analyse the potential future availability of curtailed electricity for hydrogen production as a function of VRE integration, other power system flexibility options and competing demands for any surplus renewable electricity.
- Address potential market barriers where opportunities exist for the use of low-carbon hydrogen in industry (e.g. in refineries).
- Extend information campaigns and educational programs to increase awareness-raising.

# Introduction

Hydrogen is a flexible energy carrier with potential applications across all energy sectors. It is one of only a few potential near-zero emission energy carriers, alongside electricity and advanced biofuels. Nonetheless, it is important to note that hydrogen is an energy carrier and not an energy source: although hydrogen as a molecular component is abundant in nature, energy needs to be used to generate pure hydrogen. The hydrogen can then be used as a fuel for end-use conversion processes, for example using fuel cells to produce power. As is the case for electricity generation, hydrogen production incurs a cost and suffers from thermodynamic losses.

Hydrogen can be produced from various primary or secondary energy sources, depending on regional availability. Primary energy sources useful for hydrogen production comprise renewable sources, such as biomass, and also fossil fuels, such as natural gas and coal. Electricity can also be used for hydrogen generation using electrolysers, which are a pivotal technology for enabling the splitting of water into its components hydrogen and oxygen.

Hydrogen itself contains no carbon – if used in a fuel cell or burned in a heat engine, water or water vapour is the only exhaust. Nevertheless, hydrogen can have a very significant carbon footprint. Its lifecycle carbon emissions are determined by the primary energy source and the process used for hydrogen production, and need to be taken into account when quantifying climate benefits.

While not ignoring the implications of hydrogen generation pathways, this roadmap focuses primarily on the demand side of the energy system. There, hydrogen could play an important role in future road transport, as FCEVs can be a low-carbon alternative to conventional passenger cars and trucks. In buildings, micro co-generation units could increase energy efficiency.[2] In the longer run, industrial processes in the refining, steel and chemical industries could be substantially decarbonised through the use of hydrogen with a low-carbon footprint. In many, but not all of these applications, fuel cells are an important technology for converting hydrogen to power and heat. Fuel cells are intimately but not exclusively linked to hydrogen. They can also be used with other fuels such as natural gas or even liquid hydrocarbons, thus helping their early adoption.

Producing hydrogen from electricity and storing it in gaseous or liquefied form could be an option for increasing the flexibility of the energy system, allowing for the integration of high shares of VRE. Hydrogen can enable "power-to-x" trajectories – its capability of being converted to various forms of final energy, such as power, heat and transport fuels, can be used to join subsystems of the energy system that historically had no, limited or only one-way linkages.

This is what makes this roadmap especially challenging. Many of the technology components are less mature than technologies featured in other IEA Technology Roadmaps, adding greater uncertainty to technological and economic parameters. A proper inter-sectoral view of the energy system also requires integrated modelling, which becomes highly complex if the target is significant temporal and spatial detail. For this roadmap the IEA *ETP* toolbox has been enhanced to account for some of the synergies that emerge when high shares of VRE integration on the energy supply side are combined with demand for hydrogen as a fuel.

## Rationale for hydrogen and fuel cell technologies

As outlined in the 2015 edition of *ETP* (IEA, 2015), contributions to reducing GHG emissions from the energy supply sector and all energy demand sectors will be needed if dangerous climate change is to be prevented.

On the energy supply side, the power sector needs to be deeply decarbonised if an ambitious emission reduction scenario to limit global warming to 2°C above pre-industrial levels is to be achieved. On a global scale, annual emissions need to be reduced by 85% by 2050 compared to today's levels, which is achieved in the 2DS to a large extent by an increase of renewable power to about 63% of generated electricity by 2050. This high level of renewable energy integration, which following the 2DS will need to be exceeded in certain regions such as the European Union, necessitates a deep structural change in the way we operate power systems.

Discussion of low-carbon energy systems frequently centres on issues such as flexibility and system integration. Today's perception of flexibility is mostly related to energy supply. In fact, it is closely linked to energy storage. Fossil resources store immense amounts of energy. They can be used

2. Co-generation refers to the combined production of heat and power.

when and where necessary, their high energy density (either in gaseous, liquid or solid form) allowing them to be efficiently transported over long distances. This inherently provides the energy system with a lot of flexibility. In a low-carbon energy system based on high shares of VRE, this temporal and spatial flexibility to modulate energy supply according to demand is limited.

Electricity from VRE carries the temporal and spatial imprint of its resource: sunlight, wind, tidal and wave patterns. Their patterns are not necessarily aligned with variations in demand – with regard both to location and time of supply. This causes periods of supply surplus and deficit, which will differ from one place to another. Moreover, fluctuating output as a result of weather variability can lead to rapid swings in supply. This is a challenge, because the electricity grid requires electricity supply and demand to be in balance instantaneously and at all times. A suite of options is available to overcome the space and time mismatch of variable electricity supply and demand. Grid infrastructure, flexible generation, demand-side response and energy storage can all be used in this way, but should be used according to their relative economic performance.

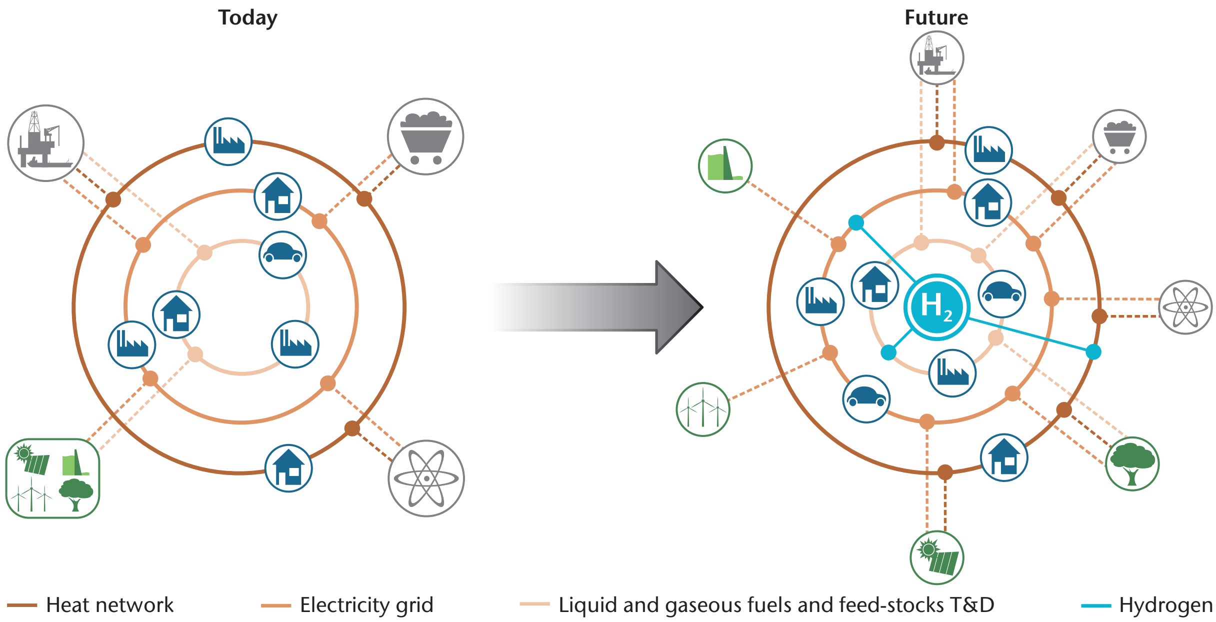
Hydrogen generated from electricity and water can be stored in large quantities over long periods and re-transformed to electricity (power-to-power) – although at an efficiency cost of more than 70% of the input electricity. It can be mixed into the natural gas grid or converted to synthetic methane power-to-gas) or sold as fuel for FCEVs to the transport sector (power-to-fuel). Hydrogen may thus open up entirely new ways to integrate renewable electricity in the energy system and compensate in part for the loss of flexibility resulting from reduced use of fossil fuels.

Decoupling energy use and carbon emissions on the energy supply side needs to be complemented by measures within energy demand sectors, notably transport, buildings and industry. The main mitigation options are technological improvement (either through efficiency improvements of conventional technologies or the deployment of new technologies) and behavioural change to reduce energy use, as well as switching to low-carbon fuels.

Road transport is a large carbon emitter, accounting for about three-quarters of all transport emissions. Apart from avoiding road transport demand and shifting it to more efficient transport modes, such as passenger and freight rail, substantially decarbonising the road transport sector can be achieved by: 1) increasing the share of direct use of low-carbon electricity via battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs); 2) significantly raising the share of sustainable low-carbon biofuels in combination with high-efficiency hybridised internal combustion engine (ICE) vehicles and PHEVs; 3) the use of FCEVs fuelled by low-carbon footprint hydrogen. All three options can substantially contribute to reducing emissions, but hinge on overcoming different barriers. Energy storage is again pivotal – the higher the demand for autonomy, the greater the need for energy to be stored on board.

BEVs can draw upon existing electricity generation and T&D infrastructure, and rely on the fact that their carbon impact would be reduced by the decarbonisation already taking place in the power sector. Still, batteries face a serious trade-off between energy capacity and weight, and range anxiety and recharging time are major concerns for consumers. In the case of biofuels, production raises doubts with respect to sustainability and displacement of food production, particularly as considerable amounts of biofuels will be necessary to decarbonise long-haul road freight, aviation and shipping. By contrast, FCEVs could provide transport utility comparable to today's vehicles while, at the same time, meeting climate and energy security targets. Here, the challenge is to build up an entirely new hydrogen generation, T&D and retail network. The main barrier to overcome is the risk related to committing investment in large-scale FCEV production on the one hand, and hydrogen infrastructure roll-out on the other, particularly against a background of high uncertainty with respect to FCEV market uptake. Therefore, a better understanding of consumer preferences with regard to vehicle range, refuelling and recharging infrastructure provision as well as safety concerns is key to improve projections of the market potential of low or zero-emission vehicles.

## Figure 1: Energy system today and in the future




***KEY POINT: Hydrogen can link different energy sectors and energy T&D networks and thus increase the operational flexibility of future low-carbon energy systems.***

Substituting fossil-derived hydrogen with low-carbon footprint hydrogen in industrial applications also offers significant potential for carbon emission mitigation. Globally, the refining, chemical and industrial gas industries use approximately 7.2 exajoules (EJ) of hydrogen per year (Suresh et al., 2013). Around 48% of this is currently produced from natural gas, using steam methane reforming (SMR) without CCS, 30% arises as a fraction of petroleum during the refining process, 18% is produced from coal, and the balance (4%) is electrolytic hydrogen (Decourt et al., 2014). Altogether, the used hydrogen resulted in annual emissions of approximately 500 megatonnes (Mt) $CO_2$. In general, depending on region-specific natural gas prices, hydrogen produced via large-scale SMR processes is typically available at relatively low costs. This together with anticipated T&D costs will set the benchmark against which alternative, low-carbon hydrogen production pathways need to be measured.

In the steel industry, more efficiently integrating the hydrogen generated in classic blast furnaces in the steelmaking process could deliver significant carbon emission reductions today. Processes to directly reduce iron ore (DRI) in the presence of hydrogen could unlock an important mitigation potential, especially if low-carbon footprint hydrogen was available at competitive cost.

A schematic representation of today's energy system and a potential low-carbon energy system of the future are shown in Figure 1. The key difference lies in the different energy vectors used to supply transport, buildings and industry, and in particular the T&D of electricity, heat, and liquid as well as gaseous fuels via different energy networks. Today's energy system is heavily dependent on fossil fuels and, apart from co-generation, few connections exist between the different T&D systems. In a future system, hydrogen could play a pivotal role by connecting different layers of infrastructure in a low-carbon energy system.

The use of hydrogen as an energy carrier is closely linked to the deployment of fuel cells and electrolysers. Fuel cells are the key technology to efficiently convert hydrogen into electricity to propel FCEVs, or for using it in other end-use applications in buildings or industry (eventually exploiting the waste heat for heating purposes). In addition, fuel cells can also convert a range of other hydrocarbon fuels, such as natural gas or methanol, and the immediate use of such fuels for which there is existing infrastructure in fuel cells could be an important step to help reduce technology costs that remain high today.

Electrolyser technology is pivotal to establish the new links between the power sector and transport, buildings and industry. They allow the conversion of renewable electricity into hydrogen, a zero carbon chemical fuel and feedstock, by splitting water into hydrogen and oxygen.

## Purpose, process and structure of the roadmap

The purpose of this roadmap is to lay out hydrogen's potential in different energy sectors, and also its limitations. The roadmap aims to:

- Provide an extensive discussion of the nature, function and cost of key hydrogen technologies.
- Identify applications where using hydrogen can offer the maximum added value.
- Identify the most important actions required in the short and long term to successfully develop and deploy hydrogen technologies in support of global energy and climate goals.
- Increase understanding among a range of stakeholders of the potential offered by hydrogen technologies, particularly the synergies they offer existing energy systems.

This roadmap was developed with the support of a wide range of stakeholders, including members of industry, academia and government institutions. To facilitate collaboration, the IEA Hydrogen Technology Roadmap team hosted three regional expert workshops to examine region-specific opportunities for and barriers to hydrogen technology deployment (Table 1).

### Table 1: Workshops parallel to the development of the Technology Roadmap on Hydrogen and Fuel Cells

| *Date* | *Workshop focus* |
| --- | --- |
| 9-10 July 2013 | Kick-off meeting and Europe-focused expert workshop: scope, technology, market and policy discussion |
| 28-29 January 2014 | North America-focused expert workshop: hydrogen generation pathways, technology, market and policy discussion |
| 26-27 June 2014 | Asia-focused expert workshop: technology, market and policy discussion |

Due to the roadmap's broad scope, covering both energy supply and several energy demand sectors, the detailed results provided in the "Vision" section focus on selected regions, including EU 4 (France, Germany, Italy and the United Kingdom), Japan and the United States.

## Roadmap scope

The following applications are the focus of this roadmap:

- hydrogen-based systems in energy demand sectors – FCEVs in transport, fuel cell micro co-generation in the residential sector and selected applications in the refining, steel and chemical industries
- hydrogen in the energy supply sector – VRE integration and energy storage, comprising power-to-power, power-to-gas and power-to-fuel
- hydrogen infrastructure – T&D, storage and retail technologies
- key hydrogen generation and conversion technologies – electrolysers and fuel cells.

# Technology status today

In 2013, global hydrogen usage amounted to a total of 7.2 EJ (Suresh et al., 2013). To date this hydrogen has not been used as an energy carrier, i.e. it is not converted into electricity, mechanical energy or heat to be used for energy service. Hydrogen is almost entirely used as feedstock within the refining and chemical industries to convert raw materials into chemical or refinery products.

The generation of hydrogen from fossil resources, its transmission, distribution and use within industry and the refining sector are based on mature technologies and applied on a large scale, and are not the main focus of this roadmap. However, these mature technologies will play an important role in a transition to low-carbon hydrogen.

The use of hydrogen as an energy carrier is beginning to emerge – although the first FCEVs were developed in the 1960s, it is only in the last ten years that the technology has developed to an extent that certain car manufacturers are announcing the launch of FCEVs. Toyota launched its Mirai ("Future") model in Japan in 2014, Hyundai is planning to begin the sale of FCEVs in the near future (the Hyundai Tucson FCEV has been available for lease since summer 2014), and Honda announced plans to launch its next generation FCEV in 2016. Although predicted production numbers are a small fraction of conventional passenger car sales, or even those of electric vehicles, they show the increased interest of car manufactures in this technology.[3]

A similar trend can be observed in the field of energy storage applications. Increasing numbers of hydrogen-based large-scale energy storage demonstration projects are being launched, planned or announced, with a remarkable concentration of activity in Germany, motivated by the attempt to explore benefits for the integration of VREs. Likewise, opportunities to store large amounts of hydrogen using chemical hydrides are being actively explored in Japan.

Japan certainly leads the field in the stationary application of fuel cell technology, with more than 120 000 "Ene-farm" domestic fuel cell micro co-generation systems already installed (NEDO, 2014).

In the following sections, technology status and opportunities are reviewed for hydrogen and fuel cell applications and individual technologies. FCEVs together with hydrogen T&D and retail infrastructure, hydrogen-based energy storage systems, hydrogen technologies in industry and fuel cells in buildings are considered in turn. This is followed by a more detailed discussion of some of the key technologies for generating, using and storing hydrogen.

## Hydrogen in transport

An overview of hydrogen systems in the transport sector and their techno-economic parameters is shown in Table 2. More detailed technical data on hydrogen technology components, such as fuel cells and electrolysers, are briefly discussed in the sections "Key hydrogen production technologies" and "Key hydrogen conversion technologies" as well as in the Roadmap Technology Annex.

Although other pathways to use hydrogen as a fuel in transport are feasible, e.g. via the use of synthetic methane in compressed natural gas (CNG) vehicles or through conversion to methanol, the current analysis focuses on FCEVs and the use of pure hydrogen.

3. In 2013 around 63 million passenger light-duty vehicles (PLDVs) were sold globally (OICA, 2014), while in 2014 around 300 000 BEVs and PHEVs were sold (EVI, 2015).

## Table 2: Current performance of hydrogen systems in the transport sector

| Application | Power or energy capacity | Energy efficiency* | Investment cost** | Lifetime | Maturity |
|---|---|---|---|---|---|
| Fuel cell vehicles | 80 - 120 kW | Tank-to-wheel efficiency 43-60% (HHV) | USD 60 000-100 000 | 150 000 km | Early market introduction |
| Hydrogen retail stations | 200 kg/day | ~80%, incl. compression to 70 MPa | USD 1.5 million-2.5 million | - | Early market introduction |
| Tube trailer (gaseous) for hydrogen delivery | Up to 1 000 kg | ~100% (without compression) | USD 1 000 000 (USD 1 000 per kg payload) | - | Mature |
| Liquid tankers for hydrogen delivery | Up to 4 000 kg | Boil-off stream: 0.3% loss per day | USD 750 000 | - | Mature |

* Unless otherwise stated, efficiencies are based on lower heating values (LHV).

** All power-specific investment costs refer to the energy output.

Notes: HHV = higher heating value; kg = kilogram; kW = kilowatt.

Sources: IEA data; Decourt et al. (2014), *Hydrogen-Based Energy Conversion, More than Storage: System Flexibility*; Elgowainy (2014), "Hydrogen infrastructure analysis in early markets of FCEVs", IEA Hydrogen Roadmap North America Workshop; ETSAP (2014), *Hydrogen Production and Distribution*; Iiyama et al. (2014), "FCEV Development at Nissan", ECS Transactions, Vol. 3, pp. 11-17; Nexant (2007), "Liquefaction and pipeline costs", Hydrogen Delivery Analysis Meeting, 8-9 May; NREL (2014), *Hydrogen Station Compression, Storage and Dispensing - Technical Status and Costs*; NREL (2012a), *National Fuel Cell Electric Vehicle Learning Demonstration Final Report*; US DOE (2010a), *Hydrogen Program 2010 Annual Progress Report - Innovative Hydrogen Liquefaction Cycle*; US DOE (2010b), *DOE Hydrogen Program 2010 Annual Progress Report - Technology Validation Sub-Program Overview*; Yang and Ogden (2007), "Determining the lowest-cost hydrogen delivery mode", *International Journal of Hydrogen Energy*, pp. 268-286.

### FCEVs

FCEVs are essentially electric vehicles using hydrogen stored in a pressurised tank and a fuel cell for on-board power generation. FCEVs are also hybrid cars, as braking energy is recuperated and stored in a battery. The electric power from the battery is used to reduce peak demand from the fuel cell during acceleration and to optimize its operational efficiency. Being both electric and hybrid vehicles, FCEVs benefit from technological advancement in both technologies, since they have a significant amount of parts such as batteries and power electronics in common (McKinsey and Co., 2011).

Today around 550 FCEVs (passenger cars and buses) are running in several demonstration projects across the world (Table 3). A small number of fuel cell heavy freight trucks (HFTs) are currently being used in a demonstration project at the port of Los Angeles, testing the usability of range extenders with electric trucks.

## Table 3: Existing FCEV fleet and targets announced by hydrogen initiatives

| Country or region | Running FCEVs | Planned FCEVs on the road | |
|---|---|---|---|
| | | 2015 | 2020 |
| Europe | 192 | 5 000 | ~350 000 |
| Japan | 102 | 1 000 | 100 000 |
| Korea | 100 | 5 000 | 50 000 |
| United States | 146 | ~300 | ~20 000 |

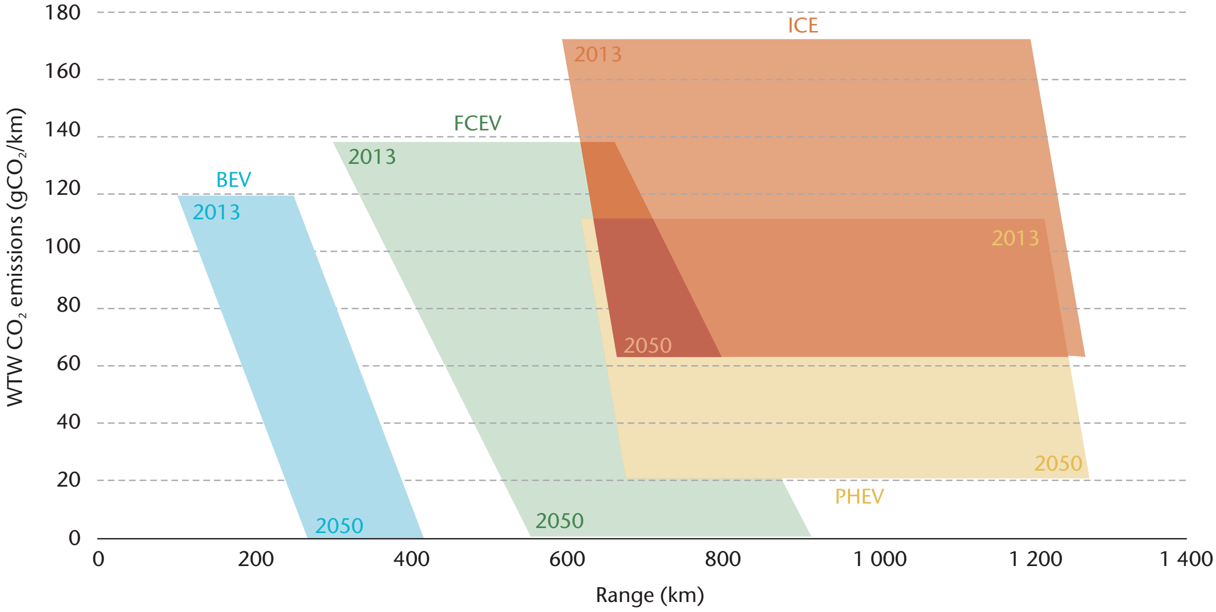
Sources: Weeda et al. (2014), *Towards a Comprehensive Hydrogen Infrastructure for Fuel Cell Electric Cars in View of EU GHG Reduction Targets*; personal contact with US Department of Energy; Japanese registration number from database of Japan Automobile Dealers Association (JADA, March, 2015).

To date, FCEVs are fuelled with gaseous hydrogen at pressures of 35 MPa to 70 Mpa. As 70 MPa tanks allow for much higher ranges at acceptable tank volumes, most recent demonstration vehicles are equipped with these.

Currently, on-road fuel economy is around 1 kg of hydrogen per 100 km travelled, and demonstration cars have ranges of around 500 km to 650 km. Since the driving performance of FCEVs is comparable to conventional cars and refuelling time is about the same, FCEVs can provide the mobility service of conventional cars at much lower carbon emissions, depending on the hydrogen generation pathway (Figure 2).

Vehicle costs remain high – FCEV prices announced to date have been set at around USD 60 000 (Toyota, 2015) during the early market introduction phase. Announced prices might rather reflect the

## Figure 2: Well-to-wheel (WTW) emissions vs. vehicle range for several technology options




Notes: $gCO_2$/km = grams carbon dioxide per kilometre; WTW = wheel-to-wheel; the upper range of BEV emissions takes into account today's average world power generation mix, the lower range is based on 100% renewable electricity; the upper range of FCEV emissions takes into account a. hydrogen production mix of 90% NG SMR and 10% grid electricity, the lower range is based on 100% renewable hydrogen; the lower range of PHEV emissions takes into account 65% electric driving; by 2050, a biofuel share of 30% is assumed for PHEVs and ICEs.

*KEY POINT: FCEVs can achieve a mobility service compared to today's conventional cars at potentially very low WTW carbon emissions.*

assumed customers' willingness to pay than the costs to produce the vehicles. Current FCEV models are targeted at high-income and technophile early movers living close to hydrogen refuelling infrastructure clusters, which are starting to develop in California, Germany, Japan and Korea.

The high cost of the fuel cell systems is driving total vehicle costs, and the current challenge lies in reducing fuel cell stack and balance of plant (BOP) costs while simultaneously increasing lifetime. While economies of scale have huge potential to drive down fuel cell costs, the cost of the high-pressure tank is largely determined by expensive composite materials, which are expected to fall much more slowly (Argonne National Laboratory - Nuclear Division, 2010). This is why the focus of recent R&D has been on accelerating cost reductions in composite materials for high-pressure tanks. To bring down the costs of the entire FCEV, manufacturers are currently focusing on "technology packaging", to finally be able to mount the fuel cell power train on the same chassis used for conventional cars.

To realise their full performance potential against conventional cars, FCEVs target the medium and upper size car segments. Initially, costly technologies are typically introduced in premium cars, but in the longer term more than three-quarters (vehicle class C and higher [IEA (2012)]) of the passenger light-duty vehicle (PLDV) market would be suitable for fuel cell technology.

Since FCEVs will target the same vehicle class like plug-in hybrids – medium and upper size class vehicles able to cover large distances – these might be the closest competing low-carbon technology. Compared to plug-in hybrids, FCEVs could enable very low-emission individual motorised transport. At high annual production rates and under optimistic assumptions with regard to fuel cell systems and hydrogen storage tanks, FCEVs have the potential to be less costly than plug-in hybrids. This is largely due to their lower complexity since they do not require two different drive-trains.

Fleet vehicles can play a significant role in the initial market introduction phase. Refuelling at a base location allows the necessary hydrogen refuelling infrastructure, and the associated costs, to be kept to a minimum. As a result of better utilisation of the refuelling equipment and higher annual mileages, economic viability of fleet FCEVs could be achieved earlier than for individually owned vehicles. The French HyWAY programme, for example, aims to de-risk the development of infrastructure for FCEVs by focusing on captive fleets.

Broad personal vehicle ownership of FCEVs may also hinge upon overcoming consumer concerns about passenger safety in collisions, ability of the general public to safely refuel, and safety in tunnels or enclosed parking spaces.

Heavy-duty vehicles such as trucks and buses can also be equipped with fuel-cell powertrains. Significant experience with fuel cell buses already exists (McKinsey and Co., 2012) and partly results from being able to draw upon the fleet vehicle advantage. Public transport subsidies are common and could ease the introduction of fuel cell technology in that field. Furthermore, co-benefits such as reduced air pollution can be an important argument for FCEV and particularly fuel-cell bus deployment, especially in heavily polluted and densely populated urban areas around the world.

Fuel cell trucks are one of only very limited options available to deeply decarbonise heavy-duty, long-haul road freight transport. Although competition with other low-carbon technologies is less pronounced in that segment, fuel cell long-haul HFTs will face difficulty competing with advanced conventional trucks. HFT diesel engines can already achieve high efficiencies (up to 40%) during constant highway cruising speeds. Fuel cell efficiencies decline with increasing power output, and using them in HFTs decreases the efficiency benefit compared to conventional technology. Furthermore, as HFTs require long-range autonomy, on-board storage of the necessary volumes of hydrogen becomes critical. Compared to conventional diesel technology, hydrogen stored at 70 MPa still needs four times more space to achieve the same range, even taking into account the higher efficiency of the fuel cell powertrain (IEA, 2012). The potential role of fuel cell technology in HFTs is thus more uncertain.

## Hydrogen T&D

Hydrogen refuelling stations can be supplied by one of two alternative technologies: hydrogen can be produced at the refuelling station using smaller-scale electrolysers or natural gas steam methane reformers, or can be transported from a centralised production plant. Each approach has its own advantages and trade-offs. While large-scale, centralised hydrogen production offers economies of scale to minimise the cost of hydrogen generation, the need to distribute the hydrogen results in higher T&D costs. Meanwhile, the opposite is true for decentralised hydrogen generation. While T&D costs are minimised, smaller-scale production adds costs at the hydrogen generation stage. Finding the optimal network configuration requires detailed analysis taking into account the full range of local factors, such as geographic distribution of resources for hydrogen production, existing hydrogen generation and T&D infrastructure, anticipated hydrogen demand at the retail station and distance between the place of hydrogen production and hydrogen demand. However, economies of scale realised in large centralised hydrogen generation facilities tend to potentially outweigh the additional costs of longer T&D distances.

A number of options are available for hydrogen T&D: gaseous truck transport; liquefied truck transport; and pumping gaseous hydrogen through pipelines (Table 4). A trade-off exists between fixed and variable costs: while gaseous truck delivery has the lowest investment cost, variable costs are high as a result of the lower transport capacity. The opposite is true for pipelines – fixed costs are driven by high investment costs. Once the pipeline is fully

## Table 4: Qualitative overview of hydrogen T&D technologies for hydrogen delivery in the transport sector

| | Capacity | Transport distance | Energy loss | Fixed costs | Variable costs | Deployment phase |
|---|---|---|---|---|---|---|
| Gaseous tube trailers | Low | Low | Low | Low | High | Near term |
| Liquefied truck trailers | Medium | High | High | Medium | Medium | Medium to long term |
| Hydrogen pipelines | High | High | Low | High | Low | Medium to long term |

utilised, the variable costs are low. The lowest-cost pathway depends on many factors, with hydrogen demand at the refuelling station and T&D distance being the most important.

### Hydrogen refuelling stations

Hydrogen refuelling stations are a critical element in the fuel supply chain for FCEVs, as providing a minimum network density is a prerequisite to attaining consumer interest. They can be exclusively for hydrogen or part of a multi-fuel station.

The set-up of a hydrogen station is largely determined by daily hydrogen demand, the form of hydrogen storage on board the vehicle (e.g. the pressure and the phase), and the way hydrogen is delivered to or produced at the station. Determining the optimal size of a station is a critical step. While very small stations with daily capacities of 50 kg to 100 kg of hydrogen might be necessary in the beginning (basically allowing for 10 to 20 refills a day), stations up to 2 000 kg per day will be needed in a mature market.

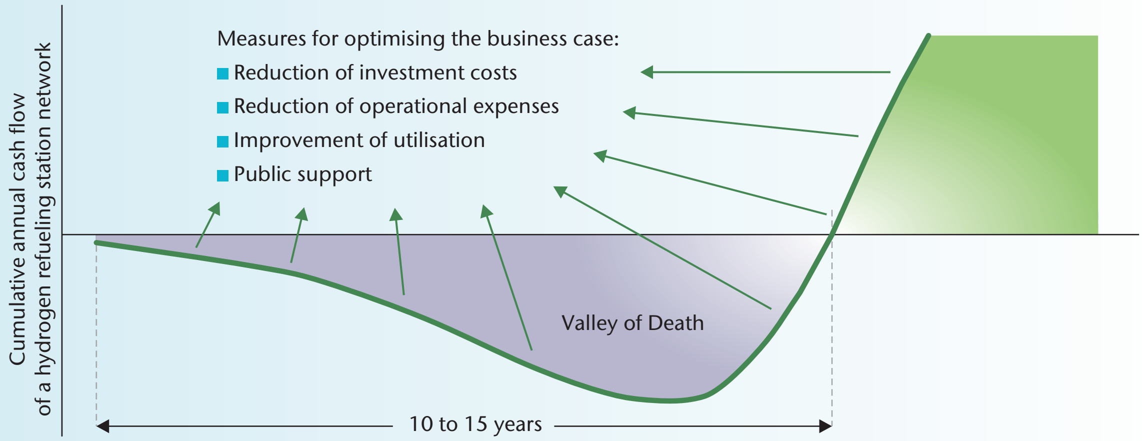
The link to hydrogen T&D technologies is obvious. While small stations could be based on gaseous trucking or on-site hydrogen production, liquefied trucking or the use of pipelines are the only options for hydrogen delivery to stations larger than 500 kg per day, if the hydrogen is not produced on-site. The set-up of the station hence implies a certain path dependency, which complicates investment decision-making, as multiple risks (mainly linked to the pace of FCEV market uptake and hydrogen demand) need to be taken into account (Box 1).

## Box 1: Risks associated with investment in hydrogen refuelling stations

The investment risk associated with the development of refuelling stations is mainly due to high capital and operational costs, and the under-utilisation of the facilities during FCEV market development, which can lead to a negative cumulative cash flow over 10 to 15 years (Figure 3).

This long "valley of death" can be minimised by reducing capital and operation costs and maximising asset utilisation. High capital costs are mainly linked to hydrogen compression and storage. The higher the pressure of hydrogen stored on board FCEVs, the more expensive are the compressors needed at the station – a 35 MPa refuelling station is about one third less costly than a 70 MPa station. The requirement for compression at the station can be minimised either by delivering the hydrogen at high pressure from the hydrogen generation plant, or by lowering the required pressure on board the FCEV. It would even be possible to provide hydrogen at several pressure levels, where only stations on long-distance corridors would provide the option to refuel at 70 MPa.

## Figure 3: Cumulative cash flow curve of hydrogen stations in the early market phase




*KEY POINT: The "valley of death" can last for 10 to 15 years until positive cumulative cash flow is achieved*

Clustering hydrogen stations around main demand centres and connecting corridors during the FCEV roll-out phase can ensure maximising utilisation rates. Several partnerships and initiatives, such as the California Fuel Cell Partnership (CaFCP) in the United States, $H_2$Mobility in Europe or the Fuel Cell Commercialisation Conference of Japan (FCCJ), have made proposals for the optimal roll-out of hydrogen stations so as to provide maximum coverage at minimal cost. An overview of existing and planned hydrogen refuelling stations is given in Table 5.

To cover the negative cash flow period, direct public support might be needed for hydrogen stations during the FCEV market introduction phase. As recently published in a paper by Ogden et al, direct subsidies in the range of USD 400 000 to USD 600 000 per station might be required until cumulative cash flow becomes positive, assuming a fast uptake of the Californian FCEV market (Ogden, J. et al, 2014).

## Table 5: Existing public hydrogen refuelling stations and targets announced by hydrogen initiatives

| Country or region | Existing hydrogen refuelling stations | Planned stations | |
|---|---|---|---|
| | | 2015 | 2020 |
| Europe | 36 | ~80 | ~430 |
| Japan | 21 | 100 | >100 |
| Korea | 13 | 43 | 200 |
| United States | 9 | >50 | >100 |

Sources: Weeda et al. (2014), *Towards a Comprehensive Hydrogen Infrastructure for Fuel Cell Electric Cars in View of EU GHG Reduction Targets*; HySUT (2014), *Fuel Cell Vehicle Demonstration and Hydrogen Infrastructure Project in Japan*; FFC (2015), *Fuel Cell Commercialisation Conference in Japan (FCCJ)*, http://fccj.jp/hystation/index.html#hystop; personal contact with US Department of Energy.

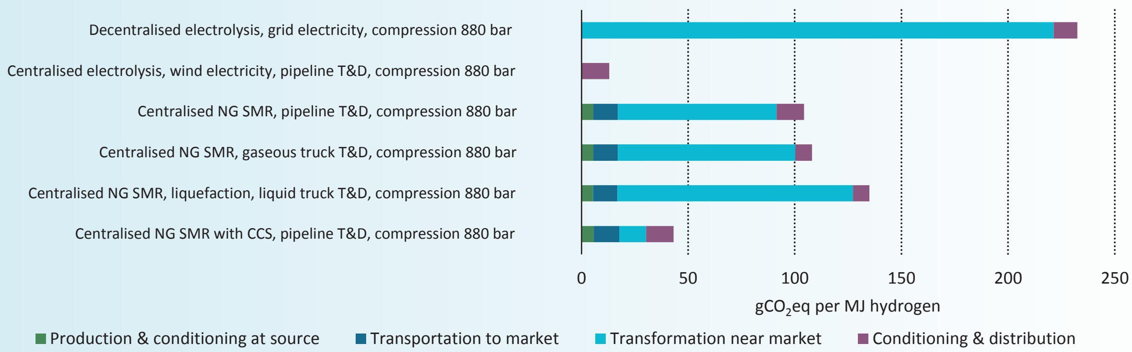
## Box 2: Carbon footprint of hydrogen used in transport

The carbon footprint for different hydrogen pathways and for gasoline and diesel are shown in Figure 4 for the European Union. Depending on the production and T&D pathway, today's carbon footprint for hydrogen can be significant. Decentralised hydrogen production (at the refuelling station) using today's EU grid electricity mix, and including compression to 88 MPa, results in a carbon footprint which is almost three times higher than that for gasoline or natural gas. Conversely, when produced from renewable power, biomass or fossil fuels with CCS, the carbon content of hydrogen can be reduced to below 20 $gCO_2eq$ per MJ. Still, in combination with the higher efficiency of FCEVs, the use of hydrogen from natural gas SMR without CCS results in lower per kilometre emissions than the use of gasoline in comparably sized conventional cars (see also Figure 2).

Hydrogen T&D and retailing ("Conditioning and distribution") have a substantial carbon emission contribution, which is mainly due to the energy-intense compression of the hydrogen gas to 88 MPa, but also due to hydrogen T&D using trucks (with hydrogen either in gaseous or liquefied form) or pipelines. The values shown in Figure 4 are for the European Union and contain relatively long transmission distances for natural gas of 4 000 km ("Transportation to market"). Since transmission distances might be shorter in the United States, carbon footprint values could be slightly lower, while LNG supply in Japan would lead to higher specific carbon emissions. Furthermore, the comparison suggests that the liquefaction of hydrogen for T&D purposes leads to around 25% to 30% higher carbon emission compared to gaseous truck or pipeline transport.

In the future, the carbon footprint of low-carbon hydrogen could be reduced further if low-carbon electricity was used for compression.

### Figure 4: Today's carbon footprint for various hydrogen pathways and for gasoline and compressed natural gas in the European Union




Source: adapted from JRC (2013), Technical Reports – Well-to-tank Report Version 4.0 – JEC Well-to-Wheels Analysis, Joint Research Centre, Publication Office of the European Union, Luxembourg.

***KEY POINT: Depending on the generation, T&D and retail pathway, the carbon footprint of hydrogen can vary between almost 20 and more than 230 $gCO_2$ per MJ.***

## Hydrogen for VRE integration

The integration of large shares of VRE into the energy system will go hand-in-hand with the need to increase the operational flexibility of the power system. This implies the need to store electricity that is not needed at the time or the place of generation, or to transform it in a way that it can be used in another sector of the energy system.

A wide range of options and strategies exist to integrate high shares of variable generation (in the order of 30% to 45% in annual electricity generation) cost-effectively without the use of large-scale seasonal storage (IEA, 2014c). However, taking into account the full range of local conditions (such as regulatory and market structure, the status of existing and planned grid infrastructure investments) when analysing potential deployment opportunities for energy storage technologies, or attaining even higher VRE shares while also achieving the 2DS, can imply a greater need to apply such storage technologies at large scale.

### Table 6: Current performance of hydrogen systems for large-scale energy storage

| *Application* | *Power or energy capacity* | *Energy efficiency** | *Investment cost*** | *Lifetime* | *Maturity* |
|---|---|---|---|---|---|
| Power-to-power (including underground storage) | GWh to TWh | 29% (HHV, with alkaline EL) - 33% (HHV, with PEM EL) | 1 900 (with alkaline EL) - 6 300 USD/kW (with PEM EL) plus ~8 USD/kWh for storage | 20 000 to 60 000 hours (stack lifetime electrolyser) | Demonstration |
| Underground storage | GWh to TWh | 90-95%, incl. com-pression | ~8 USD/kWh | 30 years | Demonstration |
| Power-to-gas (hydrogen-enriched natural gas, HENG) | GWh to TWh | ~73% excl. gas turbine (HHV)<br><br>~26% incl. gas turbine (PtP) | 1 500 (with alkaline EL) - 3 000 USD/kW (with PEM EL), excl. gas turbine<br><br>2 400 (with alkaline EL) - 4 000 USD/kW (with PEM EL), incl. gas turbine (PtP) | 20 000 to 60 000 hours (stack lifetime electrolyser) | Demonstration |
| Power-to-gas (methanation) | GWh to TWh | ~58% excl. gas turbine (HHV)<br><br>~21% incl. gas turbine (PtP) | 2 600 (with alkaline EL) - 4 100 USD/kW (with PEM EL), excl. gas turbine<br><br>3 500 (with alkaline EL) - 5 000 USD/kW (with PEM EL), incl. gas turbine (PtP) | 20 000 to 60 000 hours (stack lifetime electrolyser) | Demonstration |

* = Unless otherwise stated, efficiencies are based on LHV.

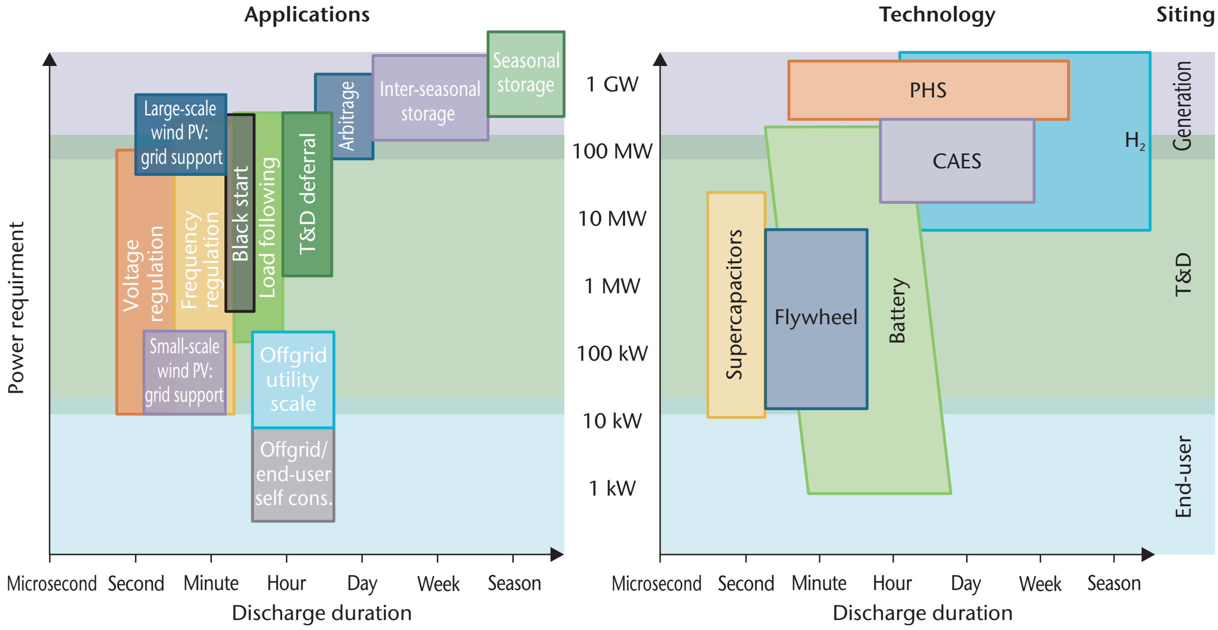
** = All investment costs refer to the energy output.

Notes: excl. = excluding; incl. = including; PtP = power-to-power; GWh = gigawatt hour; TWh = terawatt hour.

Source: IEA data; Decourt et al. (2014), *Hydrogen-based energy conversion. More than Storage: System Flexibility*; Giner Inc. (2013), “PEM electrolyser incorporating an advanced low-cost membrane”, 2013 Hydrogen Program Annual Merit Review Meeting; ETSAP (2014), *Hydrogen Production and Distribution*; Hydrogen Implementing Agreement Task 25 (2009), *Alkaline Electrolysis*; NREL (2009b), *Scenario Development and Analysis of Hydrogen as a Large-Scale Energy Storage Medium*; Saur (2008), *Wind-To-Hydrogen Project: Electrolyzer Capital Cost Study*; Schaber, Steinke and Hamacher (2013), “Managing temporary oversupply from renewables efficiently: Electricity storage versus energy sector coupling in Germany”, International Energy Workshop, Paris; Stolzenburg et al. (2014), *Integration von Wind-Wasserstoff-Systemen in das Energiesystem – Abschlussbericht*; US DOE (2010b), *Hydrogen Program 2010 Annual Progress Report – Technology Validation Sub-Program Overview*; US DOE (2014b), *Hydrogen and Fuel Cells Program Record*.

Electricity storage systems can be classified by size according to their input and output power capacity (megawatts [MW]) and their discharge duration (hours). These three parameters finally determine energy capacity (MWh). Together with the expected annual number of cycles, round-trip efficiency and self-discharge, the annual full-load hours can be determined. Location within the energy system and response time are other important parameters (see also the Technology Roadmap on Energy Storage [IEA, 2014b]). Hydrogen-based technologies are best suited to large-scale electricity storage applications at the megawatt scale, covering hourly to seasonal storage times (Figure 5).

## Figure 5: Electricity storage applications and technologies




Note: CAES = compressed air energy storage; PHS = pumped hydro energy storage.

*KEY POINT: Hydrogen-based electricity storage covers large-scale and long-term storage applications.*

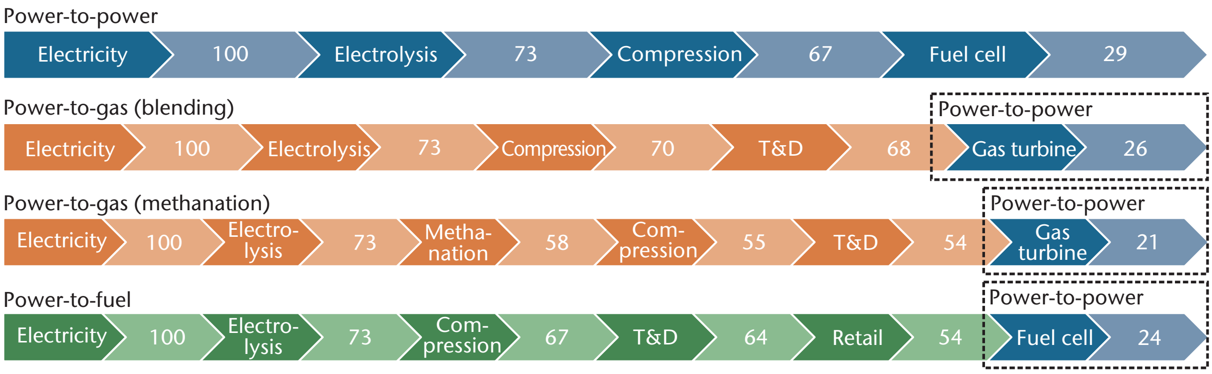
However, hydrogen-based systems to integrate otherwise-curtailed electricity are not restricted to electricity storage only. As mentioned before, hydrogen-based energy storage systems could be used to integrate surplus VRE electricity across different energy sectors, e.g. as a fuel in transport or as a feedstock in industry. They can be categorised as follows:

- Power-to-power: electricity is transformed into hydrogen via electrolysis, stored in an underground cavern or a pressurised tank and re-electrified when needed using a fuel cell or a hydrogen gas turbine.
- Power-to-gas: electricity is transformed into hydrogen via electrolysis. It is then blended in the natural gas grid (hydrogen-enriched natural gas – HENG) or transformed to synthetic methane in a subsequent methanation step. For methanation, a low-cost $CO_2$ source is necessary.
- Power-to-fuel: electricity is transformed into hydrogen and then used as a fuel for FCEVs in the transport sector.
- Power-to-feedstock: electricity is transformed into hydrogen and then used as a feedstock, e.g. in the refining industry.

All hydrogen-based VRE integration pathways are based on several transformation steps, which finally lead to rather low efficiencies over the whole conversion chain in the range of 20% to 30% (Figure 6). It is important to only compare final energies of the same quality, for example electricity either used in the power system or on board FCEVs. The greater the number of conversion steps included, the lower the overall efficiency.

The trade-off between power-to-power and power-to-gas options lies within the higher overall efficiency of pure power-to-power applications versus the possibility of using existing storage and T&D infrastructure for power-to-gas systems. The latter might be a strong argument in the near term – otherwise-curtailed renewable electricity could be integrated into the energy system via blending hydrogen to up to 5% to 10% in the natural gas mix, or transforming it directly to synthetic natural gas via methanation. Although no compatibility issues with subsequent end-use technologies arise in case of power-to-gas including methanation, the poor overall efficiency is likely to pose a substantial barrier for deployment.

## Figure 6: Current conversion efficiencies of various hydrogen-based VRE integration pathways




Note: The numbers denote useful energy; except for gas turbines, efficiencies are based on HHV; the conversion efficiency of gas turbines is based on LHV.

***KEY POINT: Total round-trip efficiencies of hydrogen-based energy storage applications are low.***

In an electricity system with high levels of VRE, it can be expected that supply will outstrip demand in some periods of the day and year. This has been labelled "excess" or "surplus" electricity. While some situations might be envisaged in which the storage operator incurs no costs, curtailed VRE electricity is generated at the same costs as VRE electricity required by the system, i.e. the consumer will pay for curtailed electricity through higher per unit electricity prices, since capital costs need to be recovered by selling less output electricity than in the case with no curtailment. Nevertheless, in this case, conversion efficiency has no impact on levelised costs of the final energy. However, using otherwise-curtailed VRE power to generate hydrogen poses an economic challenge for multiple reasons. Firstly, electrolysers have significant investment costs, which means that they will only be cost effective if they are operated for a sufficient amount of time during the year. As periods of surplus VRE generation will occur only for a limited amount of time, relying exclusively on generation surpluses is likely to be insufficient to reach sufficient capacity factors. Hence, it is likely that electricity with at least some value will be used for hydrogen production. Secondly, each conversion step on the way from electricity to hydrogen and back to electricity entails losses (Figure 6). Losses are of minor importance if the input electricity cannot be used for other applications, i.e. it would otherwise need to be curtailed. However, hydrogen generation will compete with other possible uses of surplus electricity, such as thermal storage. These challenges point to two areas for technology improvement: increasing efficiencies and reducing investment costs.

Only focusing on improving the technology is not sufficient; new and more integrated approaches need to be applied to create viable business cases.

As for all long-term, large-scale energy storage systems, annual full-load hours are limited. While technology components such as electrolysers and fuel cells remain expensive, all possible energy system services or by-products need to be exploited to the fullest extent possible, adopting the benefits stacking principle (IEA, 2014b).

When using electrolysers and fuel cells, a number of by-products, such as oxygen (during electrolysis) or process heat are produced, which need to be sold separately or used on site. In case of power-to-power systems, it is beneficial not only to sell power generated from low-value, surplus electricity, but also to provide ancillary services and to take part in the power control market. Here, the provision of controllable negative and positive load is remunerated.

Participating in different energy markets can help to create profits. Bi-generation (hydrogen and electricity) or even tri-generation systems (hydrogen, electricity and heat) offer the possibility of selling their products at the respective highest price, i.e. electricity and heat during times of peak demand and hydrogen to the transport sector, depending on the market conditions.

## Large-scale underground hydrogen storage

Storing hydrogen-rich gaseous energy carriers underground has a long history and became popular with the use of town gas to provide energy for heating and lighting purposes in the middle of the nineteenth century.

A geological formation can be suitable for hydrogen storage if tightness is assured, the pollution of the hydrogen gas through bacteria or organic and non-organic compounds is minimal, and the development of the storage and the borehole is possible at acceptable costs. Actual availability of suitable geological formations where energy storage is required is another limiting factor.

Comparing different underground storage options with respect to safety, technical feasibility, investment cost and operational cost, using salt caverns currently appears to be the most favourable option (Table 7), being already deployed at several sites in the United States and the United Kingdom.

## Table 7: Qualitative overview of characteristics of geological formations suitable for hydrogen storage

| | *Salt caverns* | *Depleted oil fields* | *Depleted gas fields* | *Aquifers* | *Lined rock caverns* | *Unlined rock caverns* |
|---|---|---|---|---|---|---|
| Safety | ++ | + | - | - | - | - |
| Technical feasibility | + | ++ | ++ | ++ | o | - |
| Investment costs | ++ | o | o | o | + | + |
| Operation costs | ++ | - | o | + | ++ | + |

Source: adapted from HyUnder (2013), *Assessment of the Potential, the Actors and Relevant Business Cases for Large Scale and Seasonal Storage of Renewable Electricity by Hydrogen Underground Storage in Europe - Benchmarking of Selected Storage Options*.

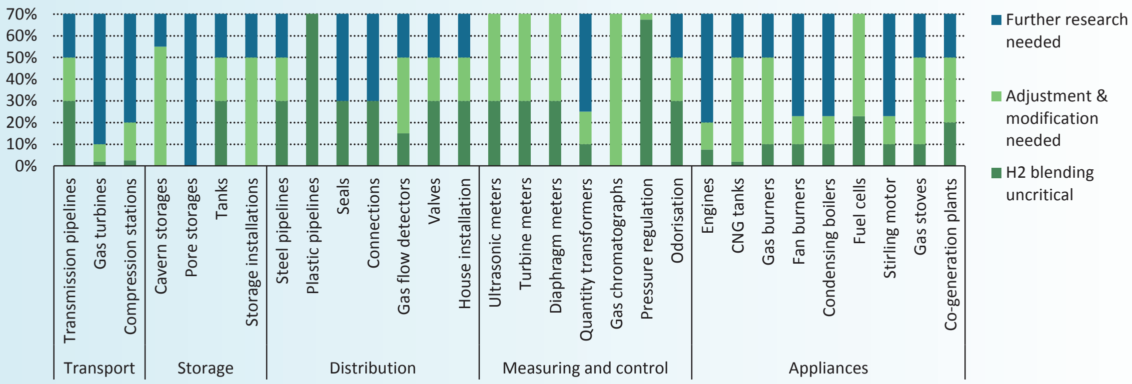
## Box 3: Power-to-gas in Europe: storage potential and limitations

Most developed countries have extensive natural gas T&D networks, including significant natural gas underground storage in depleted oil and gas fields, and salt caverns. This existing infrastructure offers huge energy storage potential if hydrogen produced from otherwise-curtailed renewable electricity was blended into natural gas (HENG). For example, the EU natural gas grid accounts for more than 2.2 million km of pipelines and about 100 000 million cubic metres of natural gas (which equals roughly 1 100 TWh) can be stored in dedicated storage sites (Eurogas, 2014). Assuming a volumetric blend share of 5% hydrogen in the natural gas, a theoretical storage potential of around 15 TWh of hydrogen (or roughly 9 TWh of output electricity) could be available using the existing natural gas storage infrastructure. If all natural gas used during a year in Europe was blended at the same share, more than 60 TWh of hydrogen (roughly equalling 36 TWh of output electricity) could be integrated in the energy system.

Blending hydrogen into the natural gas grid faces several limitations. First, the ability of hydrogen to embrittle steel materials used for pipelines and pipeline armatures necessitates upper blending limits of around 20% to 30%, depending on the pipeline pressure and regional specification of steel quality.

Second, the much lower volumetric energy density of hydrogen compared to natural gas significantly reduces both the energy capacity and efficiency of the natural gas T&D system at higher blend shares. At 20% volumetric blend share, flow rate needs to be increased by around 10% to provide the same energy to the customer, and pipeline storage capacity needed to balance intra-day fluctuations decreases by 20% (Decourt et al., 2014). By far the strongest restriction is set by compression stations and various end-use applications connected to the gas grid. According to a recent German study (Deutscher Verein des Gas- und Wasserfaches, 2013), compressing stations, gas turbines and CNG tanks (e.g. in CNG vehicles) currently restrict acceptable blend shares to 2% by volume without any further adjustment (Figure 7).

## Figure 7: Limitations on the blend share of hydrogen by application




Source: Deutscher Verein des Gas- und Wasserfaches (2013), *Entwicklung von Modularen Konzepten zur Erzeugung, Speicherung und Einspeisung von Wasserstoff und Methan in Erdgasnetz.*

***KEY POINT: The most critical applications with respect to the blend share of hydrogen are gas turbines, compressing stations and CNG tanks.***

A recent article in Hydrogen Energy (Gahleitner, 2013) provides a good overview of the technical and economical parameters of almost 50 power-to-gas pilot plants (of which the majority remain in operation), concluding that apart from the technical core components, design and size as well as control strategy and system integration have a significant influence on overall system efficiency. Unsurprisingly, efficiency, cost, reliability and lifetime of electrolysers are the main areas where improvement is needed. To date, few of the pilot plants have been operated for lengthy periods.

## Box 3: Power-to-gas in Europe: storage potential and limitations (continued)

In the near term, the potential of power-to-gas applications to contribute to VRE integration might be constrained to specific locations fulfilling a suite of prerequisites. It requires the local availability of significant amounts of otherwise-curtailed renewable power and an existing natural gas infrastructure with well-known end-use applications. Blend shares of up to 10% of hydrogen might be viable in local natural gas distribution networks, if modifications to gas turbines located downstream were applied and no CNG cars were supplied.

The summary report of the recent workshop titled ”Putting Science into Standards: Power-to-Hydrogen and HCNG” held at the Joint Research Centre (JRC) of the European Commission in Petten, concludes, amongst others, that setting a clear limit for blending hydrogen into natural gas is currently seen as “premature”. It underlines the need for harmonisation of current and future standards with regard to the allowed hydrogen content in gas mixtures, and points out at CNG vehicle tanks to be a main bottleneck for HENG application (JRC, 2014).

# Hydrogen in industry

Most of today’s hydrogen demand is generated and used on industrial sites as captive hydrogen. In the EU more than 60% of hydrogen is captive, one-third is supplied from by-product sources, and less than 10% of the market is met by merchant hydrogen (Kopp, A., 2013). In general, industrial hydrogen demand offers a significant potential for carbon emission mitigation, but the cost of low-carbon hydrogen is critical.

## Hydrogen in the refining industry

Most of the hydrogen used in the refining industry is used for hydro-treating, hydro-cracking and desulphurisation during the refining process. A steadily growing demand for high-quality, low-sulphur fuels, together with a decline in light and sweet crude oils, is leading to a growing demand for hydrogen. In the past, most of the required hydrogen was produced on site from naphtha, which itself is a refinery product, using catalytic reformation (Rabiei, 2012). Matching the hydrogen balance is becoming increasingly difficult, and therefore the oil refining industry is using more hydrogen from natural gas steam reformation, most often produced in large dedicated plants managed by industrial gas companies.

Under business-as-usual assumptions, it is estimated that by 2030 more than twice the amount of hydrogen will be used in the refining sector compared to 2005 (IFP Energies Nouvelles, 2008). Most of the growth is expected to take place in North and South America, where the impact of using super-heavy crudes and crude oil from oil sands is most significant. China could see a tripling in hydrogen demand in the refinery sector.

In addition to conventional fuel refining, the upgrading of second-generation, sustainable biofuels produced from lignocellulosic biomass might also demand considerable amounts of hydrogen for hydro-deoxygenation in the future. The decarbonisation of hydrogen can therefore have a significant impact on reducing the carbon footprint of conventional fuels and biofuels during the refining process.

Considerable experience in transmitting hydrogen via pipeline already exists. In the United States the existing hydrogen pipeline system amounts to some 2 400 km, while in Europe almost 1 600 km are already in place (Pacific Northwest National Laboratory, 2015).

## Hydrogen in the steel industry

Hydrogen is generated in the steel industry as part of by-product gases during the coke, iron and steelmaking processes. For the most part, these off-gases are used to contribute to on site thermal requirements.

Currently, 71% of steel production is based on the reduction of iron ore in conventional blast furnaces (World Steel Association, 2014) where coke, coal and/or natural gas are used as reducing agents. The resulting pig iron is then reacted with oxygen in a basic oxygen furnace in order to remove excess carbon content from the iron and to generate liquid steel.

Hydrogen-containing gases are generated during coke production (coke oven gas, COG), and also in the blast furnace (blast furnace gas, BFG) and the basic oxygen furnace (basic oxygen furnace gas, BOFG).[4] These gas streams globally represent around 8.0 EJ per year and can displace other fossil fuels for heating purposes once collected and treated for reuse on site. In 2012, around 68% were reused in iron and steel production processes; alternatively these gases are flared.

The more efficient use of by-product hydrogen during the steelmaking process can contribute to improved overall energy efficiency and hence reduced carbon emissions.

In order to minimise the need for investment in dedicated hydrogen production plants, by-product hydrogen could also be used as a fuel for FCEVs during the early stages of market introduction. However, purification and cleaning of the hydrogen gas necessary for further use in proton exchange membrane fuel cells (PEMFCs) is economically challenging.

Hydrogen-rich gases can also be used as a reducing agent in alternative methods of steel production. Both, the DRI process and the smelt reduction (SR) process allow the production of iron without the need for coke. As coke production is very carbon intensive, important emission reductions can be achieved when the whole process chain is assessed.

In DRI processes, further emission reductions are feasible with the use of hydrogen with a low-carbon footprint. Instead of using natural gas as reducing agent, hydrogen produced from fossil fuels with CCS or renewable electricity could significantly reduce carbon emissions, if available at competitive costs.

Several research programmes, such as the European-based Ultra-Low-Carbon Dioxide Steelmaking (ULCOS), have focused on improving the performance of DRI and SR processes and exploring alternatives to optimise the use of process gas streams as iron ore reducing agents. Within these programmes, alternative blast furnace arrangements have been developed that collect, treat and reuse the blast furnace top gas as a reducing agent within the process. Compared to a typical blast furnace, coke demand per tonne of pig iron has been significantly reduced.

In Japan, the process developed under the COURSE 50 research project ("$CO_2$ Ultimate Reduction in Steelmaking Process by Innovative Technology for Cool Earth 50") enables the introduction of hydrogen-enriched COG into the blast furnace to reduce carbon emissions. This research project also aims to separate and recover $CO_2$ from the BFG. The Korean consortium POSCO/RIST is also developing a conversion process to produce a hydrogen-rich gas from COG and $CO_2$ through steam reforming, which could be used for iron ore reduction in a blast furnace or SR process.

## Fuel cell technology in buildings

The co-generation of power and heat allows the waste heat that occurs during power generation to be used for heating purposes. This can significantly increase overall energy efficiency in the buildings sector. Decentralised generation of electricity and heat using micro co-generation systems enables this benefit to be realised in the absence of district heating networks. Many different natural gas-powered co-generation systems using ICEs are already available on the market.

Fuel cell micro co-generation systems powered by natural gas are an alternative to conventional ICE systems. Currently, the electrical efficiency of fuel cell micro co-generation systems is around 42%, being around 10 percentage points higher than for ICE micro co-generation systems. The downside is significantly higher investment cost: while ICE-based systems cost around USD 2 200 per kW, commercially available fuel cell systems typically cost more than USD 9 000 per kW for commercial applications (Pacific Northwest National Laboratory, 2013) and more than USD 18 000 per kW for home systems (Hydrogen and Fuel Cell Strategy Council, 2014; IEA AFC IA, 2014).

Fuel cell micro co-generation systems are either based on a PEMFC or a solid oxide fuel cell (SOFC), the latter providing much higher temperature heat. Although systems with up to 50 kW electrical output exist, most commercially available systems have electrical power outputs of around 1 kW, therefore being insufficient to fully supply the average US or European dwelling. However, in the Japanese

4. These gases typically contain hydrogen in the range of 39% to 65% by volume for COG, 1% to 5% by volume for BFG and 2% to 10% by volume for BOFG (European Commission, 2000).

## Table 8: Current performance of fuel cell systems in the buildings sector

| Application | Power or energy capacity | Energy efficiency* | Investment cost** | Life time | Maturity |
|---|---|---|---|---|---|
| Fuel cell micro co-generation | 0.3-25 kW | Electric: 35-50% (HHV)<br>Co-generation: up to 95% | <20 000 USD/kW (home system, 1 $kW_e$)<br><10 000 USD/kW (commercial system, 25 $kW_e$) | 60 000-90 000 hours | Early market introduction |

* = Unless otherwise stated efficiencies are based on LHV.

** = All investment costs refer to the energy output.

Notes: 1 $kW_e$ = kilowatt electric output.

Source: Pacific Northwest National Laboratory (2013), *Business Case for a Micro Combined Heat and Power Fuel Cell System in Commercial Applications*; Hydrogen and Fuel Cell Strategy Council (2014), *Strategic Roadmap for Hydrogen Fuel Cells*; IEA AFC IA (2014), *IEA AFC IA Annex Meeting 25*.

market more than 120 000 Ene-Farm fuel cell micro co-generation systems of that power category have already been sold under a government subsidy that lasted until September 2014.

All natural gas-based micro co-generation systems need a high difference between local natural gas and electricity prices, the so-called "spark-spread". Together with higher efficiency, annual availability and government incentives, the spark-spread forms the economic basis for selecting a micro co-generation system over grid electricity and conventional domestic hot water boilers for heating and hot water supply.

## Box 4: The Japanese Ene-Farm experience

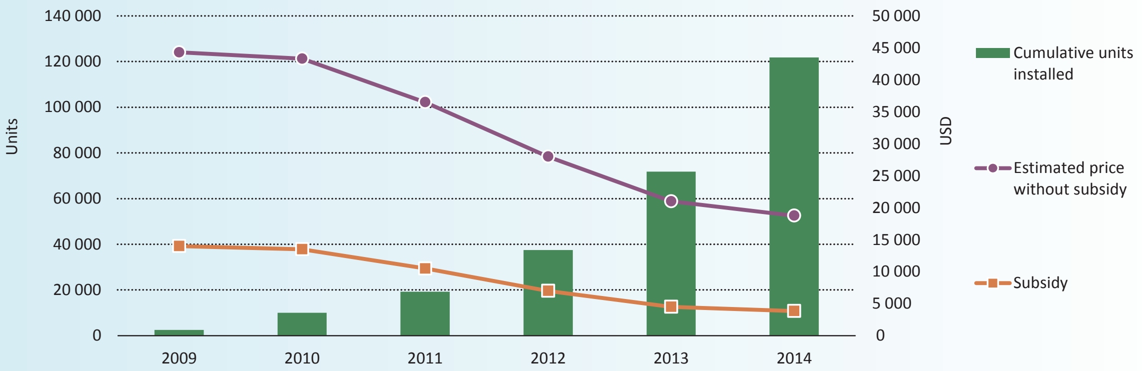
In 2009, a consortium of major Japanese energy suppliers and fuel cell manufacturers began marketing co-branded fuel cell micro co-generation units with an electrical output of between 700 W and 1 000 W to Japanese customers. The Ene-Farm system can be ordered with two different fuel cell types, using PEMFC and SOFC technologies, with PEMFC systems making up 90% of cumulative sales. With power output up to 1 kW, the system is not intended to cover the entire electricity demand of an apartment or family house, but to significantly contribute to the electricity demand and to fully cover the hot water demand.

Since their introduction, approximately 120 000 units have been installed in Japanese buildings (Figure 8). Initially a subsidy of almost USD 15 000 per unit was granted by the Japanese government, dropping to below USD 4 000 by 2014. Overall, the unit price had fallen from around USD 45 000 in 2009 to around USD 19 000 by 2014. This means that a learning rate of more than 15% (i.e. reduction in price per doubling of installed units) has been achieved during the large-scale demonstration phase.* The Ene-Farm system demonstrates that similar learning rates assumed for PEMFC units in the car-manufacturing sector are feasible at larger annual production volumes.

Nonetheless, to reach the target of several hundred thousand installed units in the near future, and millions of units by 2030 (as suggested by the Ene-Farm consortium), costs need to decline even further. So far, around 30% of the cost of the PEMFC unit is accounted for by the water tank (which is necessary for conventional boilers as well) and only 15% by the fuel-cell stack. The BOP (25%), the fuel-processing unit (15%) and the packaging (15%) account for the remaining 55% of total costs (Hydrogen and Fuel Cell Strategy Council, 2014). This means that further cost reductions will be harder to achieve, as the fuel stack is currently a relatively small share of the overall cost of the unit.

* To calculate the learning rate, year 2010 with almost 10 000 units installed has been taken as the baseline.

## Figure 8: Ene-Farm fuel cell micro co-generation cumulative sales, subsidies and estimated prices, 2009-14




Sources: Hydrogen and Fuel Cell Strategy Council (2014), *Strategic Roadmap for Hydrogen Fuel Cells*; IEA AFC IA (2014), IEA AFC IA Annex Meeting 25.

*KEY POINT: The price of Ene-Farm fuel cell micro co-generation systems has fallen by more than 50% since 2009.*

In Japan, equipping 10% of households (i.e. 5.3 million) with fuel-cell co-generation systems is estimated to cut total residential energy demand by 3%, resulting in 4% emission reductions compared to the use of gas boilers and grid electricity for residential energy supply.

Ene-Farm products are also intended to be sold on the European market, where differences in gas quality and much higher presence of potentially poisonous constituents in the European gas require the re-engineering of the gas processing unit for PEM systems.

# Other niche applications based on fuel cell technologies

Several other hydrogen-based niche applications exist that are currently applied across different sectors. These applications comprise fuel cell powered fork lifts, autonomous power systems for either stationary or portable off-grid applications, and uninterruptible power systems for back-up power.

Since 2009, over 8 200 fuel cell materials handling equipment units have been deployed in the United States. Benefitting from longer lifetimes and shorter and less-frequent refuelling cycles, fuel cell forklifts have demonstrated acceptable payback periods and improved cost-effectiveness compared to battery-powered forklift applications used in indoor warehouse operations (US DOE, 2014c).

Stationary fuel cell systems in the range of several kilowatts to multiple megawatts are used for remote power and back-up power applications. They are used to supply for example telecommunication towers, networking equipment or datacentres with resilient and reliable power. In these cases, fuel cell systems often replace diesel generators, providing longer lifetimes as well as less maintenance. The entire range of fuel cell types is represented within this market. While smaller systems in the range up to several kilowatts of output electricity are most often based on PEMFCs, bigger systems up to the multi-megawatt range mostly build on high-temperature fuel cells such as molten carbonate (MC) or solid oxide (SO) fuel cells. Many of the fuel cell systems rely on natural gas or hydrogen as primary fuel, but other liquid fuels such as methanol, ethanol, liquefied petroleum gas (LPG) and diesel or kerosene as well as gaseous fuels such as biogas, propane, butane and coal syngas are being used as well. In 2013, stationary fuel cell systems accounted for almost 90% of the shipped systems (US DOE, 2014a).

## Key hydrogen generation technologies

The following sections briefly discuss selected hydrogen generation technologies, such as reformers and electrolysers. The Technical Annex to this roadmap provides more detailed information on specific technical issues.

### Steam methane reforming

Around 48% of hydrogen is currently produced from natural gas using the SMR process, which is based on a reaction of methane and water steam at high temperatures in the presence of a catalyst. As $CO_2$ concentration in the exhaust gas is high, SMR units are promising candidates for the application of CCS technology, potentially leading to an 80% reduction in its carbon emissions.

Produced on a large scale, hydrogen costs mainly depend on the natural gas price, and are currently between USD 0.9 per kg in the United States, USD 2.2 per kg in Europe and USD 3.2 per kg in Japan.[5] Very small-scale reforming units exist with production rates down to 4.5 kg of hydrogen per hour, but generation costs are much higher and in the same order of magnitude as hydrogen produced via electrolysis (Table 9).

5. Based on IEA calculations taking into account current natural gas prices of USD 13 per MWh in the United States, USD 37 per MWh in the European Union and USD 56 per MWh in Japan.

### Table 9: Current performance of key hydrogen generation technologies

| Application | Power or capacity | Fficiency* | Initial investment cost | Life time | Maturity |
|---|---|---|---|---|---|
| Steam methane reformer, large scale | 150-300 MW | 70-85% | 400-600 USD/kW | 30 years | Mature |
| Steam methane reformer, small scale | 0.15-15 MW | ~51% | 3 000-5 000 USD/kW | 15 years | Demon-stration |
| Alkaline electrolyser | Up to 150 MW | 65-82% (HHV) | 850-1 500 USD/kW | 60 000-90 000 hours | Mature |
| PEM electrolyser | Up to 150 kW (stacks) Up to 1 MW (systems) | 65-78% (HHV) | 1 500-3 800 USD/kW | 20 000-60 000 hours | Early market |
| SO electrolyser | Lab scale | 85-90% (HHV) | - | ~1 000 h | R&D |

* = Unless otherwise stated efficiencies are based on LHV.

** = All investment costs refer to the energy output.

Notes: PEM = proton exchange membrane; SO = solid oxide.

Sources: IEA data; Decourt et al. (2014), *Hydrogen-Based Energy Conversion, More Than Storage: System Flexibility*; ETSAP (2014), *Hydrogen Production and Distribution*; FCH-JU (2014), *Development of Water Electrolysis in the European Union*, Fuel Cells and Hydrogen Joint Undertaking; Giner Inc. (2013), "PEM electrolyser incorporating an advanced low-cost membrane", 2013 Hydrogen Program Annual Merit Review Meeting; Hydrogen Implementing Agreement Task 25 (2009), *Alkaline Electrolysis*; IKA RWTH Aachen (n.d.), *On-site Hydrogen Generators from Hydrocarbons*, www.ika.rwth-aachen.de/r2h/index.php/On-site_Hydrogen_Generators_from_Hydrocarbons; Linde (n.d.), *Hydrogen*, www.linde-engineering.com/internet.global.linde engineering.global/en/images/H2_1_1_e_12_150dpi19_4258.pdf; NREL (2009a), "Scenario development and analysis of hydrogen as a large-scale energy storage medium", *RMEL Meeting*; Saur (2008), *Wind-To-Hydrogen Project: Electrolyzer Capital Cost Study*; Schaber, Steinke and Hamacher (2013), "Managing temporary oversupply from renewables efficiently: electricity storage versus energy sector coupling in Germany", International Energy Workshop, Paris; Stolzenburg et al. (2014), *Integration von Wind-Wasserstoff-Systemen in das Energiesystem – Abschlussbericht*; US DOE (2014b), US DOE (2010a), *Hydrogen Program 2010 Annual Progress Report - Innovative Hydrogen Liquefaction Cycle*.

Reforming processes are not limited to the use of natural gas. All hydrogen-rich gases can be used to produce pure hydrogen via adapted reforming processes. Following gasification as a first step, hydrogen can be produced from other fossil resources such as coal and also from biomass or organic waste materials.

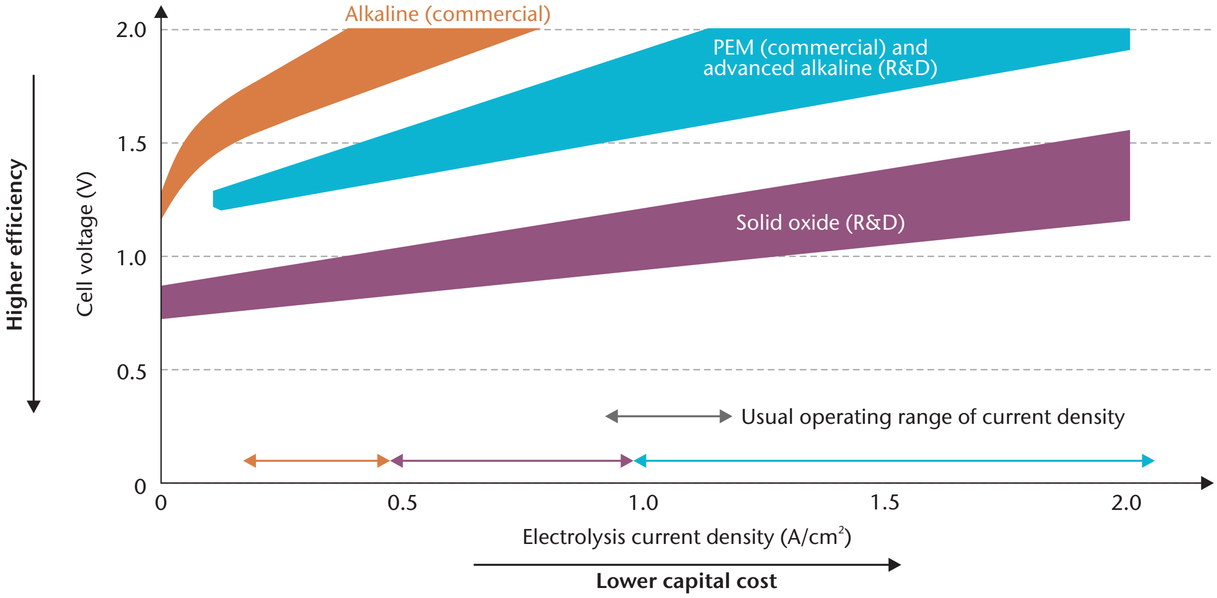
## Electrolysis

Electrolysis is a process of splitting water into hydrogen and oxygen by applying a direct current, converting electricity into chemical energy. Currently, around 8 GW of electrolysis capacity are installed worldwide (Decourt et al., 2014).

For electrolysers using only electric power (and no external heat) as input energy, the efficiency of hydrogen production decreases with cell voltage while the hydrogen production rate increases with cell voltage. At a given cell geometry, the operator therefore has to deal with a trade-off between electrolyser efficiency and hydrogen output.

Different types of electrolysers are distinguished by their electrolyte and the charge carrier, and can be grouped into: 1) alkaline electrolysers; 2) PEM electrolysers; and 3) SO electrolysers.

### Figure 9: Schematic representation of technology development potential of different electrolysers




Note: A/cm² = ampere per square centimetre.

Source: adapted from Decourt et al. (2014), *Hydrogen-Based Energy Conversion, More Than Storage: System Flexibility*.

***KEY POINT: Although alkaline electrolysers are a mature and affordable technology, PEM and SO electrolysers show a greater potential to reduce capital costs and to increase efficiency.***

All electrolysers consist out of the electrolyser stack, comprising up to 100 cells, and the BOP. Stacks can be mounted in parallel using the same BOP infrastructure, which is why electrolysers are highly modular systems. While this makes the technology very flexible with respect to hydrogen production capacity, it also limits the effects of economies of scale, as even large electrolysers are based on identically sized cells and stacks.

Alkaline electrolysers are currently the most mature technology, and investment costs are significantly lower than for other electrolyser types. Although alkaline electrolysers currently have higher efficiencies than electrolysers using solid electrolytes, PEM and SO electrolysers have much higher potential for future cost reduction and, in case of SO electrolysers, efficiency improvements (Figure 9). PEM electrolysers are particularly interesting as they show both the highest current density and operational range, prerequisites necessary to reduce investment costs and improve operational flexibility at the same time. As of today, cell lifetime is a limiting factor for PEM and SO electrolyser technologies.

The cost of electrolytic hydrogen is largely determined by the cost of electricity and the investment costs associated with the electrolyser. Minimising the costs of input electricity is likely to be accompanied by lower annual utilisation rates, as very low-cost, surplus renewable electricity will only be available for a limited amount of time per year, which further stresses the impact of investment costs. It is therefore important to find the right balance between reducing investment costs and achieving efficiency improvements.

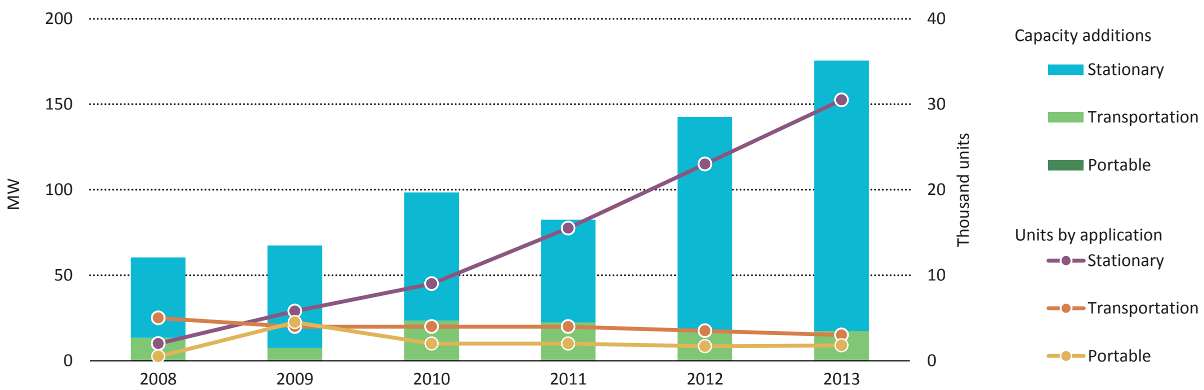
# Key hydrogen conversion and storage technologies

The following section briefly discusses selected hydrogen conversion and storage technologies. The Technical Annex to this roadmap provides more detailed information on specific technical issues.

## Fuel cells

Fuel cells allow the oxidation of hydrogen-rich fuel and its conversion to useful energy without burning it in an open flame. Compared to other single-stage processes to convert chemical energy into electricity, e.g. open-cycle gas turbines, their electrical efficiency is higher and in the range of 32% to up to 70% (HHV).

### Figure 10: Production volumes of fuel cells according to application




Source: US DOE (2014a), *2013 Fuel Cell Technologies Market Report*.

***KEY POINT: Currently, more than 80% of all fuel cells sold are used in stationary applications.***

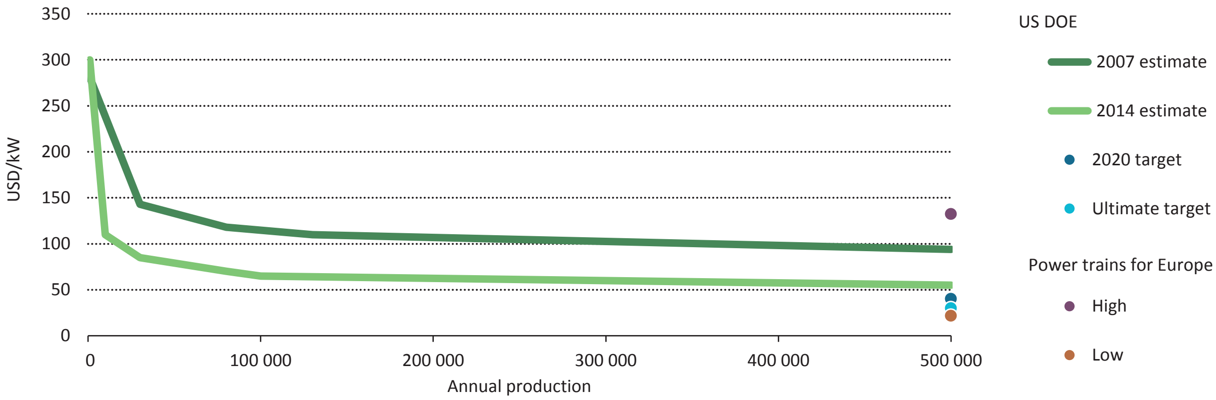
Fuel cells operate with a variety of input fuels, not only hydrogen. These include natural gas and also liquid fuels such as methanol or diesel. If pure hydrogen is used, the exhaust of fuel cells is water vapour and so has very low local environmental impact. However, if hydrocarbon fuels are used, using fuel cells for power generation produces $CO_2$ emissions, and so can only confer a climate benefit by operating at higher efficiency than alternative combustion methods. Nevertheless, experience with fuel cells based on hydrocarbons has a high value for low-carbon innovation due to the applicability of technological advances to fuel cells more generally. This is partly because hydrocarbon fuels are often reformed to hydrogen in a step that precedes the fuel cell and also because some hydrocarbons may be produced by lower carbon processes in future, e.g. methanol.

Similar to electrolysers, fuel cells are subject to a trade-off between efficiency and power output. Efficiency is highest at low loads and decreases with increasing power output. In comparison to conventional technologies, fuel cells can achieve their highest efficiencies under transient cycles, such as in passenger cars.

As in the case of electrolysers, different fuel cell types exist, which can mainly be distinguished by their membrane type and operating temperature.

Fuel cells can be categorised into: 1) PEMFC; 2) alkaline fuel cell; 3) phosphoric acid fuel cell (PAFC); 4) molten carbonate fuel cell (MCFC); and 5) SOFC. While PEMFCs and alkaline fuel cells have low operating temperatures of around 80°C, the others operate at higher temperatures of up to 600°C (SOFC), which makes them more suitable to combined heat and power applications. The higher the temperature, the better the efficiency at otherwise similar parameters. PEMFCs are the most suitable option for FCEVs.

## Figure 11: Production cost for PEMFCs for FCEVs as a function of annual production




Sources: adapted from McKinsey and Co. (2011), *A Portfolio of Powertrains for Europe: a Fact-Based Analysis, The Role of Battery Electric Vehicles, Plug-in Hybrids and Fuel Cell Electric Vehicles*; US DOE (2012), *Fuel Cell Technologies Program Record*; US DOE (2014d), *DOE Fuel Cell Technologies Office Record – Fuel Cell System Costs*.

*KEY POINT: Although current PEMFC systems for FCEVs cost around USD 300 to USD 500 per kW, cost can be reduced dramatically with economies of scale.*

According to the US Department of Energy (DOE) 2013 Fuel Cell Technologies Market Report (2014a), the global market for fuel cells grew by almost 400% between 2008 and 2013, with more than 170 MW of fuel cell capacity added in 2013 alone (Figure 10). Currently, more than 80% of fuel cells are used in stationary applications, such as co-generation, back-up and remote power systems. While the United States ranks first for fuel cell power capacity, Japan ranks first for delivered systems due to the successful upscaling of the Ene-Farm micro co-generation power system.

Although fuel cells saw remarkable development over the last decade, high investment costs and relatively limited lifetimes remain the greatest barriers to their wider application. Investment costs greatly depend on manufacturing cost, and could be significantly reduced with economies of scales. According to the US DOE (US DOE, 2012; personal contact with US Department of Energy), PEMFC systems for FCEVs show the highest cost reduction potential at high production volumes, and are targeted to ultimately reach costs of around USD 30 per kW (Figure 11), which would be equivalent to ICE engines.

Investment costs for stationary fuel cell systems are predicted to drop much more slowly, primarily due to the focus on higher efficiencies and longer life times. The target cost set by the US DOE for the 2020 time frame amounts to between USD 1 500 per kW and USD 2 000 per kW for medium-sized fuel cell co-generation systems (US DOE, 2011).

## Hydrogen gas turbines

While gas turbines adapted to burn gases with high hydrogen content (up to 45%) are commercially available, the same cannot be said for gas turbines capable of burning pure hydrogen. While technological modifications would be moderate, there is currently little demand for such equipment.

In the future, gas turbines able to burn very high shares of hydrogen will be needed for power generation based on the use of fossil fuels and pre-combustion CCS, e.g. in integrated gasification combined cycle (IGCC) power plants with CCS. This application is currently driving RD&D efforts in gas turbines able to burn gases with very high hydrogen content.

## Table 10: Current performance of key hydrogen conversion, T&D and storage technologies

| ***Application*** | ***Power or capacity*** | ***Efficiency **** | ***Initial investment cost*** | ***Life time*** | ***Maturity*** |
|---|---|---|---|---|---|
| Alkaline FC | Up to 250 kW | ~50% (HHV) | USD 200-700/kW | 5 000-8 000 hours | Early market |
| PEMFC stationary | 0.5-400 kW | 32%-49% (HHV) | USD 3 000-4 000/kW | ~60 000 hours | Early market |
| PEMFC mobile | 80-100 kW | Up to 60% (HHV) | USD ~500/kW | <5 000 hours | Early market |
| SOFC | Up to 200 kW | 50%-70% (HHV) | USD 3 000-4 000/kW | Up to 90 000 hours | Demon-stration |
| PAFC | Up to 11 MW | 30%-40% (HHV) | USD 4 000-5 000/kW | 30 000-60 000 hours | Mature |
| MCFC | KW to several MW | More than 60% (HHV) | USD 4 000-6 000/kW | 20 000-30 000 hours | Early market |
| Compressor, 18 MPa | - | 88%-95% | USD ~70 /kW$H_2$ | 20 years | Mature |
| Compressor, 70 MPa | - | 80%-91% | USD 200-400/kW$H_2$ | 20 years | Early market |
| Liquefier | 15-80 MW | ~70% | USD 900-2 000/kW | 30 years | Mature |
| FCEV on-board storage tank, 70 MPa | 5 to 6 kg $H_2$ | Almost 100% (without compression) | USD 33-17/kWh (10 000 and 500 000 units produced per year) | 15 years | Early market |
| Pressurised tank | 0.1-10 MWh | Almost 100% (without compression) | USD 6 000-10 000/MWh | 20 years | Mature |
| Liquid storage | 0.1-100 GWh | Boil-off stream: 0.3% loss per day | USD 800-10 000/MWh | 20 years | Mature |
| Pipeline | - | 95%, incl. compression | Rural: USD 300 000-1.2 million/km Urban: USD 700 000-1.5 million /km (dependent on diameter) | 40 years | Mature |

* = Unless otherwise stated efficiencies are based on LHV.

** = All investment costs refer to the energy output.

Sources: IEA data; Blum et al. (2014), "Overview on the Jülich SOFC development status", 11th European SOFC & SOE Forum, Lucerne; Decourt et al. (2014), *Hydrogen-Based Energy Conversion, More Than Storage: System Flexibility*; ETSAP (2014), *Hydrogen Production and Distribution*; IEA AFC IA (2015), *International Status of Molten Carbonate Fuel Cells Technology*; NREL (2009a), "Scenario development and analysis of hydrogen as a large-scale energy storage medium", RMEL Meeting; NREL (2010), *Molten Carbonate and Phosphoric Acid Stationary Fuel Cells: Overview and Gap Analysis*; NREL (2009b), *Scenario Development and Analysis of Hydrogen as a Large-Scale Energy Storage Medium*; Saur (2008), *Wind-To-Hydrogen Project: Electrolyzer Capital Cost Study*; Schaber, Steinke and Hamacher (2013), "Managing temporary oversupply from renewables efficiently: electricity storage versus energy sector coupling in Germany"; Stolzenburg et al. (2014), *Integration von Wind-Wasserstoff-Systemen in das Energiesystem – Abschlussbericht*; US DOE (2014b), *Hydrogen and Fuel Cells Program Record*; US DOE (2014d), *DOE Fuel Cell Technologies Office Record – Fuel Cell System Costs*; US DOE (2013), *Fuel Cell Technology Office Record - Onboard Type IV Compressed Hydrogen Storage Systems – Current Performance and Cost*.

Gas turbines able to react rapidly to changes in gas quality, especially with respect to hydrogen content, are necessary if blending hydrogen in the natural gas grid (power-to-gas) is to become a means of integrating otherwise-curtailed renewable power into the power sector.

## Compressors

Compressors are a key technology for hydrogen storage. Hydrogen pressure levels range from 2 MPa to 18 MPa for underground storage, over 35 MPa to 50 MPa for gaseous truck transport and up to 70 MPa for on-board storage in FCEVs. A recent study from the US National Renewable Energy Laboratory (NREL) concluded that very sparse data are available on compression technology at very high pressures (e.g. needed for FCEV on-board storage), with energy demand necessary for compression varying by a factor of ten among technologies (NREL, 2014). This is largely due to the fact that to date such high pressure compressors are produced in small numbers, as only very little demand exists.

## Hydrogen storage in tanks and solid structures

Mature options for storage of hydrogen in vessels comprise pressurised and cryogenic tanks, providing hydrogen storage capacities of between 100 kilowatt hours (kWh) (pressurised tanks) and 100 GWh (cryogenic storage). While pressurised tanks have high costs due to their limited energy density, cryogenic tanks provide limited storage time due to the boil-off stream losses, necessary to maintain acceptable pressure levels. An intermediary solution between pressurised and cryogenic hydrogen storage is cryo-compressed hydrogen. In this case, liquefied hydrogen is filled to the tank, but the pressures levels until hydrogen needs to be flared are much higher (up to 35 MPa) compared to cryogenic storage (around 2 to 4 MPa). This allows cryo-compressed hydrogen to be stored for longer time periods.

Storing hydrogen in metal hydrides or carbon nano-structures are promising technology options for achieving high volumetric densities. While metal hydrides are already in the demonstration phase, fundamental research is still needed to better understand the potential of carbon nano-structures.

# Vision for deployment to 2050

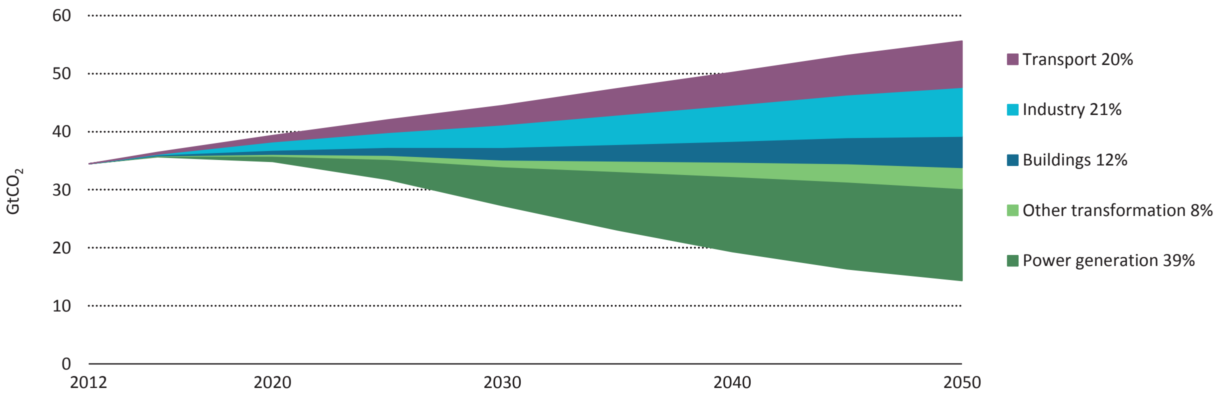
The *ETP* 2DS is set up to attain a carbon emission trajectory that limits global warming to 2°C. By 2050, total global energy-related carbon emissions need to more than halve compared to current levels. All energy sectors need to contribute if this ambitious target is to be achieved (Figure 12). Energy supply, including the power generation and fuel transformation sectors (termed "Other transformation" in Figure 12) will need to contribute almost half of the emission reductions.

Low-carbon energy systems largely rely on the deep decarbonisation of the power sector. The increased deployment of renewable energy, such as wind, solar, biomass and hydropower, is a key element in the supply of low-carbon electricity – by 2050, the global share of renewable electricity in the power sector is as high as 63% in the 2DS.[6]

The remaining half of the emission reduction necessary to achieve a 2°C trajectory will need to come from the energy demand sectors, namely transport, buildings and industry. This largely depends on the deployment of highly efficient end-use technologies, switching to low-carbon fuels such as hydrogen or advanced biofuels, or avoiding the use of energy through reduced activity levels – e.g. in the transport sector.

6. Renewable energy includes VRE such as wind, solar photovoltaic and ocean energy, plus renewable energy which is not classified as variable, such as hydropower, biomass, geothermal and concentrated solar power (CSP).

## Figure 12: Energy-related carbon emission reductions by sector in the *ETP* 2DS




Note: $GtCO_2$ = gigatonnes of carbon dioxide.

***KEY POINT: All energy sectors need to contribute to achieve the* ETP *2DS.***

The following sections outline how the intensified deployment of hydrogen technologies, essentially the "Vision", could contribute to achieving the 2DS. Detailed modelling results are provided for transport, based on a variant of the 2DS: the 2DS high $H_2$. As the analysis of hydrogen T&D and retail infrastructure requires country-specific evaluation, detailed results are only provided for the United States, Japan and EU 4 (France, Italy, Germany and the United Kingdom). A benchmarking approach is used in the power and industrial sectors, while a more qualitative discussion covers the vision for hydrogen applications in buildings.

## Transport

Although global transport activity is estimated to double between now and 2050 under a business-as-usual scenario, transport-related carbon emissions are halved compared with 2012 in the 2DS, thus contributing about 20% to total energy-related emission reductions (Figure 12). In 2012, road transport accounted for 75% of all transport emissions. It will therefore have to contribute the largest share to total transport sector emission reductions in the future.

Based on the *ETP* Avoid-Shift-Improve concept, carbon emissions can be reduced by: 1) avoiding travel, e.g. due to better urban planning and a significantly increased share of teleworking; 2) shifting travel to more efficient modes such as public passenger transport and rail freight; and 3) improving transport technologies. The "improve" option includes increasing the efficiency of conventional technologies, the rapid uptake of alternative vehicles such as BEVs, PHEVs and FCEVs, as well as switching to advanced biofuels, in particular for long-distance transport modes, such as long-haul road freight, air and shipping.

Box 5 provides an explanation of the *ETP* scenarios, and introduces the 2DS high $H_2$, which is then explored in further detail in the section below.

## Box 5: *ETP* scenarios and the hydrogen roadmap variant FCEV roll-out scenario

The *ETP* 2DS describes how technologies and energy-use patterns across all energy sectors may be transformed by 2050 to give a 50% chance of limiting average global temperature increase to 2°C. It sets a target of cutting energy-related $CO_2$ emissions by more than half by 2050 (compared with 2012). The 2DS acknowledges that transforming the energy sector is vital but not the sufficient solution; the goal can only be achieved if $CO_2$ and GHG emissions in non-energy sectors are also reduced. The 2DS is broadly consistent with the World Energy Outlook 450 Scenario through to 2040.

The model used for the analysis of the power and fuel transformation sectors is a bottom-up TIMES* model that uses cost optimisation to identify least-cost mixes of technologies and fuels to meet energy demand, given constraints such as the availability of natural resources. The TIMES energy supply model, which has been used in many analyses of the global energy sector, is supplemented by detailed demand-side simulation models for all major end-uses in the industry, buildings and transport sectors.

The IEA *ETP* 6DS is largely an extension of current trends. By 2050, global energy use increases by 75% (compared with 2015) and total GHG emissions rise by almost 60%. In the absence of efforts to stabilise atmospheric concentrations of GHGs, the average global temperature is projected to rise to up to 6°C in the long term. The 6DS is broadly consistent with the *World Energy Outlook* Current Policy Scenario through to 2040.

* TIMES stands for The Integrated MARKAL-EFOM System.

For the analysis of the transport sector, this roadmap builds on a variant of the *ETP* 2DS – the *ETP* 2DS high $H_2$. This scenario explores the effects on energy use, $CO_2$ emissions and costs if hydrogen enters the transport sector earlier and to a much greater extent than in the *ETP* 2DS, while delivering comparable emission reductions. The 2DS high $H_2$ follows "what if" logic, assuming twice the amount of FCEVs in both passenger (25% of the PLDV stock by 2050) and freight road transport (10% of the LCV, MFT and HFT stock by 2050) compared to the *ETP* 2DS. While the share of BEVs stays the same, the share of PHEVs is reduced in the *ETP* 2DS high $H_2$ compared to the *ETP* 2DS.

The rationale for investigating such a variant is based on the fact that a great deal of uncertainty surrounds technology choice in road transport, mainly due to the lack of maturity and commercialisation of key low-carbon transport options, as well as still-limited experience with respect to consumer acceptance. This, as a consequence, results in increased uncertainty about their long-term cost as carbon mitigation measures. In *ETP 2012* (IEA, 2012), a sensitivity analysis was conducted to better understand the role of hydrogen technologies in transport. Three cases, the *ETP* 2DS, the 2DS high $H_2$ and the 2DS no $H_2$ were compared with respect to carbon mitigation potential and cost. In a mature market, different mitigation options for the same mobility service – hybrids and PHEVs together with high shares of sustainable and low-carbon biofuels versus FCEVs in combination with low-carbon footprint hydrogen – showed comparable total costs and mitigation potential. However, the transition towards these different transport futures hinges on overcoming different barriers.

## Box 5: *ETP* scenarios and the hydrogen roadmap variant FCEV roll-out scenario (continued)

With the large-scale deployment of hydrogen technologies in transport, the economic barriers linked to the establishment of the hydrogen infrastructure are reduced if combined with rapid technology adoption, higher FCEV market penetration and thus higher hydrogen demand.

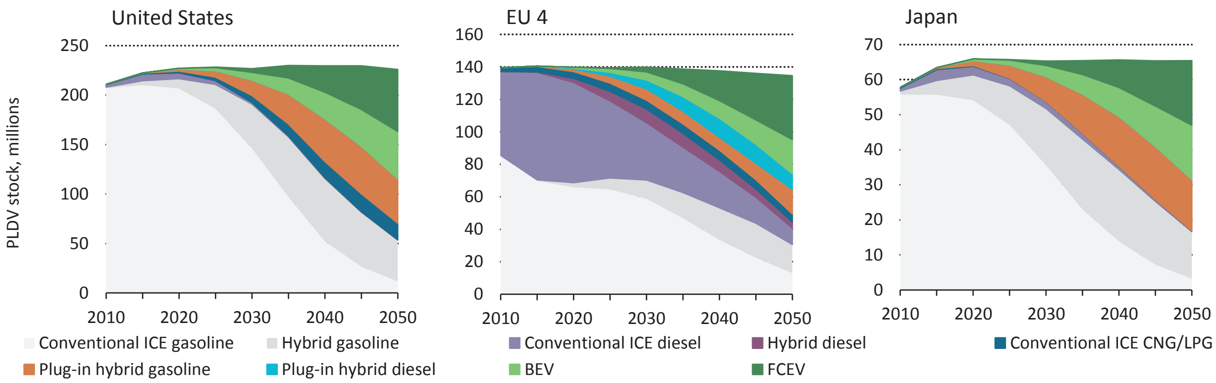
By building on the most optimistic scenario, this roadmap provides insights to an ambitious and yet feasible scenario aiming to minimise the need for subsidies to achieve parity of cost between FCEVs and efficient conventional vehicle technology.

## FCEV roll-out scenario

The PLDV stock within Europe, Japan and the United States is already close to the saturation point (Figure 13). Similar to the *ETP* 2DS, under the 2DS high $H_2$ total vehicle ownership is affected by avoiding transport and shifting demand to more efficient public transport modes.

The technology profiles of the PLDV fleet differ across the regions, in particular noting the large share of diesel passenger cars in Europe. In the future, the share of conventional ICE vehicles and hybrids without the option to plug into the power grid will need to drop to around 30% of the vehicle fleet, in order to attain the 2DS.

### Figure 13: PLDV stock by technology for the United States, EU 4 and Japan in the 2DS high $H_2$




Note: LPG = liquefied petroleum gas.

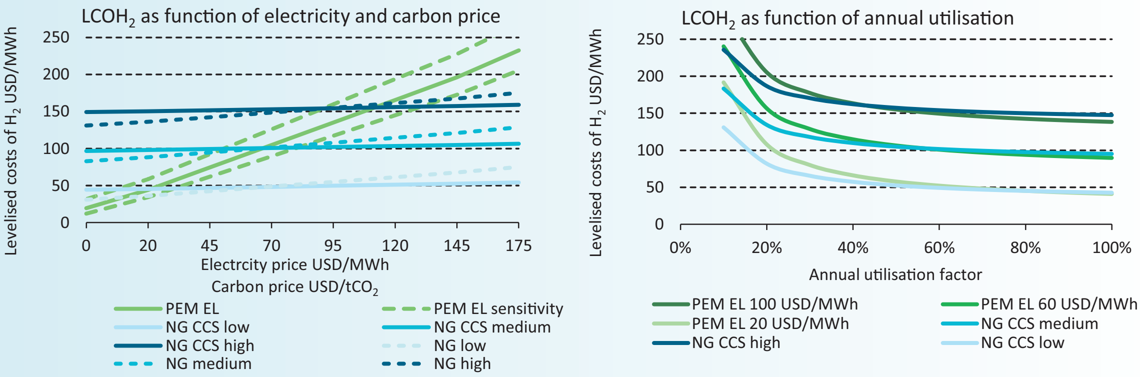
***KEY POINT: While in all regions the share of conventional vehicles drops below 10% by 2050, the technology mix remains region-specific.***

Compared to the *ETP* 2DS, the higher share of FCEVs in the 2DS high $H_2$ displaces some of the plug-in hybrid vehicles. While this ensures a similar emission trajectory, the need for biofuels is significantly reduced in the 2DS high $H_2$.

The FCEV sales scenario necessary to reach the PLDV stock shown in Figure 13 is very ambitious – it assumes that by 2020 around 30 000 FCEVs will have been sold in the United States, EU 4 and Japan. Cumulative sales reach about 8 million FCEVs by 2030. By 2050, the share of FCEVs in total passenger car sales is around 30%. Since FCEV production costs strongly depend on annual production rates, the fast ramp-up of FCEV sales is a prerequisite for rapidly decreasing FCEV cost. An overview of costs of PLDVs by technology as used in the model for the United States is provided in Table 11, detailed techno-economic parameters for FCEVs are provided in Table 12.

## Box 6: The economics of renewable hydrogen

### Figure 14: Cost of hydrogen as a function of electricity price and annual load factor




Notes: PEM EL = proton exchange membrane electrolyser; LCOE = levelised cost of energy; NG = natural gas; for the left-hand graph, annual loads of 85% are assumed for all technology options, and the dashed line marks the sensitivity of LCOE for hydrogen from a PEM electrolyser with a 30% variation in cost and a 10% variation in efficiency.

For hydrogen from natural gas, the terms low, medium and high denote: low – natural gas price: USD 20 per MWh, no T&D; medium – natural gas price: USD 40 per MWh, T&D: USD 25 per MWh of $H_2$; high – natural gas price: USD 60 per MWh, T&D: USD 50 per MWh of $H_2$.

***KEY POINT: Low-carbon electrolytic hydrogen requires low-cost renewable electricity and a combination of higher natural gas and carbon prices to be cost competitive.***

The adoption of renewable hydrogen versus the use of fossil-derived hydrogen (with or without CCS) strongly depends on its economic competiveness. The relationships between natural gas price, electricity price, annual full-load hours, carbon price and the resulting cost of hydrogen are illustrated in Figure 14. Even under optimistic assumptions with regard to the techno-economic parameters of the electrolyser, electrolytic hydrogen remains considerably more expensive than hydrogen from natural gas reforming, unless very low-cost renewable electricity is available and carbon or natural gas prices are high.

This is especially true as a combination of very low costs for electricity from VRE together with annual full-load factors above 30% is unlikely. While the results in the left-hand graph in Figure 14 are based on annual utilisation factors of 85%, the right-hand graph demonstrates the link between electricity prices, annual utilisation factors and hydrogen costs.

Natural gas SMR in combination with CCS appears to be an attractive option for hydrogen generation, if the carbon price is above USD 50 per tonne of $CO_2$. At low natural gas prices, renewable hydrogen would only be cost competitive if low-cost, low-carbon electricity was available for more than 80% of the hours of the year.

However, looking purely at hydrogen generation costs is not enough – costs for hydrogen T&D need to be taken into account to evaluate the competitiveness of renewable hydrogen. In case of large-scale natural gas SMR, hydrogen production takes place at centralised production facilities and transmission distances to the point of hydrogen use can be long, leading to high transmission costs. By contrast, the decentralised production of hydrogen via electrolysis can make hydrogen T&D obsolete.

At moderate daily hydrogen demand in the order of several tonnes, transmission costs of around USD 50 per MWh occur if hydrogen needs to be transported over a longer distance of 100 km; by comparison, if a shorter

## Box 6: The economics of renewable hydrogen (continued)

distance of 50 km is seen, T&D amounts to USD 25 per MWh (Yang & Ogden, 2007). Adding the transmission costs to the generation costs for centrally produced hydrogen using natural gas at USD 40 per MWh* together with SMR and CCS (NG CCS medium), renewable hydrogen could be cost competitive if produced from electricity at prices of up to USD 20 per MWh and at lower annual utilisation factors of around 15%. Alternatively, electricity prices of up to USD 60 per MWh at high annual utilisation factors of around 80% would also result in cost competitiveness with centrally produced low-carbon footprint hydrogen (NG CCS medium).

* For comparison, current natural gas prices account for USD 13 per MWh in the United States, USD 37 per MWh in the European Union and USD 56 per MWh in Japan.

## Table 11: Cost of PLDVs by technology as computed in the model for the United States

| | Today | 2030 | 2050 | Unit |
|---|---|---|---|---|
| Conventional ICE gasoline | 28 600 | 30 900 | 32 300 | USD |
| Conventional ICE diesel | 29 300 | 31 700 | 33 100 | USD |
| Hybrid gasoline | 30 000 | 31 800 | 33 200 | USD |
| Plug-in hybrid gasoline | 32 400 | 33 200 | 34 400 | USD |
| BEV (150 km) | 35 400 | 32 800 | 34 000 | USD |
| FCEV | 60 000 | 33 600 | 33 400 | USD |

Note: In line with results from the National Academy of Science report on "Transitions to Alternative Vehicles and Fuels" (National Research Council, 2013,) FCEVs become less expensive than plug-in hybrids by 2050. Similar tables showing the costs of PLDVs as computed by the model for Europe and Japan can be found in the Technology Annex.

## Table 12: Techno-economic parameters of FCEVs as computed in the model for the United States

| | Today | 2030 | 2050 | Unit |
|---|---|---|---|---|
| FCEV costs | 60 000 | 33 600 | 33 400 | USD |
| **Thereof** | | | | |
| Glider* | 23 100 | 24 100 | 25 600 | USD |
| Fuel cell system** | 30 200 | 4 300 | 3 200 | USD |
| $H_2$ tank** | 4 300 | 3 100 | 2 800 | USD |
| Battery** | 600 | 460 | 260 | USD |
| Electric motor and power control** | 1 800 | 1 600 | 1 400 | USD |
| **Specific costs** | | | | |
| Fuel cell system (80 kW) | 380 | 54 | 40 | USD/kW |
| $H_2$ tank (6.5 kg $H_2$) | 20 | 14 | 13 | USD/kWh |
| Battery (1.3 kWh) | 460 | 350 | 200 | USD/kW |
| **Other parameters** | | | | |
| Tested fuel economy | 1.0 | 0.8 | 0.6 | Kg $H_2$/100 km |
| Life time | 12 | 12 | 12 | Years |

Note: The USD DOE Fuel Cell Technology Office Record 13010 suggests total system costs of the 70 MPa hydrogen tank of USD 33 per kWh at annual production rates of 10 000 vehicles, dropping to about USD 17 per kWh at annual production rates of 10 000 vehicles (US DOE, 2013). A tested fuel economy of 0.8 kg$H_2$ per 100 km has been reported for the Toyota Mirai (Toyota, 2015a). The assumed tested fuel economy for today's FCEVs in the United States is higher based on the assumption that PLDVs are generally larger in the United States compared to Japan. They are in line with the results provided in the NREL FCEV demonstration project report (NREL, 2012a).

* future cost increase is due to light-weighting, improved aerodynamics, low resistance tyres and high efficient auxiliary devices.

** future costs are based on learning curves with learning rates of 10% ($H_2$ tank), 15% (electric motor, power control, battery) and 20% (fuel cell system) per doubling of cumulative deployment.

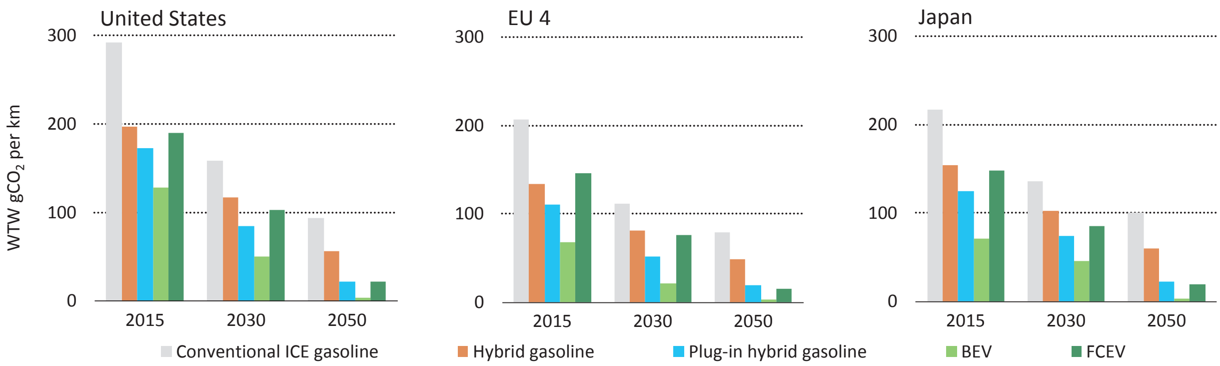
## Carbon footprint of FCEVs

The average on-road WTW $CO_2$ emissions of PLDVs in today's vehicle stock vary between almost 300 $gCO_2$ per km (conventional gasoline ICE cars in the United States) and a little more than 75 $gCO_2$ per km (BEVs in Japan), depending on the vehicle power train and the region (see Figure 15).

Although FCEVs and BEVs have no direct $CO_2$ emissions, their WTW carbon footprint is considerable accounting for emissions linked to hydrogen and power generation. Based on hydrogen from both natural gas SMR without CCS and grid electricity (see hydrogen generation scenarios Box 7), the $CO_2$ mitigation effect of FCEVs is moderate when compared to conventional ICE technology and hybrids, depending on the region. BEVs and, plug-in hybrids already have lower WTW emissions.

The specific emissions of FCEVs decline with the increasing decarbonisation of hydrogen supply, and finally fall below those of plug-in-hybrids. By 2050, FCEVs allow for very low-carbon, long-distance driving. At the same time, the use of FCEVs eases pressure on biofuel production. Although plug-in hybrids in combination with high blend shares of advanced biofuels in the gasoline mix (up to 40%) achieve comparable reductions in $CO_2$ emissions, they are dependent on the supply of sustainable biofuels. Since in the 2DS large amounts of high energy density, liquid biofuels are already needed for the decarbonisation of air and water transport, the reduced demand for sustainable biofuels in the road transport sector can enable a generally more sustainable transport pathway, especially in the very long term after 2050 (IEA, 2012).

### Figure 15: Specific PLDV stock on-road WTW emissions by technology for the United States, EU 4 and Japan in the 2DS high $H_2$



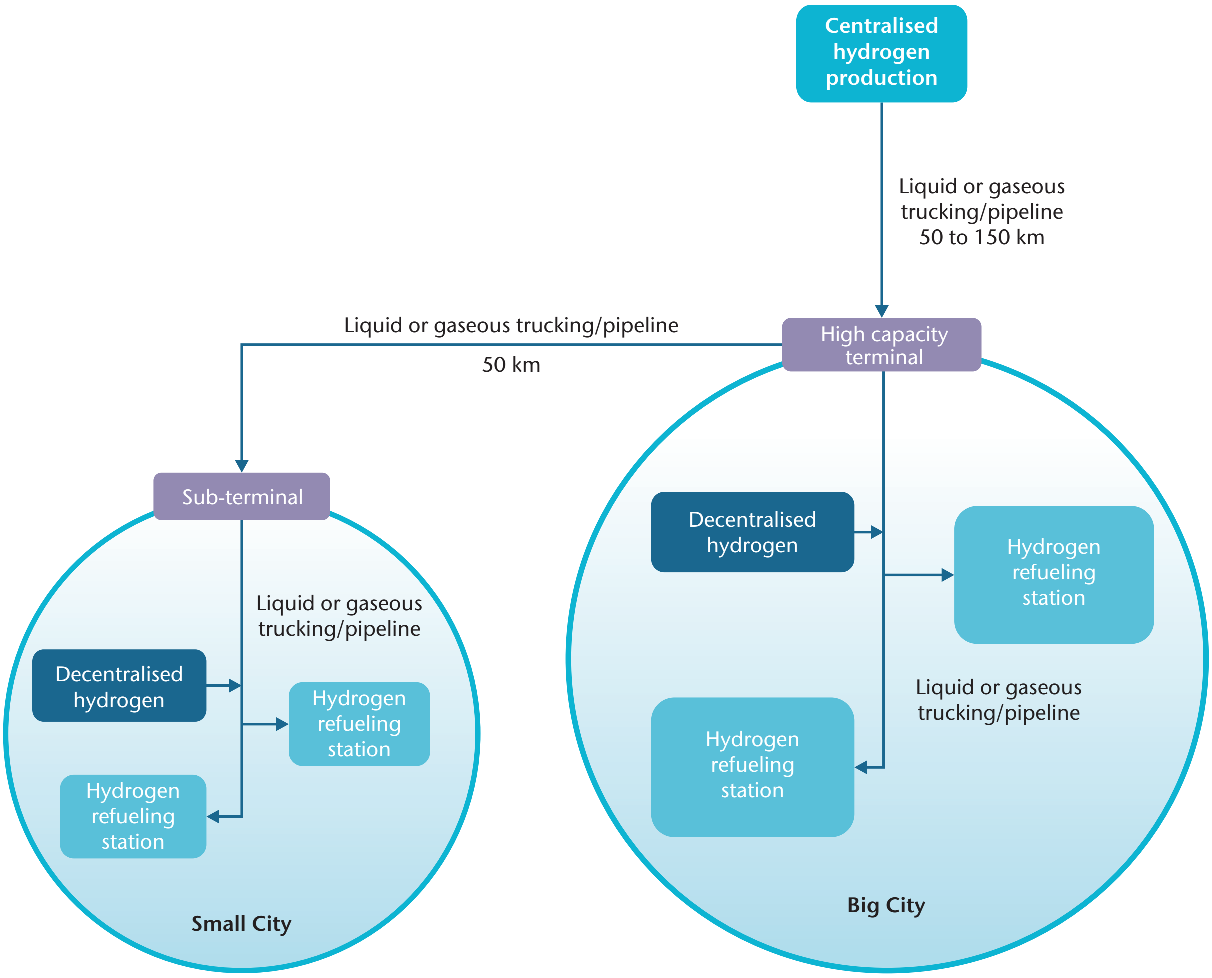

Note: Stock on-road WTW emissions include the upstream emissions from liquid fuel production as well as power and hydrogen generation. The fuel economy of the vehicle stock is based on the fuel economy of new vehicles sold, assumptions on average age and a gap factor of approximately 20%, accounting for the difference between test-cycle fuel economy and on-road fuel economy.

*KEY POINT: While FCEVs currently offer moderate WTW emission reductions compared to conventional PLDVs, they can enable low-emission, long-distance individual motorised transport in the longer term.*

## Hydrogen T&D and refuelling infrastructure

The configuration of hydrogen T&D and retail infrastructure is determined by many parameters, including: hydrogen demand; the distance to the hydrogen production site; the density of the urban environment; and assumptions on the required proximity of one station to the next for the consumer. As previously discussed, whether or not hydrogen is generated in a centralised manner also has significant impacts on T&D. As hydrogen T&D is costly and strongly depends on the transmission distance, more robust T&D cost estimates can only realistically be provided in knowledge of the geographical parameters.

## Figure 16: Scheme of hydrogen T&D and retail infrastructure as represented within the model




*KEY POINT: Different hydrogen generation, T&D and retail pathways will develop over time. In the underlying model scenario, the centralised supply of small cities happens via terminals based in large urban areas.*

### Hydrogen station roll-out

Modelling allows for a better understanding of the interaction between the key variables in the delivery of hydrogen T&D and retail infrastructure for FCEVs. A simple hydrogen T&D model has been introduced to the IEA Mobility Model. It distinguishes between hydrogen demand in large cities (~500 000 inhabitants) and hydrogen demand in small urban areas (~25 000 inhabitants), representing the size of typical settlements in the regions under discussion. As hydrogen transmission distance has a high impact on T&D costs, assumptions on average transmission distance between sites of production and demand, as well as the density of the retail station network, have a strong influence on hydrogen T&D costs. A schematic drawing illustrating some of the variables is provided in Figure 16.

Refuelling stations of two different sizes are represented in the model: daily refuelling capacities of 500 kg and 1 800 kg. Construction of small or large hydrogen stations depends on the FCEV fleet and the respective daily hydrogen demand.

Hydrogen can be delivered by truck (either in gaseous or liquefied form), or as a gas using hydrogen pipelines. Which approach to adopt for both long-distance hydrogen transmission as well as for intra-urban distribution is determined based on the optimal hydrogen T&D strategies provided in Yang and Ogden's paper (2007).

In the initial phase, hydrogen refuelling infrastructure is only available in large urban agglomerations and on some connecting routes. Based on regional differences in population density, assumptions on average speed and maximum acceptable time to the next hydrogen station, a basic station network is established. After 2030, in order to ramp up FCEV sales, the network needs to be expanded to "average-sized" cities. By 2040, in the 2DS high $H_2$ all cities need to have at least one hydrogen station.

## Box 7: Spotlight on hydrogen generation

Within the 2DS high $H_2$, hydrogen is produced from a broad variety of energy sources, depending on region-specific resource endowment, and subject to the carbon emission constraint to meet a 2°C target. Unlike the power generation mix, which is a result of the TIMES optimisation tool, hydrogen generation is based on a simulation approach, and the different hydrogen generation pathways are defined exogenously. In the model, hydrogen can be produced from natural gas via large-scale SMR with or without CCS, from coal via coal gasification and reformation with CCS, from biomass and from electricity. For hydrogen production from electricity via electrolysis, either grid electricity* or low-carbon, low-cost surplus** electricity is used. For all generation pathways, levelised cost of hydrogen generation is calculated based on economic parameters such as investment costs, fuel costs, carbon price, operation and maintenance costs and interest rate, as well as technological parameters such as conversion efficiencies, lifetimes and annual utilisation factors. Various other hydrogen generation pathways e.g. reformation of biogas or hydrogen production from waste water do exist but are not modelled explicitely.

* Within 2DS high $H_2$ the electricity mix of the 2DS published in *ETP* 2014 (IEA, 2014a) is used. Until 2050, power generation is almost completely decarbonised to meet the 2°C target.

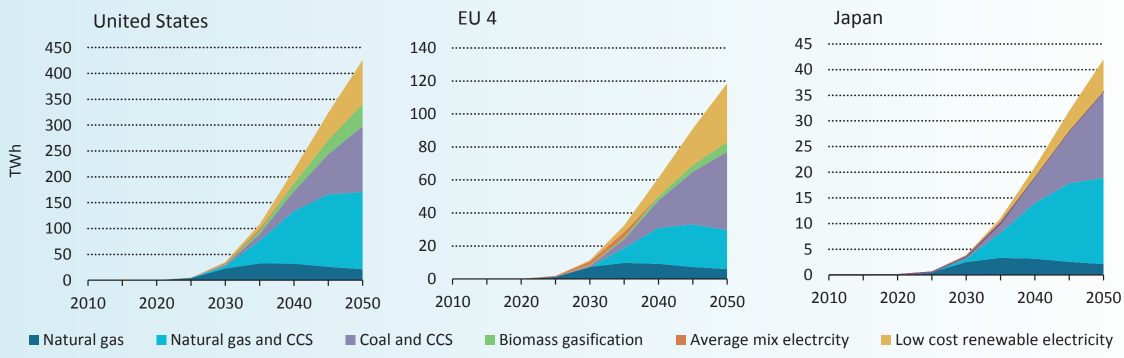
** Surplus electricity refers to electricity from VRE, which cannot be fed into the power grid due to either temporal or geographical mismatch between electricity generation and demand.

Surplus electricity is currently curtailed – if there is no demand and supply cannot be varied, leading to a market value of zero. In the future, otherwise-curtailed electricity will also have a lower price than its levelised cost of production. Estimating the amount of curtailed electricity in low-carbon power systems is a prerequisite to quantify the potential amount of cost-effective, renewable hydrogen. The amount of curtailed electricity as a function of the share of VRE in the power system has been recently published in a study by NREL (2012b). According to their results, annual curtailment levels of renewable power in the United States reach between 60 TWh and 150 TWh (4% to 7% of the generated renewable power per year), at renewable power shares between 60% and 90%. In theory, this would be sufficient to supply a fleet of around 6 million to 16 million FCEVs with renewable hydrogen. Other studies, (e.g. Mansilla, 2013; Jorgensen, 2008) document evidence of significant annual hours with electricity spot market prices of below USD 20 per MWh in countries with high VRE penetration.

The hydrogen generation pathways shown in Figure 17 are defined to meet the 2DS emission target at lowest cost and include carbon prices for emissions occurring during the fuel production process, which gradually increase up to USD 150 per tonne of $CO_2$ by 2050.

## Box 7: Spotlight on hydrogen generation (continued)

### Figure 17: Hydrogen generation by technology for the 2DS high $H_2$ in the United States, EU 4 and Japan



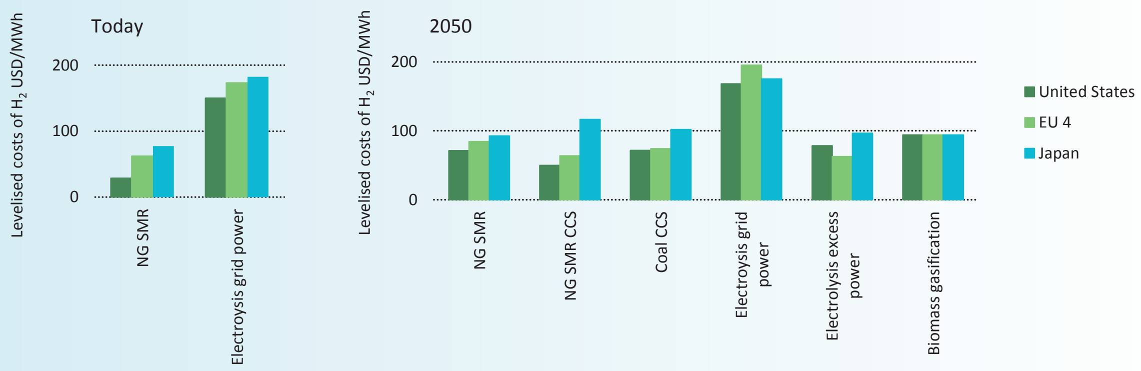

*KEY POINT: Hydrogen supply depends on regionally different resource endowments.*

During the early years, most of the hydrogen is supplied using natural gas SMR without CCS. After 2030, no new SMR capacity without CCS is added, since SMR with CCS*** is becoming cost competitive due to $CO_2$ prices of around USD 90 per tonne. Hydrogen from renewable electricity is only cost effective if low-cost, surplus electricity is used. Grid electricity at future retail prices (2050) of USD 115 (United States) to USD 137 (EU 4) per MWh is assumed to be cost-prohibitive, even if T&D costs are zero (Figure 18). It is estimated that low-cost, surplus renewable power would be sufficient to supply between 12% (Japan) and 30% (EU 4) of the hydrogen used in transport by 2050.**** Hydrogen production from biomass is assumed to play a minor role in all three regions.

*** For CCS technologies, capture rates of 80% are assumed. Furthermore, conservative cost estimates of USD 20 per tonne of $CO_2$ for transport and storage are included.

**** It is assumed that around 3% to 7% of annual renewable power generation is available at prices of around USD 20 to USD 30 per MWh for 1 370 to 2 140 hours of the year, depending on the region.

### Figure 18: Hydrogen production costs without T&D for the 2DS high $H_2$




*KEY POINT: Hydrogen produced from grid electricity is costly compared to alternative generation pathways. For cost-effective renewable hydrogen, the availability of low-cost, surplus renewable electricity is a prerequisite.* *****

***** All underlying technoeconomic assumptions can be found in Table 15

To cost effectively meet future hydrogen demand, an important share of generation is based on fossil fuels in combination with CCS.****** Alternative scenarios envisaging higher shares of hydrogen from renewable electricity are feasible, especially if the use of CCS is constrained by political choices or a lack of available $CO_2$ storage resources, although these alternatives are more costly. As hydrogen produced from grid electricity is significantly more expensive than hydrogen from SMR or from low-cost, surplus electricity, this will affect the cost of hydrogen at the station. Hydrogen demand from the transport sector accounts for between 1% (EU 4 and Japan) and 3% (United States) of total final energy demand and between 4% (Japan) and 10% (United States) of total electricity demand in 2050. Significantly increasing the share of hydrogen from renewable electricity in the generation mix would require substantial additions to renewable power capacity.

****** In Japan, hydrogen from natural gas or coal with CCS is assumed to be imported either as liquefied hydrogen or in chemically bound form. Transport costs are taken from: Inoue (2012).

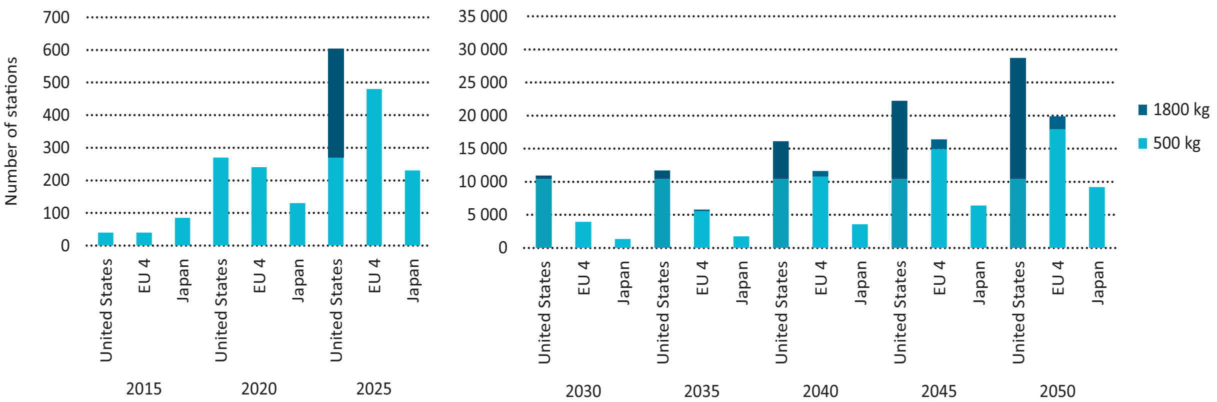
A station roll-out scenario, which corresponds to the assumed FCEV penetration, is shown in Figure 19. As annual mileage in the United States is much higher than in Europe and Japan, an earlier and more widespread demand for large hydrogen stations is needed. More detailed results on T&D infrastructure requirements can be found in the Technology Annex for the regions under discussion.

Although the approach used is based on a simplistic representation of hydrogen refuelling infrastructure, it reveals some interesting insights. While the provision of affordable hydrogen in densely populated large urban areas can be reached over the course of ten years, it rapidly becomes costly when expanding the network to "average-sized" cities, as the number of hydrogen stations necessary to provide national and regional coverage quickly jumps to several thousands.

While within this exercise only two station sizes (500 kg per day and 1 800 kg per day) are taken into account, much smaller stations might be needed in the initial phase to achieve widespread coverage. A 100 kg per day station would be enough to refill a fleet of around 200 FCEVs over the year,[7] and could fulfil basic needs while avoiding excessive under-utilisation.

7. Assuming 10 000 km per year, 1.1 kg hydrogen per 100 km, and an annual load factor of 60% for the station.

## Figure 19: Hydrogen stations for the 2DS high $H_2$ in the United States, EU 4 and Japan




Note: By the end of 2015 already 100 hydrogen stations are planned to be built in Japan.

***KEY POINT: Due to higher mileages and larger cars, larger hydrogen stations are needed in the United States.***

The necessary hydrogen generation, T&D and retail infrastructure requires significant investment in the order of tens to hundreds of billions of dollars. As for any other fuel, these investments are recovered through the fuel price when selling hydrogen to the consumer.

Within the 2DS high $H_2$, the total cumulative investment in hydrogen generation, T&D and retail infrastructure up to 2050 amounts to USD 140 billion, USD 50 billion and USD 26 billion for the United States, EU 4 and Japan respectively. A more detailed breakdown of costs is provided in the Technology Annex. For each of the 150 million FCEVs sold between now and 2050 in the United States, EU 4 and Japan, between USD 900 to (Japan) to USD 1 900 (United States) needs to be invested in the built-up of the hydrogen generation, T&D and retail infrastructure.

**Total cost of driving and subsidy requirements**

Total cost of driving (TCD, see Box 8) can be used to estimate the level of subsidy necessary for FCEVs to achieve parity of cost with a benchmarking technology. For this purpose, efficient conventional cars have been selected as the benchmark within the 2DS high $H_2$.

During the market introduction phase, the TCD for FCEVs is much higher than for efficient conventional cars of the same segment (Figure 20). This is due to higher vehicle investment and higher fuel costs. While TCD on a pure cost basis reach parity with efficient conventional cars in the United States by 2040 in the 2DS high H2, TCD of FCEVs will always stay higher in EU 4 and Japan due to higher costs for hydrogen production. In order to represent the full range of costs to the consumer, regional fuel taxation schemes need to be included when calculating $TCD_{tax}$. Currently, petroleum taxes in the EU 4 and Japan are equal to around 100% of the cost of fuel at the station, while in the United States petroleum fuel taxes are far lower. For the purposes of projection, petroleum tax levels are assumed to stay constant for the EU 4 and Japan, while a moderate 30% petroleum tax is assumed for the United States.

Differentiated fuel taxation provides a mean to reach parity of cost of $TCD_{tax}$ with conventional cars as soon as possible. For that purpose, in contrast to petroleum fuels, hydrogen needs to remain untaxed until cost parity is achieved. If hydrogen were exempted from fuel taxation, FCEVs would become cost competitive with efficient conventional cars around 2035 in all three regions under the 2DS high $H_2$.

To generate early consumer interest in FCEVs, the differential in $TCD_{tax}$ with the benchmark technology before cost parity is achieved could be covered by direct subsidies, in addition to the fuel tax exemption. Figure 21 illustrates the relationship between FCEV vehicle stock (blue line), the absolute amount of direct subsidy per vehicle necessary to achieve cost parity with efficient conventional cars (orange line), and total FCEV government subsidy as a percentage of total petroleum tax revenue in that year (green line).

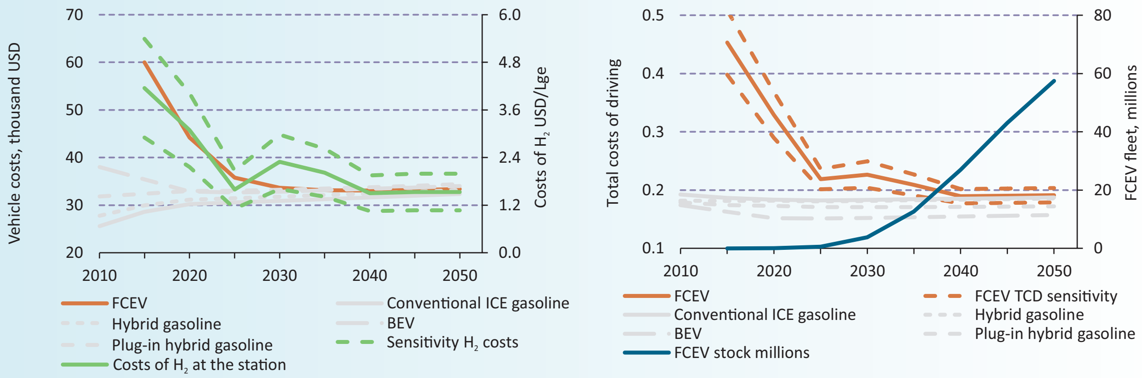
## Box 8: Vehicle costs, fuel cost and TCD

TCD is a valuable measure to compare different vehicle technologies on the basis of economics. TCD (expressed in USD per km) comprises the cost of the vehicle and fuel over the entire vehicle lifetime, divided by total driven kilometres.* Fuel costs comprise the cost of the fuel and costs relating to the T&D and retail infrastructure. When comparing vehicle technologies on a purely economic basis, non-monetary consumer preferences such as range, technology, image or subjective notions of reliability are not taken into account. In the following text, the US example will be discussed; results for EU 4 and Japan can be found in the Technology Annex.

With a rapid ramp-up of FCEV sales, vehicle costs drop quickly (Figure 20). Cost parity with plug-in hybrids is reached by 2030, and by 2040 FCEVs have almost reached the cost of conventional hybrids.

* With this approach, vehicle costs are depreciated over the entire vehicle lifetime. A discount rate of zero is applied.

## Figure 20: Vehicle costs, fuel costs and TCD for FCEVs in the 2DS high $H_2$ in the United States




***KEY POINT: While FCEV costs drop rapidly as sales ramp up, the cost of hydrogen at the pump drops much more slowly. Hydrogen costs decline quickly as long as stations are clustered around early demand centres. When the hydrogen refuelling network is expanded to provide the coverage necessary to sell millions of FCEVs, hydrogen costs see another increase.***

Costs of hydrogen at the station drop much more slowly, partly due to under-utilisation of the T&D and retail infrastructure. While the provision of affordable hydrogen in densely populated large urban areas can be reached over the course of ten years, costs increase significantly when expanding the refuelling network to "average-sized" cities, which in this modelling approach is assumed to take place after 2025. Network expansion to connect the "average city" causes hydrogen costs to increase again, due to longer T&D distances, smaller stations and under-utilisation of the infrastructure.** However, nationwide coverage of the hydrogen refuelling network is a prerequisite to bringing millions of FCEVs on the road.

When comparing the TCD of different technology options, the relatively high level of costs associated with hydrogen delays cost parity with alternative technology options. Without any further incentives, the TCD of FCEVs reaches cost parity with conventional cars in the United States by 2040. At 30% lower hydrogen costs, parity would occur five years earlier. Assuming 30% higher hydrogen costs, parity would not occur at all. On the contrary, due to higher energy costs in Europe and Japan, FCEVs will not reach cost parity with high-efficiency conventional cars without further incentives, such as differentiated fuel taxation.

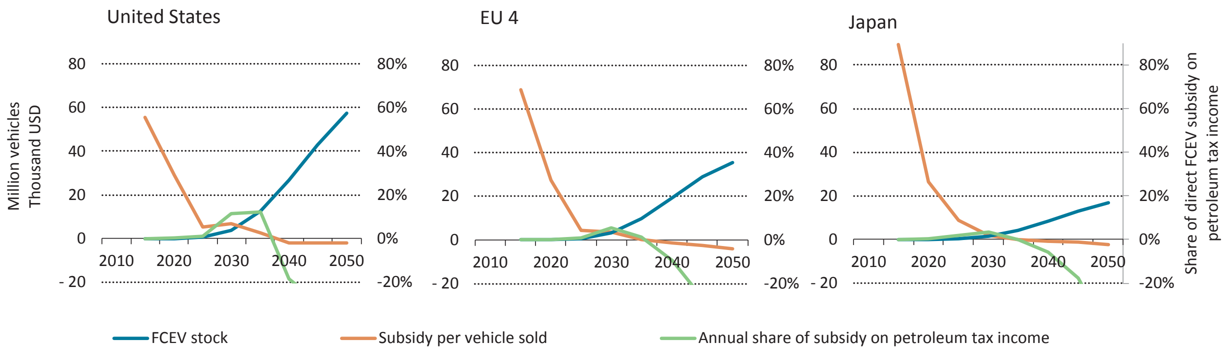
When comparing the TCD of FCEVs and BEVs, it is important to keep in mind that BEVs will not serve the same mobility service as FCEVs. BEV users will find that autonomy will be significantly more limited and recharging time will be longer. It is hence up to the consumer to choose between different mobility options at different costs.

** The fixed costs of the hydrogen T&D infrastructure are inversely proportional to the utilisation rate.

While direct subsidy levels per vehicle reach some USD 50 000 (United States) to more than USD 80 000 (Japan) during the very early market introduction phase, they quickly drop to around USD 5 000 per vehicle once the market is more mature, which is the case around 2025 within the 2DS high $H_2$. Although direct FCEV subsidies reach annual amounts of up to several billion USD, as a proportion of annual petroleum fuel tax revenue they would not exceed 5% in the EU 4 and Japan, and 15% in the United States.

Based on the scenario results including differentiated fuel taxation and assuming a rapid increase in FCEV sales, the market for passenger FCEVs could be fully sustainable 15 years after introduction of the first 10 000 FCEVs. Once the subsidy per FCEV (orange line) drops to zero (i.e. cost parity with conventional cars is reached), hydrogen could be taxed.

## Figure 21: Subsidy per FCEV and share of annual subsidy as a percentage of petroleum fuel tax revenue under the 2DS high $H_2$ in the United States, EU 4 and Japan




***KEY POINT: If hydrogen was exempted from fuel taxes and rapid market penetration is assumed, the FCEV market would be fully sustainable 15 years after the introduction of the first 10 000 FCEVs.***

The level of subsidy for FCEVs as a proportion of petroleum tax revenue reaches its peak when the FCEV fleet is already in the millions. This analysis therefore also illustrates that the critical phase of subsidy for the large-scale introduction of FCEVs is in the medium rather than the short term. Cumulative subsidies additional to the fuel tax exemption of hydrogen to reach cost parity with efficient gasoline cars account for around USD 59 billion in the United States, USD 22 billion in EU 4 and USD 7.5 billion in Japan.

TCD is highly sensitive to the pace of FCEV market penetration. Were an absence of fuel cell trucks and light commercial vehicles to be assumed under this scenario, cumulative subsidies would increase by around 15%.[8] If only 25% of the envisaged passenger FCEVs and no fuel cell trucks at all were sold by 2050, cost parity with conventional cars would not be reached, unless consumers would be willing to pay a 5% to 10% premium per kilometre.

By comparison, the acceptance of a small premium on TCD of 1% to 2% for FCEVs compared to conventional cars would reduce the amount of subsidy significantly.

### Carbon mitigation potential

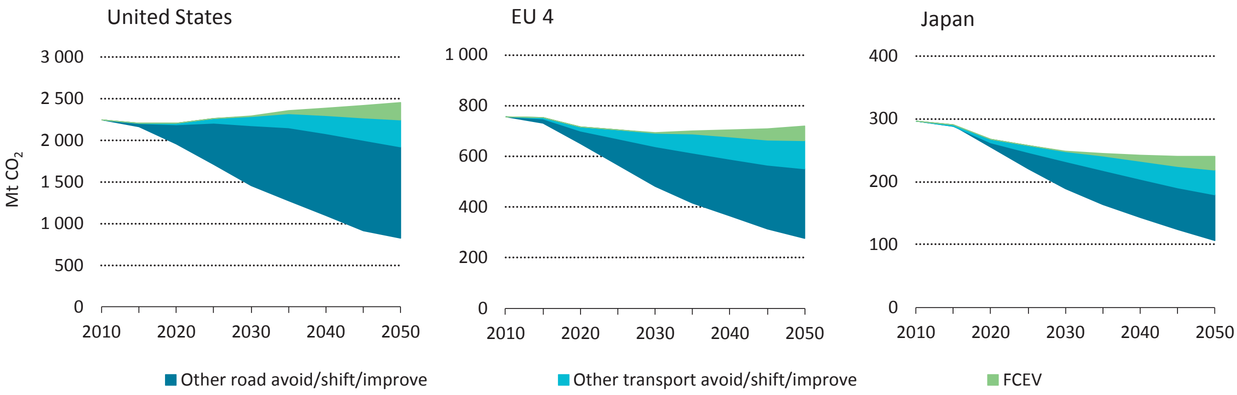
Under the 2DS high $H_2$, the large-scale deployment of FCEVs in passenger and freight road transport leads to significant $CO_2$ emission reductions (Figure 22). By 2050, FCEVs contribute around 14% of the overall annual transport emission reductions necessary to switch from a 6DS to a 2DS trajectory in the United States, EU 4 and Japan. Depending on the region, the contribution of FCEVs to cumulative total transport $CO_2$ emission reductions between now and 2050 accounts for between 7%

8. The presence of hydrogen trucks significantly affects the utilisation rates of the hydrogen supply infrastructure, as hydrogen demand per vehicle is much higher than for passenger cars. They therefore have an important impact on hydrogen demand and thus hydrogen costs at the station.

(United States) and 10% (Japan). Between now and 2050, almost 3 $GtCO_2$ are saved by FCEVs in the three regions under discussion.

Globally, by 2050 FCEVs could account for almost 1 $GtCO_2$ emission reductions per year, assuming a ten-year delay for FCEV market introduction and significantly lower growth rates in non-OECD regions compared to OECD regions.

## Figure 22: $CO_2$ mitigation from FCEVs in transport under the 2DS high $H_2$ in the United States, EU 4 and Japan



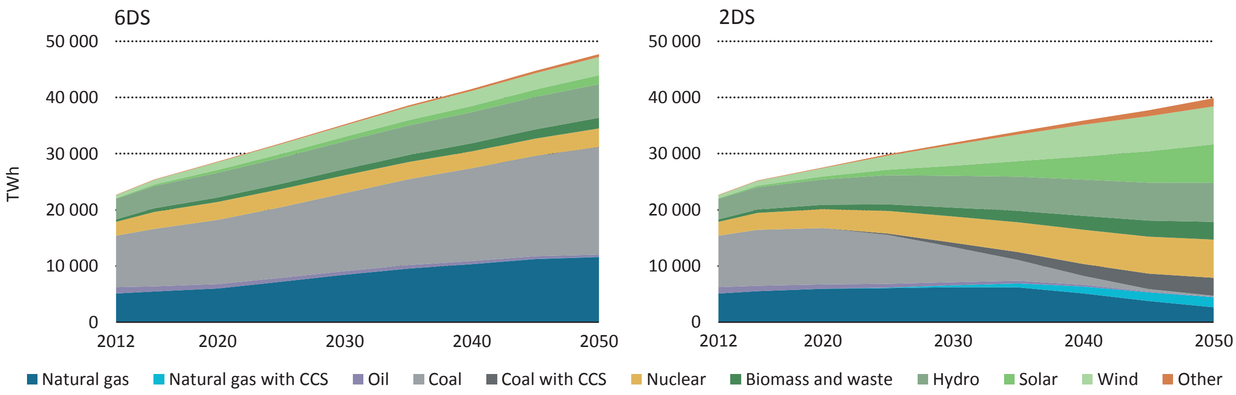

*KEY POINT: By 2050, the large-scale deployment of FCEVs in the transport sector could account for 14% of the annual carbon mitigation reductions necessary to switch from a 6DS to a 2DS emission trajectory.*

# VRE integration

Global electricity demand is estimated to double by 2050 under a business-as-usual scenario, compared to 2012 (Figure 23). It currently accounts for around 40% of total energy-related carbon emissions (IEA, 2015). The decarbonisation of electricity is pivotal to achieving the 2DS – by 2050 annual power-sector carbon emissions need to be reduced by more than 85% compared to 2012. Lower electricity demand resulting from more efficient processes across energy demand sectors accounts for about a quarter of total power-sector emission reductions. The remaining three-quarters need to come from drastic reductions in the carbon profile of electricity – its global average carbon intensity needs to drop to 40 grams of carbon dioxide ($gCO_2$) per kWh by 2050, from around 533 $gCO_2$ per kWh in 2012.

A drastic expansion in renewable electricity to 63% of the global power mix also requires the integration of high shares of VRE – up to 42%, depending on the region. VRE's intermittent nature significantly reduces the need for base load, i.e. power plants which are designed to run close to maximum output, almost full load, night and day during the whole year. Simultaneously, the demand for mid-merit order and peaking generation tends to increase, generating power at times of low VRE output and shutting down when VRE output is high. The use of energy storage technologies can effectively reduce the overall need for generation capacity, by storing power when it is available and releasing it during times of scarcity, thus also contributing to better utilisation of existing generation capacity. However, for a system-friendly deployment of a mix of renewable energy, interconnections, demand-side management, flexible hydropower or thermal generation are generally less costly options, which warrant being mobilised first.

## Figure 23: Global electricity generation mix under the 6DS and 2DS



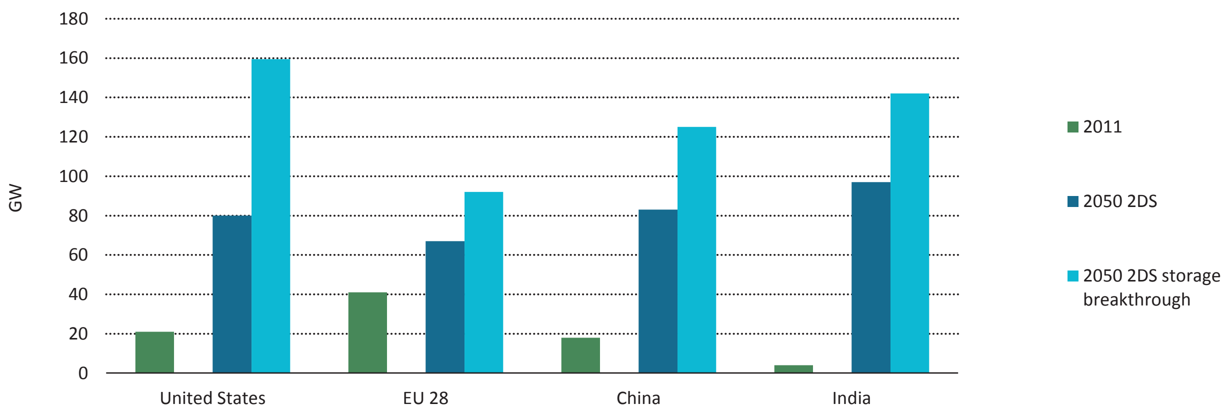

*KEY POINT: The power mix has to change drastically to reach the 2DS – while fossil fuels dominate today's power generation, the share of renewable power needs to increase to 63% globally by 2050.*

## Deployment of electricity storage

Different electricity storage scenarios have been investigated in the IEA *Technology Roadmap on Storage* (2014b). PHS already provides significant energy storage capacity of more than 80 GW in the United States, the European Union, China and India (Figure 24). While the modelling in the roadmap does not deal with VRE integration problems, such as grid congestion or spatial mismatch between electricity supply and demand, it nonetheless foresees the deployment of significant levels of electricity storage for power supply at times of high demand and low VRE supply. Under the 2DS, installed storage capacity more than quadruples and annual electricity output from energy storage reaches shares of between 3% and 9% of total VRE power generation in the regions shown (which account for roughly 60% of global power generation by 2050).

Under the 2DS, future costs for energy storage are assumed to be the same as today's costs of PHS. In the storage breakthrough scenario, investment costs are assumed to drop by 50%, leading to the creation of storage capacity six times greater compared to 2011.

## Figure 24: Installed electricity storage capacity for selected regions today and in 2050 under the 2DS and the storage breakthrough scenario




*KEY POINT: Under the 2DS, electricity storage accounts for up to 8% of total installed power capacity by 2050.*

## Hydrogen-based energy storage

Hydrogen-based energy storage systems cover a broad range of energy storage applications, with a focus on high power capacity and longer storage times in the range of hours to weeks, and even months. Benchmarking hydrogen-based energy storage systems against mature alternatives contributes to understanding their potential for large-scale deployment in the future.

This section compares LCOE of different hydrogen-based storage systems to those of the benchmarking technology in the respective field of application. In order to compare energy of the same quality, the comparison focuses on LCOE of output electricity, i.e. taking into account the final conversion step to electricity in case of power-to-gas applications.

### Table 13: Power-to-power and power-to-gas systems included in the analysis

| | *Key components* | *Abbreviation* |
|---|---|---|
| Power-to-power | PEM electrolyser, underground storage, PEMFC | $H_2$ PtP PEM/PEM |
| | Alkaline electrolyser, underground storage, PEMFC | $H_2$ PtP Alk/PEM |
| | PEM electrolyser, underground storage, hydrogen open-cycle gas turbine | $H_2$ PtP PEM/OCGT |
| | Compressed air storage | CAES |
| | Pumped hydro storage | PHS |
| Power-to-gas | PEM electrolyser, NG grid connection, open-cycle gas turbine | $H_2$ PtG PEM HENG with OCGT |
| | PEM electrolyser, methaniser, NG grid connection, open-cycle gas turbine | $H_2$ PtG PEM methane with OCGT |

Note: PtP = power to power; PtG = power to gas.

Two different storage applications have been identified where hydrogen-based systems can play a vital role – inter-seasonal energy storage and daily arbitrage. Table 13 provides an overview of the energy storage systems included in this analysis; the specifications for inter-seasonal storage and daily arbitrage are provided in Table 14. All techno-economic parameters of the different technology options can be found in Table 15.

### Table 14: System specifications for inter-seasonal energy storage and arbitrage

| | *Unit* | *Inter-seasonal storage* | *Arbitrage* |
|---|---|---|---|
| Power capacity charging | MW | 200 | 300 |
| Power capacity discharging | MW | 500 | 300 |
| Discharge duration | hours | 120 | 6 |
| Number of cycles per year | - | 5 | 274 |
| Annual full-load share | - | 7% | 17% |
| Cost of input electricity | USD/MWh | 0-20 | 0-50 |

Note: PtP = power to power; PtG = power to gas.

## Inter-seasonal energy storage

Inter-seasonal storage allows for temporary shifts in energy supply over weeks or months. In this example, the storage systems run five charging and discharging cycles at 500 MW power output over a discharging time of 120 hours each. All large-scale and long-term energy storage systems suffer from limited annual operation – the assumed scheme leads to 600 full-load hours per year, equivalent to a 7% annual utilisation factor. LCOE is therefore high, as the quantity of product sold on which to generate a return on investment is low.

Figure 25 shows the resulting LCOE for the different inter-seasonal storage systems listed in Table 13 for the years 2030 and 2050. Ranges illustrate the impact of input electricity cost. All storage options are benchmarked against an open-cycle gas turbine (OCGT),[9] which would be the alternative for meeting demand with flexible generation.

For power-to-power applications, hydrogen systems are most promising for inter-seasonal energy storage and surplus VRE integration in the future. They seem to be the only option to deliver LCOE somewhat close to the benchmark. Due to the much higher energy density of hydrogen with underground storage compared to PHS or CAES, investment costs are shifted from storage to the conversion technology.

Power-to-gas systems are close to the benchmark when assuming a low blend share of 5% hydrogen mixed with natural gas. However, even hydrogen from zero-cost electricity is expected to cost three times the natural gas price. Consequently, LCOE from power-to-gas systems appear unlikely to fall below the benchmark, unless extremely high $CO_2$ prices of more than USD 400 per tonne of $CO_2$ are assumed.

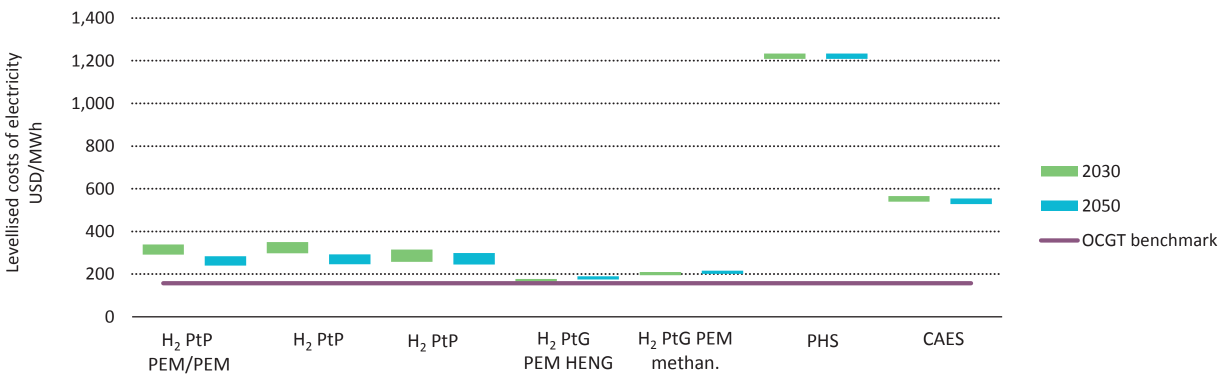
An advantage of a power-to-gas system that uses a gas turbine for re-electrification of a natural gas-hydrogen blend, is that it enables the use of existing infrastructure (including storage, T&D and re-electrification facilities) whereas alternative energy storage options rely on systems that need to be built from scratch. In addition, blending hydrogen into the gas grid means that the gas turbine can operate in the electricity market in the usual way. Unlike fuel cells in power-to-power electricity storage systems, its annual utilisation factor is not constrained by the utilisation factor of the electrolyser producing the hydrogen, which will likely be low if based on low-value, surplus renewable electricity.

If gas grids and gas turbines were able to deal with high and variable hydrogen blend shares above 20%, power-to-gas systems might also provide inter-seasonal energy storage by feeding more hydrogen into the blend at times of low VRE availability. Because annual average blend shares could remain at 5% and lower, the higher costs of the hydrogen in the blend would have only a marginal impact on average LCOE. In this manner, existing gas turbines could potentially achieve higher annual load factors while still meeting a fixed carbon budget and leveraging the sunk costs of the existing natural gas infrastructure.

The attractiveness of power-to-gas systems as a means of integrating high levels of VRE are economically dependent on declining electrolyser costs and technically dependent on persistent imbalances in electricity supply and demand. From a system perspective, making direct use of electricity, a high-quality form of energy, should be a priority wherever practicable. Thus, if future electricity systems evolve by 2050 to better balance supply and demand on a daily or seasonal basis, the window of opportunity for power-to-gas to play a transitional role in a lowest-cost decarbonisation pathway may be limited.

9. The costs of natural gas are those of the EU in the 2DS accounting for USD 35 per MWh in 2030 and USD 29 per MWh in 2050. $CO_2$ prices of USD 90 per ton of $CO_2$ in 2030 and of USD 150 per ton of $CO_2$ in 2050 are taken into account. For the OCGT an annual utilisation factor of 15% is assumed. The input electricity for the storage systems is assumed to be 100% renewable.

## Figure 25: LCOE for inter-seasonal energy storage via power-to-power systems and VRE integration via power-to-gas systems in 2030 and 2050




*KEY POINT: Looking ahead, hydrogen-based energy storage systems show the greatest potential to achieve acceptable LCOE for seasonal storage applications.*

## Daily arbitrage

Daily arbitrage allows for the shifting of stored electricity from times of low demand to times of high demand, taking advantage of the respective electricity price differential. Operated for daily arbitrage reasons, future hydrogen-based power-to-power storage systems almost achieve the performance of pumped hydro or compressed air storage, if very low-cost electricity is available (Figure 26). As the overall efficiency of the hydrogen-based systems is lower than for PHS and CAES (see Table 15), LCOE[10] is much more sensitive to the cost of electricity. Hydrogen-based storage systems would only work for arbitrage reasons with a very high spread of electricity prices between times of low and high demand. To break even with the 2DS storage benchmark, input electricity should cost no more than USD 10 per MWh by 2030 and USD 25 per MWh by 2050, which is unlikely to happen at the assumed annual utilisation factor for daily arbitrage.

For hydrogen-based power-to-power storage systems to achieve LCOE of USD 90 per MWh, as in the breakthrough scenario, the cost of investment attributable to both the electrolyser and the fuel cell would need to drop to around USD 400 per MWh, and efficiencies would need to increase to up to 90% for electrolysers and 60% for fuel cells (HHV). In addition, the electricity for arbitrage should cost no more than USD 20 per MWh. Consequently, it seems unlikely that hydrogen-based power-to-power storage systems will attain the breakthrough cost target.

## Marginal abatement costs of hydrogen-based energy storage options

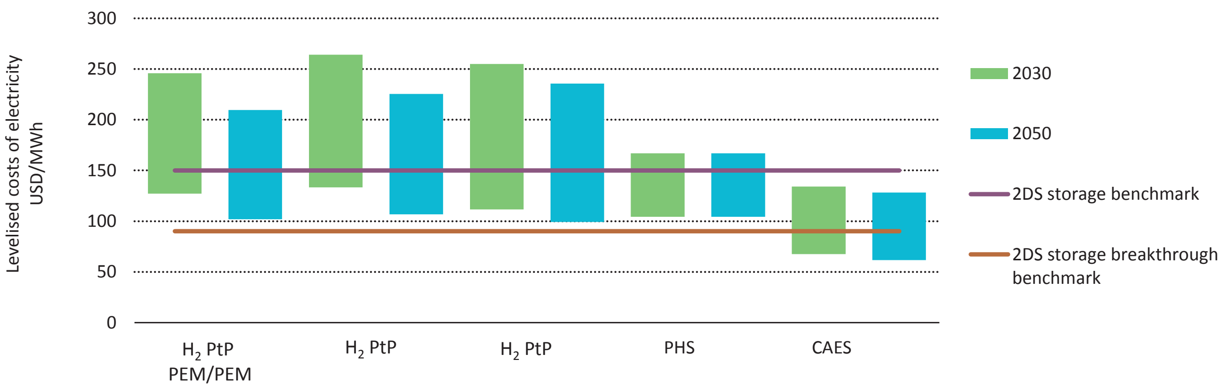
Examining $CO_2$ abatement costs allows the benefits of using hydrogen from otherwise-curtailed renewable power to be compared, addressing power-to-power, power-to-gas or power-to-fuel systems (Figure 27).[11] To ensure comparability, all systems are attributed the same annual full-load hours and input electricity prices in the same region. Figure 27 shows cost ranges among the United States, EU 4 and Japan. Cross-regional differences are caused by varying natural gas and electricity prices, as well as different annual full-load hours.[12]

10. The costs of natural gas are those of the European Union under the 2DS, accounting for USD 35 per MWh in 2030 and USD 29 per MWh in 2050. $CO_2$ prices of USD 90 per tonne of $CO_2$ in 2030 and USD 150 per tonne of $CO_2$ in 2050 are taken into account. The input electricity for the storage systems is assumed to be 100% renewable.

11. Power-to-power and power-to-gas systems are benchmarked against OCGTs fuelled with natural gas and operated at the *same annual full-load hours* as the energy storage system. Power-to-fuel applications are benchmarked against future high-efficiency gasoline vehicles fuelled with gasoline blend containing 30% second-generation biofuels.

12. Assumed costs for low-value VRE electricity range between USD 20 per MWh in the EU 4 and USD 30 per MWh in Japan, while annual full-load hours range between 1 370 hours in Japan and 2 130 hours in the EU 4.

## Figure 26: LCOE of different energy storage technologies for daily arbitrage in 2030 and 2050




*KEY POINT: Hydrogen-based storage technologies can be competitive at low electricity input prices.*

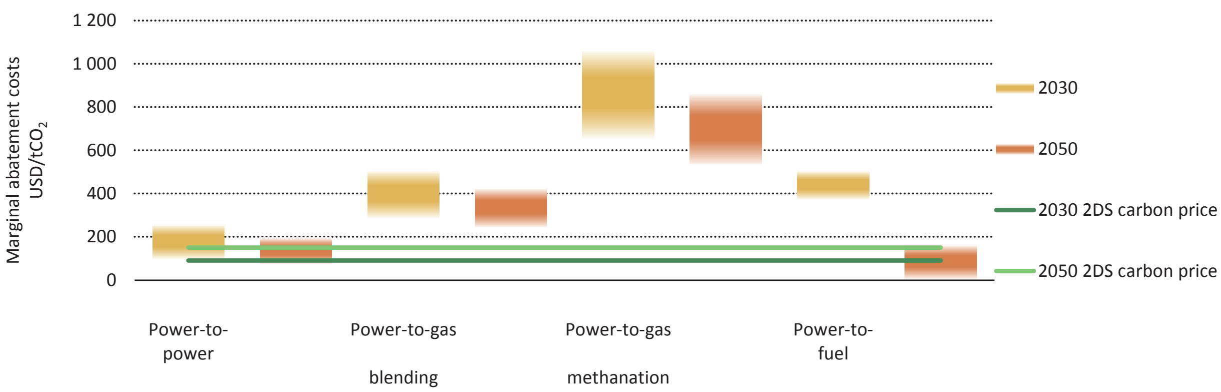
In the long term, power-to-fuel applications offer the lowest marginal abatement costs for hydrogen-based VRE integration. Cost reductions due to technological gains are greater than for other storage applications, as fuel cell systems in FCEVs are assumed to be mass produced under the 2DS high $H_2$.

By 2050, power-to-power systems can achieve mitigation costs of well below USD 150 per tonne of $CO_2$. Depending on the regional context, they can therefore be an attractive mitigation option under the *ETP* 2 DS, since the $CO_2$ price ranges between USD 150 and USD 170 per tonne by that time.

From a marginal abatement cost perspective, power-to-gas systems are the least promising option. They have lower LCOE compared to power-to-power systems, but since the blend share of carbon-free hydrogen or synthetic methane (in case of methanation) in the natural gas is only 5%, their emission benefit compared to burning pure natural gas is also limited. Since both blended natural gas and pure natural gas are burned using similar gas turbines, the abatement costs are simply the ratio between the price difference and the carbon intensity difference of blended natural gas (with pure hydrogen or with synthetic methane) and pure natural gas.

This again underlines the idea of power-to-gas options being a transition technology, making use of existing infrastructure.

## Figure 27: Marginal abatement costs of different hydrogen-based VRE power integration applications in 2030 and 2050




*KEY POINT: Power-to-fuel applications offer the lowest marginal abatement costs in the long term.*

# Industry

## Steel industry

Industrial direct $CO_2$ emissions peak in 2020 under the *ETP* 2DS (IEA, 2015), and innovative low-carbon processes become critical to achieving the 2DS in the long term.

The steel industry offers great emissions mitigation potential through improving energy efficiency, phasing out outdated technologies, switching existing processes to a lower-carbon fuel (e.g. shifting coal to gas-based DRI), recycling more steel and deploying innovative processes. These measures lead to a reduction of almost 2 Gt of $CO_2$ emissions per year by 2050 in the *ETP* 2DS compared to the *ETP* 6DS (baseline scenario).

This mitigation potential is to some extent based on the more effective use of hydrogen-containing off-gases – using them for reduction purposes rather than as simple fuels. In some cases, integrating the use of these off-gases in the iron ore reduction process coincides with oxygen-rich conditions, which in turn facilitates the implementation of carbon capture. Hence there is a double mitigation effect related to the implementation of these alternative processes, resulting from lower energy requirements, as fossil-based reducing agents are displaced, and from direct $CO_2$ sequestration.

Under the *ETP* 2DS, a greater penetration of natural gas-based DRI compared to the 6DS (11% more) enables emission savings of around 95 $MtCO_2$ per year by 2050. In the case of DRI, a reducing gas that contains the hydrogen needed to reduce the iron ore is typically produced on site, either from natural gas via SMR or from coal gasification.

In the post-2030 time frame, the deployment of innovative processes, which to some extent use hydrogen-containing gases as reducing agents, leads to 624 $MtCO_2$ of annual direct emission reductions by 2050 within the *ETP* 2DS. These emission reductions also include those resulting from CCS, and build on the assumption that successful demonstration is achieved on a commercial scale.

In addition to the above-mentioned measures included within the *ETP* 2DS, other mitigation options related to hydrogen technologies are feasible in the steel industry. These comprise the direct use of low-carbon footprint hydrogen or the wider deployment of processes to recycle hydrogen-containing gases.

For DRI processes, the hydrogen-containing reducing gases could be based on hydrogen with a low-carbon footprint, if it was available at competitive costs. A further 60 $MtCO_2$ emissions per year could be mitigated if the estimated 132 $GNm^3$ of hydrogen required for DRI processes in 2050 in the 2DS were decarbonised (a minimum carbon content in the reducing gas is needed to produce crude steel).

If, by 2025, commercial-scale demonstration was successfully achieved, and all blast furnaces were equipped with top gas recovery systems to recover and recycle the hydrogen-containing blast furnace gas after $CO_2$ separation, almost 370 $MtCO_2$ per year could be saved (0.3 $tCO_2$ per tonne of pig iron). This only takes account of the lower consumption of coke in the blast furnace, and ignores the possible benefits of integrating carbon capture.

## Refining industry

Even under ambitious climate scenarios such as the *ETP* 2DS high $H_2$, high energy density liquid fuels for transport will remain in demand. By 2050, petroleum-based fuels could still account for as much as 60% of total transport fuel demand on a global scale, with the market share of all liquid fuels, including biofuels, standing at around 80%. These high shares are largely due to the need for energy-dense liquid fuels in road freight, air and shipping, and also reflect the fact that alternative vehicles using hydrogen or electricity have much higher efficiencies, thus reducing their share of total transport energy use.

As all liquid fuels require hydrogen during the production process, its decarbonisation can have a significant carbon mitigation impact. Around 2% of the energy content of the final petroleum product is needed in the form of hydrogen during the refining processes (disregarding the fact that hydrogen demand depends on the ratio of gasoline production to distillate, the crude oil quality and many other parameters). Replacing fossil hydrogen with low-carbon footprint hydrogen, e.g. from methane reformation with CCS, could lead to $CO_2$ emission reductions of some 100 $MtCO_2$ per year by 2050.

## Chemical industry

Hydrogen is used as a feedstock in the synthesis of high-demand chemicals such as ammonia and methanol. The fossil-based steam-reforming process used for hydrogen generation is one of the largest energy-consuming steps in the synthesis of these chemical products. Although shifting hydrogen production from fossil to renewable-based routes increases the energy intensity of the process, it still is an attractive carbon mitigation option. A 30% replacement of fossil-derived hydrogen by renewable alternatives by 2050 could save emissions of 30 $MtCO_2$ per year in the chemical industry sector (IEA, 2013).

## Synergies between energy sectors

Most importantly, the use of hydrogen allows for the cross-sectoral integration of low value, surplus renewable electricity in energy demand sectors such as transport and industry. This enables the further decarbonisation of these sectors while unlocking new sources of system flexibility in the power sector at the same time.

During the very early phase of FCEV market introduction, hydrogen demand will need to be covered by existing generation capacity or by by-product hydrogen from the chemical and steel industry, if physical properties such as hydrogen concentration, pressure and purity allow for economically viable conditioning to make the hydrogen quality acceptable for use in PEMFCs.

Although SMR capacity at existing refineries might not provide the significant additional capacity necessary to supply hydrogen during the upscaling of the FCEV fleet, the need for future supplies of hydrogen for transport can be taken into account when adding new SMR capacity to existing or new refineries. Investment in slightly over-dimensioned SMR capacity might be attractive in return for potential future revenues from the sale of the additional hydrogen production as transport fuel.

As the increase in commercial demand for hydrogen with a low-carbon footprint from existing applications (such as refining or steel production) and from emerging applications occurs in certain clusters or regions, the low-carbon price premium for hydrogen from CCS-equipped plants can be shared. Furthermore, multiple sources of demand might enable arbitrage and management of hydrogen production capacity in the face of variable demand. This can raise capacity factors and competitiveness and can improve the business case for poly-generation plants, such as IGCC plants that balance the production of low-carbon hydrogen for electricity generation with the supply of hydrogen for transport, industry and electricity storage infrastructure.

Large numbers of FCEVs in the transport sector will have an impact on the cost of PEM fuel cell and possibly also PEM electrolyser stacks. This might even be necessary to achieve the reductions in the cost of PEM electrolysers envisaged in the "Vision", as the market for PEM electrolysers might on its own be insufficient to realise the required economies of scale.

### Box 9: Electrolysers in the control power market

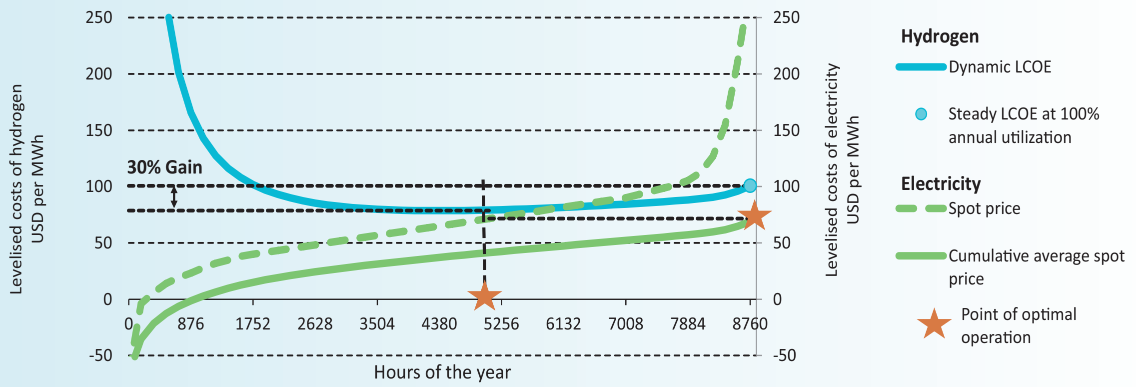
PEM electrolysers are very flexible with respect to ramp-up and load range – cold start to full power is possible in less than 10 seconds and the dynamic range almost covers the entire scale from 0% to 100% load, with loads of up to 300% possible over short times. The easy start and stop procedures, without the need to purge inert gases or for preheating, further increase operational flexibility and reduce idle power consumption. Additionally, transient operation is not linked to faster degradation.

This behaviour enables PEM electrolysers to be operated in a dynamic way and to use arbitrage effects on the electricity spot market. This can significantly reduce the LCOE of hydrogen generation. When using electricity for electrolysis along the increasing cumulative average spot price, together with the respective annual utilisation rate, an optimal annual load factor and threshold price can be determined, up to which electricity should be bought on the spot market in order to minimise the LCOE of hydrogen generation (Figure 28).

In that illustrative example, buying electricity at up to USD 72 per MWh, and therefore allowing the electrolyser to be operated for more than 5 000 hours of the year (i.e. 56% annual load factor), would reduce the LCOE of hydrogen generation by almost 30% compared to 100% utilisation of the electrolyser at an average annual spot market electricity price of USD 69 per MWh.

If the electrolyser was able to participate in the primary control power market, where providing negative controlling capacity is remunerated, hydrogen generation costs could be further reduced, while providing ancillary services to the power system. The cost of hydrogen could be reduced even more if by-product oxygen was sold.

## Figure 28: Electricity price arbitrage and hydrogen generation costs




***KEY POINT: A more dynamic use of the electrolyser with optimised operation with respect to input electricity costs and annual utilisation rate can significantly reduce LCOE of hydrogen generation.***

## Parameters of key technologies today and in the future as used in the model

### Table 15: Parameters used in the model for stationary hydrogen generation and conversion technologies as well as for energy storage and VRE integration systems today and in the future

| | | | Hydrogen generation and conversion | | | | | | | | Energy storage and VRE integration | | | | | | | Benchmark |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Unit | Alkaline electrolyser | PEM electrolyser | NG SMR | NG SMR with CCS | Coal CCS | Biomass gasification | Alkaline FC | PEM FC | $H_2$ PtP PEM/PEM | $H_2$ PtP ALK/PEM | $H_2$ PtP PEM/OCGT | $H_2$ PtG PEM HENG | $H_2$ PtG PEM methan. | PHS | CAES | OCGT |
| Today | Efficiency | - | 74% | 73% | 77% | 70% | 56% | 50% | 50% | 43% | 29% | 29% | 26% | 73% | 58% | 80% | 60% | 39% |
| | Life time | hours or years | 75 000 | 40 000 | 30 | 30 | 30 | 30 | 7 000 | 60 000 | 40 000 | 60 000 | 40 000 | 40 000 | 40 000 | 50 | 30 | 30 |
| | Investment cost conversion | USD/kW | 1 150 | 2 600 | 550 | 1 370 | 1 670 | 4 930 | 700 | 3 200 | 5 800 | 4 350 | 3 230 | 2 850 | 4 090 | 1 500 | 1 000 | 500 |
| | Investment cost storage | USD/kWh | - | - | - | - | - | - | - | - | 9 | 9 | 9 | - | - | 50 | 30 | - |
| | Fixed O&M | - | 5% | 5% | 3% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 3% | 5% | 3% |
| 2030 | Efficiency | - | 75% | 82% | 82% | 73% | 57% | 50% | 50% | 54% | 42% | 38% | 35% | 82% | 67% | 80% | 75% | 45% |
| | Life time | hours or years | 95 000 | 75 000 | 30 | 30 | 30 | 30 | 20 000 | 80 000 | 75 000 | 75 000 | 75 000 | 75 000 | 75 000 | 50 | 30 | 30 |
| | Investment cost conversion | USD/kWh | 870 | 800 | 440 | 700 | 1 280 | 1 320 | 450 | 830 | 1 620 | 1 700 | 1 420 | 1 050 | 2 280 | 1 500 | 800 | 500 |
| | Investment cost storage | USD/kWh | - | - | - | - | - | - | - | - | 1 | 1 | 1 | - | - | 50 | 15 | - |
| | Fixed O&M | - | 5% | 5% | 3% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 3% | 5% | 3% |

| | | | Hydrogen generation and conversion | | | | | | | | Energy storage and VRE integration | | | | | | | Benchmark |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Unit | Alkaline electrolyser | PEM electrolyser | NG SMR | NG SMR with CCS | Coal CCS | Biomass gasification | Alkaline FC | PEM FC | $H_2$ PtP PEM/PEM | $H_2$ PtP ALK/PEM | $H_2$ PtP PEM/OCGT | $H_2$ PtG PEM HENG | $H_2$ PtG PEM methan. | PHS | CAES | OCGT |
| 2050 | Efficiency | - | 78% | 86% | 86% | 77% | 60% | 53% | 53% | 57% | 44% | 40% | 37% | 86% | 71% | 80% | 79% | 47% |
| | Life time | hours or years | 95 000 | 75 000 | 30 | 30 | 30 | 30 | 20 000 | 80 000 | 75 000 | 75 000 | 75 000 | 75 000 | 75 000 | 50 | 30 | 30 |
| | Investment cost conversion | USD/kWh | 700 | 640 | 420 | 670 | 1 220 | 1 250 | 360 | 660 | 1 300 | 1 360 | 1 140 | 840 | 1 820 | 1 500 | 760 | 500 |
| | Investment cost storage | USD/kWh | - | - | - | - | - | - | - | - | 1 | 1 | 1 | - | - | 50 | 15 | - |
| | Fixed O&M | - | 5% | 5% | 3% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 5% | 3% | 5% | 3% |

Notes: O&M = operation and maintenance; PtG = power-to-gas; PtP = power-to-power.

Sources: IEA data; Bünger, et al. (2014), *Power-to-Gas (PtG) in Transport - Status Quo and Perspectives for Development*; Decourt et al. (2014), *Hydrogen-Based Energy Conversion, More Than Storage: System Flexibility*; Dodds and McDowall (2012), *A Review of Hydrogen Production Technologies for Energy System Models*; ETSAP (2014), Hydrogen Production and Distribution; FCH-JU (2014), *Development of Water Electrolysis in the European Union*, Fuel Cells and Hydrogen Joint Undertaking; Giner Inc. (2013), "PEM electrolyser incorporating an advanced low-cost membrane", 2013 Hydrogen Program Annual Merit Review Meeting; Hydrogen Implementing Agreement Task 25 (2009), *Alkaline Electrolysis*; NETL (2013), *Carbon Dioxide Transport and Storage Costs in NETL Studies*; NETL (2010), *Production of High Purity Hydrogen from Domestic Coal: Assessing the Techno-Economic Impact of Emerging Technologies*; NREL (2010), NREL (2009a), "Scenario development and analysis of hydrogen as a large-scale energy storage medium", RMEL Meeting; NREL (2009b), *Scenario Development and Analysis of Hydrogen as a Large-Scale Energy Storage Medium*; Saur (2008), *Wind-To-Hydrogen Project: Electrolyzer Capital Cost Study*; Stolzenburg et al. (2014), *Integration von Wind-Wasserstoff-Systemen in das Energiesystem - Abschlussbericht*; Schaber, Steinke and Hamacher, (2013) "Managing temporary oversupply from renewables efficiently: electricity storage versus energy sector coupling in Germany", International Energy Workshop, Paris; US DOE (2014b), *Hydrogen and Fuel Cells Program Record*.

# Hydrogen technology development: Actions and milestones

Technologies using low-carbon footprint hydrogen can be valuable in various end-use applications, notably in transport, but also for VRE integration. They are particularly beneficial if low-carbon energy needs to be stored, either in large quantities or under space and weight restrictions in mobile applications. Synergies between hydrogen end-use demand and VRE integration can unlock the carbon emission mitigation potential of otherwise-curtailed low-carbon electricity. In combination with CCS, low-carbon footprint hydrogen can also enable the use of low-cost fossil resources in the transport sector.

The following section provides actions and milestones together with indicative timelines, which have been developed with experts to foster the deployment of hydrogen technologies in the future. Overarching actions and milestones have been identified, which are followed by technology- or application-specific development pathways, based on metrics such as cost and efficiency targets, which have been used to define the "Vision".

## Data assessment and model development

| ***This roadmap recommends the following actions*** | | ***Time frame*** |
|---|---|---|
| Development of appropriate modelling tools | Develop modelling tools that allow the investigation of problems at the nexus between long-term and short-term optimisation of the energy system. Incorporate high granularity with respect to time and area in inter-sectoral energy system optimisation modelling environments. Investigate the impact of low utilisation rates in hydrogen refuelling infrastructure on hydrogen costs in the transport sector. | 2015-18 |
| Address data gaps | Build a comprehensive and consistent dataset with high spatial resolution, including regional resource endowments, renewable energy potential, existing and planned energy T&D networks, and geological formations suitable for hydrogen and carbon storage. | 2015-18 |
| Support R&D for system integration projects | Support R&D projects that increase the understanding of the interactions between different energy sectors, and which help to quantify benefits and challenges of system integration beyond energy flows, including questions relating to information flows, system controllability and robustness, as well as data security aspects. | 2015-18 |
| Support co-ordination between relevant actors | Support initiatives to bring together relevant actors from different parts of the energy system to co-ordinate technology development and market introduction scenarios. | 2015-18 |

More detailed modelling tools are needed at a national and international level to quantify, in robust terms, the value of system integration against a background of mitigating climate change and the need to provide access to secure and economic energy. These energy system optimisation tools need to be: 1) integrated, which means that all energy sectors (supply, transport, building and industry) are optimised at the same time; 2) granular with respect to temporal and spatial resolution; and 3) capable of capturing long-term and short-term decision-making problems. Sectoral integration is necessary to correctly represent the costs and benefits of possible mitigation measures among the whole energy system, and to identify optimal energy pathways across energy sectors. Temporal and spatial granularity is needed to provide realistic results for energy demand and supply, as well as to achieve a more robust quantification of the need to shift energy over time and space. For the latter, it is crucial to improve representation of energy T&D networks within modelling frameworks. A broader inclusion of short-term operational aspects in energy system optimisation is needed to better anticipate the use of all flexibility options within the energy system, according to their particular costs and benefits.

# Technology development

## Electrolysers

| *This roadmap recommends the following actions* | | *Time frame* |
|---|---|---|
| Electrolysers in general | Optimise the technology with a focus on cost reduction. Key areas of development comprise increased operational flexibility by improving ramp-up rates, start times and stand-by energy use. Draw upon the modularity of electrolysers and the respective flexibility of power capacity. | Complete by 2020-30 |
| PEM electrolysers | Reduce cost to USD 800 per kW through optimised manufacturing, more resistant polymer membranes and reduced noble metal content. Increase efficiency to more than 80% (HHV). Increase lifetime to at least 50 000 hours. Increase stack capacity to multiple MW. Increase total system capacity to the 100 MW scale. Achieve ramp-up rates to comply with the primary control power market. | Complete by 2025-30 |
| Alkaline electrolysers | Reduce investment cost to below USD 900 per kW. Increase efficiency to more than 75% (HHV). Increase current density through higher operating temperature and pressure. Reduce O&M costs. Increase operational flexibility through reduction in minimal load. Increase operating pressure to minimise subsequent need to pressurise the hydrogen gas. | Complete by 2025-30 |
| SO electrolysers | Prove commercial scale. Increase lifetime to at least 20 000 hours at degradation rates below 8% per year. Achieve a minimum operational flexibility to respond to future power market requirements. | Complete by 2025-30 |

Electrolysers could be a pivotal technology for achieving a wider deployment of low-carbon footprint hydrogen in the energy system. They can help to establish new links between the power sector and transport, buildings and industry by enabling new interconnections between the power grid, the natural gas network and the transport fuel infrastructure. Electrolysers can unlock the potential of hydrogen technologies to contribute to overall energy system flexibility. The generation of renewable hydrogen using electrolysers will be dependent on low-cost, renewable electricity with constrained annual availability. It is therefore particularly important to focus on reducing investment cost to allow for capital recovery under restricted annual full-load hours. Viable future business models need to be based on benefit stacking: the value of all possible by-products needs to be realised. One option is to use electrolysers as a primary control power to provide ancillary services beyond the sole generation of hydrogen.

## Fuel cells

| *This roadmap recommends the following actions* | | *Time frame* |
|---|---|---|
| Fuel cells in general | Optimise both capital costs and efficiency. Efficiency is a key parameter for stationary applications. | Complete by 2025 |
| PEMFCs, mobile applications | Reduce real-world manufacturing costs to below USD 80 per kW through optimised manufacturing and reduced need for precious metal, while keeping lifetime to at least 5 000 hours. Reduce sensitivity to hydrogen impurities. | Complete by 2025 |
| PEMFCs, stationary applications | Reduce investment cost to below USD 800 per kW by reducing both the cost of the stack and the cost of balance of plant. Increase system efficiencies to at least 50%. Increase lifetime to above 80 000 hours. Reduce sensitivity to hydrogen impurities and prove feasibility at large stack capacities. Achieve megawatt scale. | Complete by 2025-30 |
| Alkaline fuel cells | Increase technical lifetime to more than 10 000 hours. | Complete by 2025-30 |
| SOFCs | Increase cell lifetimes under real world conditions at acceptable degradation to more than 50 000 hours. Improve operational flexibility. Reduce investment costs to below USD 2 000 per kW. | Complete by 2025-35 |

Fuel cells are a key technology to efficiently use hydrogen as a high value energy carrier, especially where small and medium-sized power outputs are required. Unlike for electrolysers, the efficiency of low-temperature fuel cells remains rather low and needs to be improved. A better understanding of dynamic degradation processes of the catalyst in PEMFCs is needed to achieve high efficiencies over the entire lifetime. While high-temperature fuel cells already show promising efficiencies, current lifetime and cost levels impede commercial application.

The focus of technology development depends on the application: the focus for stationary fuel cells is increasing efficiency and ensuring utilisation of waste heat; the focus for mobile applications is on cost reduction and increased lifetime.

Large-scale manufacturing processes are needed to unlock the potential for cost reductions. In PEMFCs, the membrane electrode assembly (MEA) accounts for around 30% of the total system cost (Decourt et al., 2014). With automated manufacturing, MEA costs are reported to decrease significantly. It needs to be proven in practice whether cost reductions in PEMFC manufacturing can spill over into PEM electrolyser production.

## Hydrogen storage

| *This roadmap recommends the following actions* | | *Time frame* |
|---|---|---|
| Underground hydrogen storage | Establish national inventories of underground caverns suitable for hydrogen storage. Develop demonstration projects for hydrogen storage in salt caverns and prove feasibility to reduce investment costs for storage to USD 1 per kWh. Prove the feasibility of hydrogen storage in depleted oil and gas fields as well as aquifers. | Complete by 2025-35 |
| Pressurised tanks | Reduce material costs for high-pressure tanks on board FCEVs to at least USD 15 per kWh. | Complete by 2025 |
| Cryogenic storage and liquefaction of hydrogen | Improve the efficiency of the liquefaction process to reduce energy losses to below 30%. Reduce boil-off through improved insulation of the vessel as well as increased pressure levels. | Complete by 2030-35 |
| Metal hydrides and carbon nano-structures | Ensure continued R&D funding to further explore the potential application of solid hydrogen storage options. | 2015 onwards |

While medium-sized hydrogen storage using pressurised steel vessels is a mature technology, other small- and large-scale hydrogen storage options still need further development. In the case of on-board hydrogen storage for FCEVs, the 70 MPa high-pressure tanks are likely to be a major cost factor in the future. Unlike for the fuel cell stack, the costs of the tank are dominated by material costs rather than manufacturing costs.

In the case of large-scale hydrogen storage, in the near term the focus needs to be on improving understanding of the geographically available storage potential. Although salt caverns might be superior from a technological point of view, alternatives using depleted oil and gas reservoirs, as well as aquifer formations, need to be further investigated as options for storage potential. These alternatives might be more useful due to their geographical distribution and compatibility with existing infrastructure.

Options for combining applications need to be investigated and demonstrated in the near term to facilitate large-scale, long-term energy storage, in order to increase annual full-load hours of system components. So-called bi- or even tri-generation applications, producing hydrogen for transport in addition to generating power and, in the case of tri-generation, also heat, can be the key to achieving necessary asset utilisation. Participation in different energy markets might be a prerequisite to making hydrogen-based energy storage technologies economically feasible.

## FCEVs

| *This roadmap recommends the following actions* | | *Time frame* |
|---|---|---|
| Investment costs | Achieve a price premium of 15% or less compared to hybridised ICE vehicles at higher volume annual production rates. | Complete by 2025 |
| On-board hydrogen storage | Reduce the volume and the weight of the hydrogen tank. Reduce specific costs to at least below USD 15 per kWh. | Complete by 2025 |
| Fuel economy and range | Achieve an on-road fuel efficiency of 0.8 kg of hydrogen per 100 km. | Complete by 2025 |
| | Improve on-road fuel efficiency to up 0.6 kg of hydrogen per 100 km to reduce the size of the tank while achieving at least 500 km range. | Complete by 2035 |
| Refuelling | Establish an international standard for refuelling pressure and shape of the nozzle. | Complete by 2020 |

The next ten years will be crucial for demonstrating the large-scale mobility potential of FCEVs. Although some manufacturers announced the introduction of commercially available FCEVs during 2015, it will be necessary to sell the first tens of thousands of FCEVs to technophile "first movers" around the globe to learn about consumer acceptance and technology behaviour under real-life conditions.

Vehicle cost reductions are crucial to achieving such an ambitious target. For success beyond the large-scale technology demonstration phase, the purchase price of FCEVs should not be much higher than 15% above that for conventional hybrid cars, taking into account the higher cost of the fuel. To reduce the cost of the vehicle as a whole, each subsystem needs to contribute, with the actual fuel cell system being only one part of that. Being able to equip otherwise-conventional vehicles with a fuel cell powertrain and hydrogen storage will be a major step towards larger-scale commercialisation.

## Hydrogen T&D and retail infrastructure

| *This roadmap recommends the following actions* | | *Time frame* |
|---|---|---|
| Tractor-trailer combinations | Increase the capacity of tube trailers for transport of gaseous hydrogen to above 900 kg. Increase the pressure to reduce the need for compression work at the station. | Complete by 2025 |
| Retail station | Define optimal hydrogen station layout with respect to hydrogen phase (gaseous vs. liquefied), size, pressure and compression scheme, taking into account region-specific characteristics of hydrogen generation pathways. Define standardised refuelling pressures. Consider proposals for modular or mobile hydrogen stations to reduce under-utilisation during FCEV market introduction and scale-up. Reduce station area footprint. Design user-friendly and standardised dispensers. Reduce investment costs to below USD 1 million for small stations dispensing in the region of 200 kg of hydrogen per day. | Complete by 2020-25 |
| Compressor | Eliminate uncertainties and focus on decreasing costs for compression. Achieve investment costs of USD 300 per kW of hydrogen throughput and less for an 88 MPa compressor. Develop scenarios to determine optimal compression levels throughout each stage, from hydrogen generation to retail at the station. | Complete by 2020-25 |

The build-up to a minimum hydrogen T&D and retail network will be the main barrier to the widespread use of FCEVs in transport. Large-scale demonstration programmes, initially bringing several thousand FCEVs on the road, must be supported by hydrogen refuelling networks providing coverage in selected core regions. Furthermore, these demonstration regions need to be connected via corridors to enable "first movers" to use their FCEV on long-distance trips, and should be developed based on existing hydrogen infrastructure. Various clusters are currently planned in California, Germany, the United Kingdom, France, the Netherlands, Japan and Korea.

Certain key parameters, such as vehicle on-board storage pressure and the shape of the refuelling nozzle, need to converge in the next decade to facilitate infrastructure development. Furthermore, station layouts that allow for modular expansion of refuelling capacity alongside demand need to be developed, in order to minimise under-utilisation. The set-up of this entirely new energy infrastructure will not be based on a single approach, but all options, including vehicle fleets and public transport, need to be integrated to create sufficient hydrogen demand around the initial T&D clusters.

Finally, scaling up from clustered hydrogen retailing to national and regional coverage will demand major investment supported by government programmes, and will require consensus among a great number of stakeholders, from the oil and gas industry, utilities and power grid providers, car manufacturers, and local, regional and national authorities. Achieving this common understanding of future development might well be the most serious hurdle to overcome.

## $CO_2$ capture and storage

| *This roadmap recommends the following actions* | | *Time frame* |
|---|---|---|
| $CO_2$ capture from SMRs | Raise the number of operating SMRs equipped with large-scale $CO_2$ capture (e.g. 100 000 tonnes of $CO_2$ per year [$tCO_2$/yr] and above) to five worldwide. Public funding should support the use of capture technologies that promise lower costs and higher capture rates, such as cryogenics, vacuum pressure swing adsorption (VPSA) and membranes. | Complete by 2020-25 |
| Poly-generation with CCS | Demonstration of commercial poly-generation of low-carbon hydrogen and other commodities (electricity, urea, methanol) from coal conversion combined with CCS in five large-scale projects worldwide. | Complete by 2020-25 |
| $CO_2$ capture and supply | Reduce the cost of $CO_2$ capture from flue gases and other sources identified as potential $CO_2$ suppliers for power-to-gas and power-to-liquids processes to USD 15 to USD 50 per tonne of $CO_2$. Suppliers could include biogas upgraders, bioethanol mills, steel plants, refineries, chemical plants, power plants or direct air capture (depending on timing of anticipated need). | Complete by 2025-35 |
| $CO_2$ storage | Implement policies that encourage storage exploration and characterisation, and development of $CO_2$ storage resources in countries where hydrogen production from fossil fuels with CCS is a cost-effective option. To manage multiple emission sources, public and private investment in strategic $CO_2$ storage assets needs to be increased from today's low levels in most countries, in parallel with stimulating the emergence of viable $CO_2$ storage service providers and establishing governance frameworks that ensure safe and effective storage. | Complete by 2020-30 |

While $CO_2$ capture from SMR currently operates at scales of 1 million $tCO_2$/yr per plant, or 1.2 billion standard cubic feet per day (BSCFD) of hydrogen, further action is needed to make the full CCS chain a financeable proposition for climate change mitigation. The cost of $CO_2$ capture from SMR can be further reduced. The sale of low-carbon hydrogen from coal, alongside products destined for other commodity markets using poly-generation, needs to be demonstrated. Above all, however, incentivising permanent $CO_2$ storage is the key to unlocking the cost advantage presented by hydrogen production coupled with CCS. The IEA *Technology Roadmap for Carbon Capture and Storage* (2013) recommended five key actions for $CO_2$ storage in the near term. These relate primarily to policies and regulations that encourage $CO_2$ storage resources to be characterised and made commercially available. Ensuring safe and effective storage, sound management of natural resources, and public consultation in line with best practice are also essential items.

# Policy, regulatory framework and finance: Actions and milestones

Strong policies are needed if hydrogen as an energy carrier is to play a major role in a future low-carbon energy system. The large-scale deployment of hydrogen is linked to the introduction of entirely new technologies, both on the energy supply side and the demand side, requiring the establishment of a new energy T&D and retail system in parallel. The simultaneous development of such complex tasks will require proactive intervention and co-ordination.

This roadmap highlights several specific challenges for policymakers. These include the reduction of emissions from road transport, the facilitation of high levels of variable renewable electricity and the creation of markets for low-carbon industrial production based on increased use of hydrogen and fuel cell technologies. Sound policy approaches will be needed to stimulate effective competition between technological solutions, including but not limited to the use of hydrogen and fuel cells. In addition to internalising the environmental and social costs of GHG emissions, policy can provide directed support to promising technologies to reduce costs, improve performance and enable early market introduction. Preferably, such measures should be time-limited and encourage low-carbon options to compete on their merits.

Governments can act as catalysts to speed up developments by providing support in the form of RD&D funding, access to attractive financing programmes, and the necessary regulatory and policy framework. The latter point is especially important as governments need to take the lead on providing a stable investment environment, clearly formulating long-term targets, especially with respect to energy use and climate change.

Mobilising private capital is a prerequisite for the large scale deployment of hydrogen and fuel cell technology. During the past decade, several initiatives and public-private partnerships have been created to co-ordinate action between stakeholders and to secure funding (Table 16). For example, to develop the hydrogen generation and refuelling infrastructure necessary for the successful introduction of FCEVs, car manufacturers, fuel cell and electrolyser producers, oil, gas and power suppliers, as well as transport service providers, have created common initiatives to try to manage the investment risk. Ultimately, the success of these initiatives will be measured by their ability to achieve binding agreements among the different stakeholders to tackle the "chicken and egg" problem. Globally, significant annual funding, in the order of several hundred million US dollars, is being spent on hydrogen and fuel cell technologies as well as related infrastructure development[13].

13. For comparison, in 2012 about USD 1 billion has been spent by governments on solar and CSP RD&D, and around USD 1.5 billion was allocated to biofuels.

## Table 16: Initiatives and public-private partnerships to promote hydrogen and fuel cell technologies

| *Region* | *Exemple* |
|---|---|
| Europe | • Fuel Cell and Hydrogen Joint Undertaking (FCH-JU, EU)<br>• Nationale Organisation Wasserstoff- und Brennstoffzellentechnologie (NOW GmbH, Germany)<br>• Clean Energy Partnership (CEP, Germany)<br>• Mobilité Hydrogène (France)<br>• Scandinavian $H_2$ Highway Partnership (SHHP, Scandinavia)<br>• HyNor (Norway)<br>• Hydrogen Sweden (formerly HyFuture, Sweden)<br>• UK $H_2$ Mobility (United Kingdom) |
| North America | • CaFCP,California)<br>• $H_2$USA (United States)<br>• Canadian Hydrogen and Fuel Cell Association (CHFCA, Canada) |
| Japan | • The Research Association of Hydrogen Supply/Utilization Technology (HySUT)<br>• Fuel Cell Commercialisation Conference of Japan (FCCJ) |

## Hydrogen in transport

| *This roadmap recommends the following actions* | | | |
|---|---|---|---|
| ***Policy*** | ***Target group*** | ***Technology neutral*** | ***Time frame*** |
| $CO_2$-based vehicle taxation | Consumers | ✓ | Implement by 2015-20 |
| Feebate schemes | Consumers | ✓ | |
| Labelling schemes | Consumers | ✓ | |
| Vehicle "perks" – free use of public parking, use of high occupancy vehicle lanes, use of bus lanes, exemption from road tolls | Consumer | ✓ | |
| Fuel economy standards | Car manufacturers | ✓ | |
| Zero-emission vehicle regulation | Car manufacturers | ✓ | |
| Low-carbon/renewable fuel regulation | Fuel suppliers | ✓ | |
| Direct vehicle purchase subsidies | Consumers | | |
| Vehicle purchase and fuel tax exemption | Consumers | | |
| Subsidies for $H_2$ infrastructure | Fuel suppliers | | |

Policy measures to support the large-scale application of FCEVs in transport can be categorised by the target group they address, e.g. the consumer, the car manufacturers or the fuel suppliers. They can furthermore be distinguished as technology-specific and technology-neutral support instruments.

A whole range of technology-neutral policies exist that apply to the consumer and which can be beneficial to the introduction of FCEVs. These policies comprise annual vehicle taxation schemes (e.g. in Germany) based on vehicle $CO_2$ emissions, or the introduction of feebate schemes for vehicle registration taxes (e.g. in France). As hydrogen vehicles would certainly fall within the category of low-emission vehicles, they would benefit from lower taxation or higher rebates. Together with labelling schemes clearly stating fuel economy and $CO_2$ emissions (based on region-specific emission factors for hydrogen and electricity) and other soft measures to incentivise low-emission vehicles, such as free use of public parking spaces, the use of bus lanes and high occupancy vehicle lanes or the free use of toll roads, these technology-neutral measures can already contribute to attracting consumer interest in FCEVs.

Technology-neutral policies such as demanding, long-term fuel economy standards can be a strong incentive to car manufacturers to introduce low-emission vehicles, as they can significantly contribute to achieving corporate average fuel economy targets. The same is true for the introduction of zero-emission vehicle quotas for government fleets, as formulated for example in the Californian ZEV Action Plan (Governor's Interagency Working Group on Zero-emission Vehicles, 2013).

On the fuel supply side, incentivising the introduction of low-carbon fuels can be broadened to hydrogen. If, for example, hydrogen were to qualify as a biofuel under the US Renewable Fuel Standard 2 (RFS 2), a strong incentive to scale up hydrogen generation capacity would be provided. Similarly, the EU Fuel Quality Directive could incentivise the deployment of low-carbon hydrogen throughout the production process of conventional petroleum fuels.

Due to the complexity of the value chain, coordinated policy support may be needed simultaneously in a number of areas. Alongside technology-specific support for FCEVs, the scale up of hydrogen generation, T&D and retail infrastructure will be necessary for wider market adoption.

In Europe, the TEN-T programme was established to support the construction and upgrade of transport infrastructure across the European Union. Part of this program is the HIT (Hydrogen Infrastructure for Transport) project, aiming at establishing a basic network of European hydrogen refuelling infrastructure to enable large distance travel using FCEVs. The recently adopted "Directive on the deployment of alternative fuels infrastructure" acknowledges the need for the built-up of hydrogen refuelling infrastructure as a prerequisite for FCEV deployment. It furthermore concludes that by end 2025 an "appropriate number" of hydrogen refuelling stations needs to be in place within those Members States which adopted the use of hydrogen for road transport as one of their national polices.

In addition to this, FCEVs and hydrogen will need to be exempted from taxation of vehicle registration, vehicle ownership and purchase of fuel, to close the gap in TCD with conventional cars. Depending on the pace of FCEV market uptake, these tax exemptions might be necessary for a time period of at least 10 to 15 years after FCEV market introduction, and should be closely monitored and regularly adjusted to prevent over- or underspending.

Additionally, direct subsidies to reduce the remaining gap in $TCD_{tax}$ may be necessary for an extended time period, if cost parity with conventional technology is envisaged. These direct subsidies need to be split among consumers, car manufacturers and fuel suppliers in a way that the market is stimulated and the investment risk for both car manufacturers and fuel suppliers is minimised. This might involve direct subsidies to consumers when buying an FCEV, government support to car manufacturers to scale up FCEV manufacturing, and government support to the fuel suppliers to help set up an initial refuelling infrastructure. All kinds of subsidies must be thoroughly monitored and adapted to market conditions in order to prevent over- or underspending. As highlighted in the "Vision", TCD can be an effective measure to evaluate and adjust levels for direct subsidies in transport on a regular basis. Particularly for technologies expected to have high learning rates, determining the right amount of subsidies can save resources.

## Hydrogen in stationary applications

| *This roadmap recommends the following actions* | | | |
|---|---|---|---|
| ***Policy*** | ***Target group*** | ***Technology neutral*** | ***Time frame*** |
| Long-term emission reduction targets | - | ✓ | |
| Carbon pricing | - | ✓ | |
| Incentivise VRE operators to adopt grid integration measures | Utilities, decentralised generation | ✓ | |
| Increase price transparency for power generation and heat production | Utilities, decentralised generation, energy storage operators | ✓ | |
| Facilitate entry into energy markets | Decentralised generation, energy storage operators | ✓ | Implement by 2015-20 |
| Enable benefit-stacking for energy storage systems. | Energy storage operators | ✓ | |
| Exemption of electrolysers from renewable surcharge and grid usage fees | Utilities, energy storage operators, grid operators | | |
| Green gas certificates | Energy storage operators | | |

Similar to mobile applications, policies to incentivise hydrogen in stationary applications can be divided into technology-neutral and technology-specific measures.

As for any other low-carbon technology, the presence of long-term emission reduction targets is a prerequisite for hydrogen technology deployment. In combination with an increasing carbon price as a result of tightening emission targets, stationary hydrogen-based energy technologies can become competitive in the future if finance for RD&D is secured during the early phase of technology development.

It is necessary to incentivise not only the addition of VRE capacity, but also its integration into the power system to prevent increasing rates of curtailment and to reflect the real costs of VRE. This will foster the uptake of flexibility measures within the energy system, and thus possibly also the deployment of hydrogen-based energy storage systems.

Hydrogen technology-specific policy measures could facilitate the technology's entry into energy markets, such as the exemption of electrolysers from renewable surcharges and grid usage fees. This is justified given the fact that the potential use of electrolysers in the primary control power market would actually help to integrate otherwise-curtailed electricity from VRE, and therefore ease pressure on power grids. It will furthermore be essential to allow energy markets to qualify for benefit stacking. This basically means that hydrogen-based energy storage systems should be able to be remunerated for all ancillary services they provide to the grid.

The further development of green gas certificates can provide the option of selling low-carbon gas to consumers who are prepared to pay a price premium. This also opens up the possibility for PtG operations to sell lower carbon footprint gas to consumers, who are not physically connected to the same natural gas distribution grid.

In 2014, a new proposal for a Council Directive on calculation methods and reporting requirements pursuant the European Fuel Quality Directive (European Commission, 2014) was presented. It lays out a method for fuel suppliers to calculate the lifecycle GHG emissions associated with their products, in order to reach the 6% emission reduction target, which is due to be achieved by 2020. This, together with post-2020 plans to achieve a 60% emission reduction in transport within the European Union by 2050 (European Commission, 2011), can finally incentivise the use of low-carbon hydrogen in the refinery sector.

## The role of codes and standards

| ***This roadmap recommends the following actions*** | ***Time frame*** |
|---|---|
| Development of a methodology to include region-specific upstream emissions during fuel production within the new Worldwide harmonised Light vehicles Test Procedures (WLTP). | Implement by 2015-20 |
| Establish a performance-based global technical regulation for type approval of motor vehicles within the UN framework to ensure safety of FCEVs being comparable or superior to those of conventional PLDVs | |
| Hydrogen handling security regulation | |
| Hydrogen metering regulation | |
| Hydrogen refuelling equipment standardisation | |
| Natural gas-hydrogen blend quality and safety regulation | |
| Determination of maximum blend shares for hydrogen in natural gas by application | |

Standardisation is an important element on the way towards large-scale application of hydrogen as an energy carrier. In particular, the security regulations for FCEVs and hydrogen handling in the transport sector need to be harmonised on a global scale.

In 2014, the UN Working Party on Passive Safety submitted a "Proposal for a new Regulation on hydrogen and fuel cell vehicles (HFCVs)" (Working Party on Passive Safety, 2014) to establish uniform provisions for the type approval of FCEVs. This work needs to be finalised to allow for the sale of large volumes of FCEVs.

Currently, requirements for FCEVs are developed with reference to the WLTP, which is being developed to determine the levels of pollutants and $CO_2$ emitted by new PLDVs and light commercial vehicles in a globally harmonised way. Setting up a sound methodology to include emissions during the fuel production process is a necessary step towards measuring $CO_2$ emissions from FCEVs, BEVs and plug-in hybrids.

The harmonisation of standards for hydrogen metering at refuelling stations can help reduce the cost of developing station equipment. Establishing global standards is a matter of urgency for other hydrogen refuelling station equipment such as the dispenser, including the nozzle to connect the dispenser to the car.

To enable PtG applications, quality standards for blended natural gas need to be developed to enable safe operation of natural gas-fuelled end-use applications, as well as to allow for correct metering on an energy content basis. This is required for blending hydrogen in local distribution grids and for selling blended natural gas through transmission lines on a regional, national or even international scale. As first step, international agreement is needed on maximum blend shares acceptable for different end-use applications.

## Finance

| ***This roadmap recommends the following actions*** | ***Time frame*** |
|---|---|
| Provision of long-term low-interest loans | Implement by 2015-20 |
| Development of renewable energy grants and funds | |
| Development of green bonds | |
| Investment tax credits | |
| Long-term RD&D funding | |
| University funding, competitive awards | |

Securing finance for innovative technologies is often challenging. Both governments and financial institutions are essential to providing access to necessary funds and to incentivise investment in low-carbon energy technologies.

Government support needs to be adapted to the different phases of the innovation and deployment cycle and the right support depends on the maturity of the technology and the degree of market uptake (IEA, 2015).

For technologies at the earlier stages of the innovation cycle, such as high-temperature fuel cells and electrolysers, which need to substantially improve performance and reduce costs to achieve technical and economic viability, "technology push" mechanisms are most effective. Securing long-term RD&D funding, e.g. through research grants, is a prerequisite for successful upscaling of hydrogen and fuel cell technologies. Apart from financing research, the tendering of competitive awards can be an attractive option.

Technology innovation for post-commercialisation deployment is largely based on mobilising private investments from the industries manufacturing the technology. They will need a stable, long-term support to deployment and the provision of long-term, low-interest loans or the development of renewable energy grants and funds can help to reduce the costs of capital.

New financing mechanisms such as green bonds can also be a mean to lower the costs of capital. The first green bonds[14] were issued in 2008 by the World Bank Treasury and by July 2014, green bond issuances well exceeded USD 20 billion – twice the amount as those issued in 2013 (World Bank, 2014).

Furthermore, investment into hydrogen and fuel cell technologies qualifying as low-carbon energy technologies can also be incentivised through special tax programmes, aimed at reducing tax liabilities on corporate or income taxes of businesses and households.

14. Green bonds are fixed-income, liquid financial instruments that are used to raise funds dedicated to climate mitigation, adaptation and other environment-friendly projects (www.worldbank.org/en/topic/climatechange/brief/green-bonds-climate-finance).

In general, all financial instruments need to have transparent methodologies for deciding on the qualification of energy technologies under these programmes. In this respect, current and expected abatement costs are a useful measure to compare clean energy technologies, as they allow the costs of carbon mitigation to be directly compared.

## International collaboration

International collaboration is key to successful technology development programmes. In developed regions, replacing parallel development of work streams with co-ordinated RD&D efforts can contribute significantly to reducing timescales and optimising resources. This is especially true in times of tight public funding budgets. Platforms such as the hydrogen-related Implementing Agreements within the IEA Technology Network (e.g. Hydrogen Implementing Agreement [HIA] and Advanced Fuel Cell Implementing Agreement [AFC IA]) or the International Partnership for Hydrogen and Fuel Cells (IPHE) need to be used in an efficient manner to deepen international teamwork.

International cooperation can successfully engage emerging economies in activities that can enhance their domestic technological capability (or absorptive capacity) to deploy clean energy technologies and also to deliver clean energy innovation autonomously. Knowledge spill-over effects between developed and developing regions are necessary if hydrogen technologies are to play a significant role beyond the regions discussed in this roadmap. The results of costly learning processes need to be accessible globally. For countries such as China or India, the development of hydrogen technologies in combination with CCS could be attractive to transform abundant domestic fossil resources into low-carbon transport fuels.

## Social acceptance and safety

Effective public education will be essential to the widespread social acceptance of hydrogen technologies. Convincing the consumer that FCEVs are safe will be one of the major tasks during the early market introduction phase. Early education of all relevant stakeholders, including ambulance and fire service personnel, is critical. This can be done through continued information campaigns and, in respect of safety-related matters, through the further development of international hydrogen technology-related training programmes, such as the European HySafe project.

Furthermore, the results of FCEV crash tests (e.g. those crash tests required for the NCAP safety rating) should be disseminated through information campaigns. Adequate training of hydrogen refuelling station personnel and reassuring operation of the refuelling station equipment are preconditions to reducing security concerns.

# Conclusion: Near-term actions for stakeholders

This roadmap investigates the potential for hydrogen technologies to help achieve an emission trajectory needed to limit the long-term global average temperature rise to 2°C. It includes specific milestones that the international community can use to track the progress of hydrogen technology deployment, if hydrogen is to play a significant role as an energy carrier by 2050, as outlined in the 2DS high $H_2$. The IEA, together with governments, industry and other key stakeholders, will report regularly on this progress, and recommend adjustments to the roadmap as needed.

Recommended actions for key stakeholders are summarised below, and are presented to indicate who should take the lead in such efforts.

| *Lead stakeholder* | *This roadmap recommends the following actions* |
|---|---|
| Governments | • Push forward long-term climate targets and establish a stable policy and regulatory framework, including for example carbon pricing, feed in tariffs or renewable fuel standards to encourage fuel efficiency and low greenhouse gas emission technologies across all energy sectors.<br>• Strengthen fuel economy and $CO_2$ emission regulation as well as pollutant emission standards for road vehicles beyond the time frames and modes already covered by today's approaches.<br>• Apply monetary measures to incentivise alternative fuel vehicles, e.g. feebate systems, $CO_2$-based vehicle ownership and circulation taxation.<br>• Improve and strengthen the policy framework to address upstream emissions during fuel generation in the transport sector.<br>• Establish a power market framework, which allows for the adequate remuneration of all power system services provided by energy storage technologies.<br>• Harmonise safety codes and standards for hydrogen T&D and retail infrastructure as well as for hydrogen metering.<br>• Where regionally relevant, establish standards for natural gas quality with hydrogen blend share.<br>• Support research projects that increase understanding of the interactions between different energy sectors, and which help to quantify benefits and challenges of system integration.<br>• Support RD&D necessary to improve key hydrogen conversion technologies such as electrolysers and fuel cells.<br>• Support government involvement in demonstration projects, especially with respect to hydrogen transmission, distribution and retail infrastructure roll-out.<br>• Address potential market barriers where opportunities exist for the use of low-carbon hydrogen in industry (e.g. in refineries).<br>• Extend information campaigns and educational programs to increase awareness-raising. |
| Industry | • Identify the lowest-cost system design and manufacturing methods for fuel cells and electrolysers. Optimise lifetime and degradation and scale up system size.<br>• Demonstrate the large-scale mobility potential of FCEVs by proving on-road practicality and economics across the supply chain of FCEVs. Put the first tens of thousands of FCEVs on the road.<br>• Prove the economic feasibility and built-up hydrogen generation, T&D and retail capacity necessary to refuel several tens of thousands of FCEVs.<br>• Demonstrate hydrogen-based energy storage systems in large-scale applications.<br>• Where regionally relevant, accelerate activities directed at developing the capture and storage of $CO_2$ from fossil-derived hydrogen production into mature business activities.<br>• Bring down costs and of FC micro combined heat and power systems. |

| *Lead stakeholder* | *This roadmap recommends the following actions* |
|---|---|
| Academia | • Provide the tools to analyse the energy system, including all energy demand and energy supply sectors, with the temporal and spatial resolution necessary to adequately examine synergies between hydrogen demand, VRE integration and energy storage.<br>• Improve the data on resource availability, costs and geologic formations suitable for underground storage of gaseous energy carriers.<br>• Develop strategies to cluster hydrogen refuelling infrastructure during technology roll-out.<br>• Include and improve linkages between different energy infrastructure systems (e.g. the power grid and the natural gas grid) in national energy system models.<br>• Improve methods to quantify directly and indirectly occurring upstream GHG emissions during transport fuel generation, T&D and retail beyond the focus on carbon dioxide emissions.<br>• Determine maximum acceptable blend shares of hydrogen in natural gas to comply with different end-use specifications. |

# Abbreviations, acronyms and units of measurement

## Abbreviations and acronyms

| | |
|---|---|
| ALK | alkaline |
| BEV | battery electric vehicle |
| BF | blast furnace |
| BFG | blast furnace gas |
| BOFG | basic oxygen furnace gas |
| BOP | balance of plant |
| CAES | compressed air energy storage |
| CCGT | combined cycle gas turbine |
| CCS | carbon capture and storage |
| CNG | compressed natural gas |
| COG | coke oven gas |
| CV | commercial vehicle |
| DRI | direct reduced iron |
| EAF | electric arc furnace |
| EL | electrolyser |
| *ETP* | *Energy Technology Perspectives* |
| FC | fuel cell |
| FCEV | fuel cell electric vehicle |
| HENG | hydrogen-enriched natural gas |
| HFT | heavy freight truck |
| HHV | higher heating value |
| ICE | internal combustion engine |
| IGCC | integrated gasification combined cycle |
| LCOE | levelised cost of energy |
| $LCOH_2$ | levelised cost of hydrogen |
| LCV | light commercial vehicle |
| LHV | lower heating value |
| MCFC | molten carbonate fuel cell |
| MEA | membrane electrode assembly |
| MFT | medium freight truck |
| NG | natural gas |
| OCGT | open-cycle gas turbine |
| O&M | operation and maintenance |
| PAFC | phosphoric acid fuel cell |
| PEM | proton exchange membrane |
| PEMFC | proton exchange membrane fuel cell |
| PHEV | plug-in hybrid electric vehicle |
| PHS | pumped hydro energy storage |
| PLDV | passenger light-duty vehicle |
| PtG | power-to-gas |
| PtP | power-to-power |
| RD&D | research development and demonstration |
| SMR | steam methane reforming |
| SOFC | solid oxide fuel cell |
| SR | smelt reduction |
| T&D | transmission and distribution |
| TCD | total costs of driving |
| ULCOS | ultra-low-carbon dioxide steelmaking |
| VRE | variable renewable energy |
| WTW | well-to-wheel |

## Units of measure

| | |
|---|---|
| EJ | Exajoule |
| Gt | Gigatonne |
| Kg | Kilogramm |
| Km | Kilometre |
| kW | Kilowatt |
| Lge | Litre of gasoline equivalent |
| MPa | Megapascal |
| Mt | Megatonne |
| MW | Megawatt |
| MWh | Megawatt hour |
| TWh | Terawatt hour |

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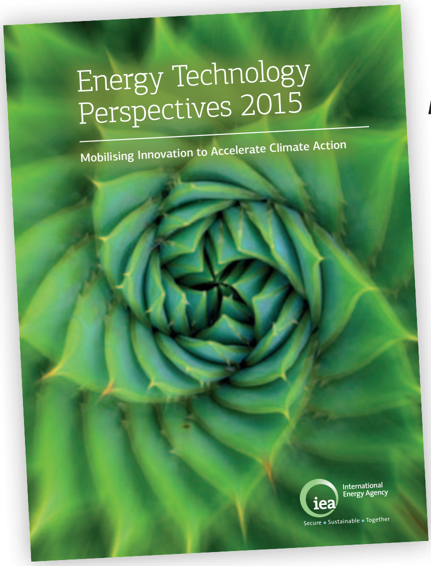


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