

Technology Roadmap Hydrogen and Fuel Cells

Technical Annex

Alexander Körner

29-Jun-15

Table of contents

Technology status today	2
Hydrogen generation and conversion.....	2
Hydrogen storage and transmission	9
Hydrogen in the iron and steel industry.....	13
Vision – Transport modelling insights	17
Annex A: Abbreviations, acronyms and units of measurement	26
Abbreviations and acronyms.....	26
Units of measure	27
Annex B: References	26

List of Figures

Figure 1 Midrex process diagram	13
Figure 2 Blast furnace with top gas recovery diagram.....	15
Figure 3 FCEV sales in the 2DS high H ₂ for EU 4, Japan and the United States until 2050.....	17
Figure 4 FCEV costs, hydrogen costs at the pump and total costs of driving for the 2DS high H ₂ for EU 4, Japan and the United States.	20
Figure 5 Total costs of driving with petroleum fuel taxes and fuel tax exemption of hydrogen for EU 4, Japan and the United States for the 2DS high H ₂	21
Figure 6 Total cumulative subsidies as a function of depreciation time and cost premium per km (of FCEVs compared with gasoline ICE cars).....	22
Figure 7 Cumulative investment costs into hydrogen generation, T&D and retail infrastructure in the 2DS high H ₂ until 2050 for EU 4, Japan and the United States.....	25

List of Tables

Table 1 Current performance of key hydrogen and fuel cell technologies.....	5
Table 2 Main technology options for hydrogen use as reducing agent in the iron and steel sector..	14
Table 3 Electric vehicle sales	17
Table 4 Techno-economic parameters of FCEVs as computed in the model for the United States...	18
Table 5 Cost of PLDVs by technology as computed in the model.....	19
Table 6 Disaggregation of urban areas.....	24

Technology status today

Hydrogen generation and conversion

Steam methane reforming (SMR)

The SMR process is based on a reaction of a mixture of methane and water steam in the presence of a catalyst (e.g. nickel). At temperatures of around 800 degree Celsius methane reacts with the hydrogen contained in water to form hydrogen gas, carbon monoxide and carbon dioxide. The carbon monoxide contained in the hydrogen-rich syngas is further transformed to carbon dioxide in the water-gas shift reactor, liberating additional hydrogen gas from water vapour. Remaining impurities are removed using pressure-swing absorbers and recycled as fuel for heat generation. The required purity of the hydrogen has great impact on costs and overall process efficiency.

SMR units can be combined with carbon capture and storage (CCS) technology. This way, around 80% of CO₂ produced during the SMR process could be captured and sequestered. Since CO₂ concentration is relatively high in the SMR exhaust gas (around 10% to 20%), the separation of the CO₂ would lead to only modest efficiency losses and increase the costs of hydrogen generation by about 20% to 30%, if applied to large-scale processes (International Energy Agency, 2007). If combined with enhanced oil recovery (EOR), the separated CO₂ could be injected in depleted oil fields to increase the deposit pressure and hence the crude oil yield.

For industrial applications, SMR units exist in sizes between 5 000 and 200 000 Nm³/hour, which translates into hourly production rates of 450 kg to 18 000 kg of hydrogen. Costs of hydrogen from SMR are highly dependent on natural gas and carbon prices. At current price levels, hydrogen is produced at costs of around USD 0.9 per kg in the United States, USD 2.2 per kg in Europe and USD 3.2 per kg in Japan¹.

Very small-scale reformation units with production rates down to 50 Nm³/h (i.e. 4.5 kg of hydrogen per hour) exist. These reformers are mostly based on the auto-thermal reformation process. With respect to hydrogen generation cost, these very small-scale gas reformer units currently operate in the same order of magnitude as today's electrolyzers. The main challenges are the reduction of reformer size and the increase of efficiency to above 75% as well as the handling of transient hydrogen demand profiles, start-up behaviour and sulphur removal.

Reformation processes are not limited to the use of natural gas. All hydrogen-rich gases can be used to produce pure hydrogen via adapted reformation processes. Once the primary energy carrier is gasified, hydrogen can be produced from other fossil primary energy carriers like coal but also from fossil feedstock like naphtha and from biomass feedstock like ethanol, sugar alcohols and less refined raw materials like cellulose and hemicellulose. The main challenge with biomass feedstock is to improve the hydrogen yield since feedstock costs are significantly higher than for fossil energy carriers. In 2011 the National Renewable Energy Laboratory (NREL) estimated the cost of hydrogen from biomass gasification to be around USD (2009) 5.40 per kg for the first large-scale hydrogen production plant, which could eventually decline to USD (2009) 2.30 to USD (2009) 3.40 per kg, depending on sensitivities like capital costs and feedstock price (NREL, 2011).

¹ 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.

Electrolysis

Electrolysis is a method to separate elements by applying a direct current to the compound material. Through electrolysis, water can be decomposed into hydrogen and oxygen.

The direct current power source is connected to two electrodes which are separated by the electrolyte. The cathode (negatively charged), anode (positively charged) and electrolyte form the electrolyser cell. The charge carrier closes the circuit between anode and cathode and, together with the electrolyte, characterises different forms of electrolysers. The electrolyte can be of different states and materials and is used to distinguish the different types. In all electrolysers, hydrogen is discharged at the cathode and oxygen is discharged at the anode.

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

All electrolysers consist out of the electrolyser stack and the “balance of plant” (BOP), which includes other systems like the inverter to convert the input electricity from alternate to direct current, water treatment (e.g. deioniser) and storage. Depending on the use of the produced hydrogen, further conditioning of the hydrogen is needed (e.g. dehydration, compression).

Electrolyser stacks consist of up to more than 100 cells. Stacks can be mounted in parallel using the same BOP infrastructure. Electrolysers are hence highly modular systems. While this makes the technology very flexible with respect to hydrogen production plant size, it also limits the effects of economies of scale, as even big electrolysers are based on identically sized cells and stacks.

Alkaline electrolysers

In alkaline electrolysers the electrolyte is potassium hydroxide solution, a highly corrosive liquid, which serves as water feedstock at the same time. Water is split at the cathode into hydrogen and hydroxide ions. The hydroxide ions pass through a membrane to the anode where they are oxidised to oxygen and water.

Alkaline electrolysers are currently the most mature and economic way to produce hydrogen from electricity, if hydrogen is produced at large quantities and at high loads. As the liquid electrolyte has to be circulated and regenerated periodically, the balance of plant is complex. Alkaline electrolysers show thermodynamic efficiencies of around 65% up to 82% (higher heating value, HHV) with rather high ramp-up and black-start times. Flexibility with respect to load is limited: minimum load should not go below 20% of nameplate capacity. Alkaline electrolysers belong to the group of low-temperature electrolysis achieving operation temperatures of 70°C to 90°C.

With investment costs of USD 850 to 1 500 per kW (depending mainly on stack size), levelised production cost of hydrogen are highly dependent on electricity prices and are somewhere around USD 5.0 (United States) to USD 6.1 (Japan) per kg of hydrogen, with today's costs of electricity between USD 94 (United States) and USD 120 (Japan) per MWh, and an assumed annual load utilisation rate of 75% (see also Figure 18 in *Technology Roadmap on Hydrogen and Fuel Cells*).

Alkaline electrolysers are currently used at industrial scale mainly to produce fertilisers from cheap electricity (Decourt, Lajoie, Debarre, & Soupa, 2014). Reported lifetimes of up to 90 000 hours are already acceptable for commercial application. Maximum stack capacities are reported to be around 2.7 MW hydrogen output, with plant sizes up to 150 MW. Purity of produced hydrogen is very high and directly suitable for use in proton exchange fuel cells.

Proton exchange membrane electrolyzers

In proton exchange membrane (PEM) electrolyzers, the electrolyte is a polymer membrane which is only permeable for hydrogen ions. Water is split into oxygen, hydrogen ions and two electrons at the anode. The hydrogen ions travel through the membrane and, together with two electrons, form hydrogen at the cathode.

Currently, a key challenge for PEM electrolyzers is the durability of the stack. So far they reach lifetimes of 20 000 hours to maximum 60 000 hours, which at 6 500 annual full load hours (~75% load factor) would translate into a lifetime between three and nine years. Equally critical are today's investment cost, which are somewhere between USD 1 500 and USD 3 800 per kW. So far, reported bandwidth is large, as PEM electrolyzers are still manufactured in very small numbers.

Altogether this translates into levelled cost of hydrogen generation of between USD 8.9 to USD 10.3 per kg of hydrogen, again assuming costs of electricity between USD 94 (United States) and USD 120 per MWh (Japan) and an annual load utilisation rate of 75%. Based on today's technology and grid electricity, hydrogen costs would be prohibitive except for niche applications.

It is hence in niche markets like military and space engineering where PEM electrolyzers can be found today in commercial applications. But PEM electrolyzers have a great potential for cost reduction. The development of the membrane plays a crucial role – its stability is important to enhance lifetime and the geometry determines current density, which again affects the size of the stack. The improvement of the cell separator is equally important, demanding high-cost materials and showing sensible lifetimes as well. Last but not least, the precious metal demand for anode and cathode also has a big impact on total cost. Due to modular manufacturing approaches, the impact of labour costs, which currently account for 33% to 50% of the stack costs (Monjid Hamdam, 2012), will be reduced.

Currently, PEM electrolyzers with a stack size of up to 150 kW hydrogen output are commercially available, and the first 1 MW stacks are getting operational (Decourt, Lajoie, Debarre, & Soupa, 2014). Hydrogen gas purity is lower than for alkaline electrolyzers but still sufficient to be used in PEM fuel cells. Like alkaline electrolyzers, PEM electrolyzers operate at temperatures around 60°C to 80°C and hence belong to the low temperature category.

Solid oxide electrolyzers

In solid oxide electrolyzers the electrolyte is a solid ceramic membrane. On the cathode, water is split into hydrogen and oxygen ions. In solid oxide electrolyzers, oxygen ions travel from the cathode to the anode to close the circuit. Finally, oxygen ions react to oxygen on the anode.

Solid oxide electrolyzers operate at high temperatures of 700°C to 900°C. They show efficiencies of around 85% (HHV) in the laboratory, which is claimed to further increase in the future. If heat sources other than electricity are used, the conversion of electricity to hydrogen can exceed 100%. Solid oxide electrolyzers can be operated in two modes: Autothermal – the heat is provided by the electricity and allothermal, where an external high temperature heat source is used. For external heat provision, coupling with nuclear reactors might be an option. Due to the high operating temperature, solid oxide electrolyzers are not very flexible in terms of ramp-up rates, black start and load variation. This might be a hurdle in an energy system which is more and more demanding for flexibility. When coupled to an external high temperature source like a nuclear reactor, this rather rigid behaviour might even be enforced.

Table 1 Current performance of key hydrogen and fuel cell technologies

	<i>Application</i>	<i>Power or capacity</i>	<i>Efficiency *</i>	<i>Initial investment cost**</i>	<i>Lifetime</i>	<i>Maturity</i>
Generation	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	Demonstration
	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
Conversion	Alkaline FC	Up to 250 kW	~50% (HHV)	200-700 USD/kW	5 000-8 000 hours	Early market
	PEMFC stationary	0.5-400 kW	32-49% (HHV)	3 000-4 000 USD/kW	~60000 hours	Early market
	PEMFC Mobile	~80 kW	Up to 60% (HHV)	~500 USD/kW	<5 000 hours	Early market
	SOFC	Up to 200 kW	50%-70% (HHV)	3 000-4 000 USD/kW	Up to 90 000 hours	R&D
	PAFC	Up to 11 MW	30%-40% (HHV)	4 000-5 000 USD/kW	30 000-60 000 hours	Mature
	MCFC	kW to several MW	More than 60% (HHV)	4 000-6 000 USD/kW	20 000-30 000 hours	Early market
Storage	Compressor, 18 MPa	-	88-95%	~70 USD/kW _{H2}	20 years	Mature
	Compressor, 70 MPa	-	80-91%	200-400 USD/kW _{H2}	20 years	Early market
	Liquefier	15-80 MW	~70%	900-2 000 USD/kW	30 years	Mature
	FCEV on-board storage tank, 70 MPa	5 to 6kg H ₂	Almost 100% (without compression)	33-17 USD/kWh (10 000 and 500 000 units produced per year)	15 years	Early market
	Pressurised	0.1 -	Almost 100%	6 000-10 000	20 years	Mature

	tank	10 MWh	(without compression)	USD/MWh		
	Underground storage	GWh to TWh	90-95%, incl. compression	~8 USD/kWh	30 years	R&D
	Liquid storage	0.1 - 100 GWh	Boil-off stream: 0.3% loss per day	800-10 000 USD/MWh	20 years	Mature
Transmission and distribution	Hydrogen tube trailer (gaseous)	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
	Pipeline	-	95%, incl. compression	Rural: 300 000-1.2 million USD/km Urban: 700 000-1.5 million USD/km (dependent on diameter)	40 years	Mature

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

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

Notes: excl. = excluding; incl. = including; TWh = terawatt hour; GWh = gigawatt hour; HHV = higher heating value; kg = kilogram; km = kilometre; kW = kilowatt; MWh = megawatt hour; PEM = proton exchange membrane; SO = solid oxide.

Source: 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*; Elgowainy (2014), "Hydrogen infrastructure analysis in early markets of FCEVs", IEA Hydrogen Roadmap North America Workshop; ETSAP (2014), *Hydrogen Production and Distribution*; 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; Iiyama et al. (2014), "FCEV Development at Nissan", ECS Transactions, Volume 3, pp. 11-17; Linde (n.d.), *Hydrogen*, www.linde-engineering.com/internet.global.lindeengineering.global/en/images/H2_1_1_e_12_150dpi19_4258.pdf; Nexant (2007), "Liquefaction and pipeline costs", Hydrogen Delivery Analysis Meeting, 8-9 May; NREL (2010), *Molten Carbonate and Phosphoric Acid Stationary Fuel Cells: Overview and Gap Analysis*; 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*; NREL (2014), *Hydrogen Station Compression, Storage and Dispensing - Technical Status and Costs*; NREL (2012a), *National Fuel Cell Electric Vehicle Learning Demonstration Final Report*; Pacific Northwest National Laboratory (2013), *Business Case for a Micro Combined Heat and Power Fuel Cell System in Commercial Applications*; 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 (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*; US DOE (2014b), *Hydrogen and Fuel Cells Program Record*; Yang and Ogden (2007), "Determining the lowest-cost hydrogen delivery mode", *International Journal of Hydrogen Energy*, pp. 268-286.

Solid oxide electrolysers are still in the laboratory stage. Stack costs are high but could drop to below PEM electrolyser costs in the future, due to the lack of precious metals and high energy density. Life time of the cell stacks are the biggest hurdle – so far a few thousand hours with acceptable degradation are achieved. As solid oxide electrolysers would probably need higher annual full load hours due to less flexible operation, the life time needs to be increased significantly.

Table 1 summarizes key parameters to compare today's status of some of the main hydrogen generation technologies. If the produced hydrogen needs to be stored or transported it needs to be compressed. Hence, the higher the pressure at the generation stage, the lower the compression work needed later on. Increasing the operating pressure in electrolysers is energy efficient as water

or the working fluid like potassium hydroxide are compressed in liquid state (compared to compressing the hydrogen gas at a later stage, which is much more energy intense). On the other side, increasing the pressure of electrolyzers reduces operational flexibility, shortens component life-times and requires increased stability of the membrane, which in turn makes electrolyzers more costly.

Higher operating temperatures increase the potential use of heat for combined hydrogen and heat applications. In high temperature electrolyzers, using the process heat is almost imperative. Furthermore, it lowers the operating voltage of the electrolyser cell, which has a positive impact on efficiency. But as for increased pressure, operation under higher temperature increases fixed and variable costs due to more expensive materials, increased engineering complexity and reduced component life-times.

Fuel cells

Fuel cells allow the oxidation of hydrogen rich fuels without burning it with an open flame. Compared to other single-stage processes to convert chemical energy into electricity, e.g. open cycle gas turbines, the efficiency is slightly higher and in the range of 32% up to 70% (HHV). If pure hydrogen is used the exhaust of fuel cells is water vapour. As in the case of electrolyzers, different fuel cell types exist, which can mainly be distinguished by their membrane type and operating temperature.

Based on the membrane type, fuel cells (FCs) can be categorised into 1.) proton exchange membrane FCs (PEMFCs); 2.) alkaline FCs; 3.) phosphoric acid FCs (PAFCs); 4.) molten carbonate FCs (MOFCs); and 5.) solid oxide FCs (SOFCs). While PEMFCs and alkaline FCs have low operating temperatures of around 80 degree Celsius, the other FC types are operating at higher temperature levels of up to 600 degree Celsius (SOFC), which makes them more suitable for combined heat and power applications.

Similar to electrolyzers, a trade-off between efficiency and power output exists with FCs. Efficiency is highest at very low loads and decreases with power output. Also, the higher the temperature the better is efficiency at otherwise similar parameters. For stationary operation, the focus is on higher efficiencies at higher loads, which is why high temperature FCs are better suited in that case. FCs can achieve highest efficiency benefits compared to conventional technologies under transient cycles, such as in passenger cars.

Proton exchange membrane FC

PEMFCs, also known as polymer exchange membrane FCs have been developed during the last 20 years. Hydrogen is split into protons and electrons at the platinum covered anode. The protons pass the solid membrane. PEMFCs show very high reactivity, and due to the low operation temperature cold start is possible. Together with its high energy density, they are most suitable to be used in fuel cell electric vehicles (FCEVs). As a result of the low operating temperature, PEMFCs are prone to hydrogen impurities. The development of high temperature PEMFCs is targeting this problem but decreases the cold start ability. Water management in PEMFCs is complex.

To date, stationary PEMFCs have rather low efficiencies of around 32% to 49% (HHV) and investment costs are still high in the range of USD 3 000 to USD 4 000 per kW. For stationary application, current life times of up to 60 000 hours are low and needs to be increased to at least 80 000 hours on average. The low operating temperature limits its use for combined heat and power (CHP) applications.

PEMFCs for FCEVs achieve better efficiencies of up to 60% (HHV) but have low life times of below

5 000 hours (which is sufficient to achieve total mileages of around 150 000 to 200 000 km). PEMFCs for mobile applications show the highest cost reduction potential at high production volumes. Currently, reduction of noble metals used as a catalyst is a priority to reduce costs.

Alkaline FC

Like for alkaline electrolyzers the electrolyte of alkaline FCs is a potassium or sodium hydroxide solution. Negatively charged hydroxyl ions pass from the cathode to the anode. Electric efficiency is around 50% (HHV). As alkaline FCs not only require pure hydrogen but also pure oxygen, currently only little commercial interest exists. Alkaline FCs have the longest development history, and were used by the NASA for the Apollo missions as well as on space shuttles.

Phosphoric acid FC

In PAFCs phosphoric acid is used as electrolyte. They were relatively widely deployed, in the 1970's more than 500 PA FC power plants have been installed globally. To date, the largest fuel cell is an 11 MW PAFC system built by the Tokyo Electric Power Company (Sammes, Bove, & Stahl, 2004). PAFCs have electric efficiencies of around 30% to 40% (HHV), and the higher operating temperature of more than 200 degree Celsius makes them suitable for CHP applications. As a result of the higher operation temperature, they can also be fuelled with less pure hydrogen. On the other side, power density is low resulting in large sizes and heavy weights.

Molten carbonate FC

MCFCs belong to the high temperature FCs, with operating temperatures of 600 degree Celsius and above. Due to the fact that hydrogen rich gases can be reformed internally to hydrogen, MCFCs can be operated with natural gas, biogas or coal based syngas. MCFCs show efficiencies of more than 60% (HHV), and the use of the resulting high temperature waste heat could increase overall efficiencies to more than 85%. Although MCFC resist carbon impurities, sulphur contained in the gas needs to be removed. Currently, costs of the FC stack account for almost 60% of the MCFC system costs (including BOP, gas clean up, pre-reformer, water management, heat exchangers, control, inverter) (National Renewable Energy Laboratory, 2010). The same NREL publication concludes that no single issue could achieve significant cost reductions, but stack life time, power density and cost reduction of gas cleaning are the most important R&D areas to bring down system costs. However, they conclude that "even under the most optimistic circumstances, it is not likely that first costs for an MCFC power plant can be brought much below USD 2 000 per kW" (National Renewable Energy Laboratory, 2010).

Solid oxide fuel cell

Like MCFCs, SOFCs belong to the high temperature FCs with operating temperatures of up to 1 000 degrees Celsius. SOFCs have a ceramic electrolyte and, like MOFCs, can reform the gaseous fuel to hydrogen internally, which makes them suitable for the use of other hydrogen rich gases, such as natural gas, bio gas or syngas from coal. Similarly, sulphur impurities needs to be removed. Due to the very high operating temperature, SOFCs need a time consuming heating-up process, which significantly reduces operational flexibility. To date, costs per kW are between USD 3 000 per kW and USD 4 000 per kW. Stack life-time is currently up to 90 000 hours.

Hydrogen storage and transmission

The ability of hydrogen to store either very large quantities of low-carbon energy over long time periods or to store low-carbon energy under restricted space and weight requirements (e.g. for application in FCEVs) is a key feature of this energy carrier. Hence, the respective storage technologies play a crucial role when evaluating the potential use of hydrogen and fuel cell technologies.

Storing electricity is particularly difficult, and compared to other options such as batteries, pumped hydro storage (PHS) or compressed air electricity storage (CAES), hydrogen provides a better performance with respect to energy density. Nonetheless, although its weight specific energy density (energy per kilogram) is very high, its volumetric energy density (energy per cubic meter) is very low. Consequently, it is necessary to increase the volumetric energy density to economically transport and store hydrogen. This can either be achieved by compressing the hydrogen gas or through the liquefaction of hydrogen, although both options are based on energy intensive processes.

Compressed hydrogen storage requires pressures between 18 MPa up to 70 MPa to economically store the hydrogen gas. For example, the upper pressure limit is needed to accommodate enough hydrogen to achieve FCEV driving ranges of around 500 km, without negatively affecting the useful space for passengers and baggage.

Liquefied hydrogen storage (also known as cryogenic hydrogen) requires a temperature as low as minus 253 degrees Celsius under atmospheric pressure. Achieving this extremely low temperature (absolute zero is at minus 273.15 degree Celsius) requires high compression work, using several stages of compressors as well as costly heat exchangers for a combination of multiple cooling cycles. During this very energy intensive process, between 25% and 40% of the energy stored are used for hydrogen liquefaction.

This technology section is structured as following, using storage size and time as classification

- Large scale, long term storage: Pressurised underground storage
- Medium-scale, medium-term and small-scale, short term storage: Pressurised and cryogenic tanks, metal hydrides, carbon nano structures

Large-scale underground storage

The amount of energy, which can be stored underground using hydrogen gas, is determined by the storage volume, its pressure and its temperature. The aim is to find a storage site which:

- assures the storage of hydrogen gas within acceptable leakage limits;
- provides an optimum between storage pressure and hence storage depth (pressure is determined by the thickness of the overlaying geologic formation) as well as the economics of the borehole. With increasing depth, costs for the borehole increase significantly. A value of 1 000 m has been proven practicable in the past;
- constraints the pollution of the stored hydrogen gas by bacteria, other non-organic elements like sulphur and organic compounds (remaining from former oil and gas storage) to acceptable limits.

In general, underground storage sites can be classified into porous storage sites and salt caverns. While porous storage sites like depleted oil and gas fields or aquifer formations are naturally occurring, salt caverns have to be developed in existing underground salt formations. All three options have specific advantages and disadvantages, which can be summarised as following

(adapted from from Stolzenburg, 2014):

Salt caverns show the required tightness and no in-situ reactions with microorganisms, remaining hydrocarbons or other chemical elements are known so far. They allow for high gas exchange rates, which are mainly limited by the size of the borehole and the thermodynamics of the charging/depletion process. Only small amounts of “inert” cushion-gas are necessary. On the other side, the development of the salt caverns is costly and also requires the recycling of large amounts of sole water.

Depleted oil and gas fields have known geological parameters, proven tightness and costly boreholes are already existent. Due to the presence of various microorganisms, non-organic elements like sulphur as well as remaining hydrocarbons, in-situ reactions, which pollute the hydrogen gas are possible. The porous nature of the storage limits the gas exchange.

Aquifer formations show the highest capacity potential but are the least mature option due to little exploration to date. In-situ reactions with microorganisms and non-organic elements are possible. Due to great depths, a big amount of cushion gas, which decreases the net storage capacity is necessary. Gas exchange rates are limited.

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 (see also Table 7 of the Technology Roadmap on Hydrogen and Fuel Cells).

Today, salt caverns for hydrogen storage already exist in the United States and the United Kingdom. Storage capacities are between 210 m³ and 580 m³ at pressures between 4.5 MPa and 15 MPa. Praxair's underground hydrogen storage, which started operation in 2007, can store up to around 120 GWh of hydrogen, which equals the annual electricity consumption of almost 12 000 average households in the European Union (Bertoldi, Hirl, & Labanca, 2012).

The total efficiency of hydrogen underground storage is mainly determined by the efficiency of the compressor, accounting for around 88% to 95% (based on the chemical energy of the hydrogen). Common storage pressures are around 2 MPa and 18 MPa.

Total investment costs for developing a salt cavern for hydrogen underground storage can be split into surface and sub-surface developing costs. On the surface, the main cost factors are the compressors as well as the hydrogen conditioning technology (to satisfy end-use quality requirements) as well as common infrastructure to maintain the energy storage. The main sub-surface cost factors include the borehole, the development of the cavern and the cushion-gas (i.e. the minimum gas content which needs to stay in the underground storage). In total, current investment costs are around USD 8 per kWh of stored hydrogen gas, with the potential to drop to below USD 1 per kWh.

Medium and small-scale hydrogen storage

Pressurised tanks

Pressurised tanks are the most common and mature hydrogen storage technology. Those can have the form of vessels or bottles, and are so far manufactured in sizes between 100 kWh to 10 MWh of hydrogen capacity. Current storage pressures are between 20 MPa and 70 MPa (Decourt, Lajoie, Debarre, & Soupa, 2014). Pressurised tanks are used in stationary and mobile applications – as buffer storage, for on-board storage in FCEVs and to transport hydrogen with tube trailers.

Pressurised tanks are not self-depleting, i.e. they allow for long storage times, and efficiency without compression is almost 100%.

Costs of pressurised tanks are a function of pressure. At lower pressures, today's investment costs

are around USD 6 to USD 10 per kWh of hydrogen.

Highest pressures occur in on-board storage systems in FCEVs. Tanks developed for 70 MPa storage pressure are made out of composite materials, which are still costly. At assumed large-scale production, today's costs for on-board storage systems in fuel cell PLDVs are estimated to be around USD 19 per kWh (Argonne National Laboratory - Nuclear Division, 2010). The same study on compressed hydrogen storage systems from Argonne National Laboratory concludes that more than 75% of the manufactured costs of the on-board storage tank are linked to the carbon fibre structure, and that only a little more than 1% of the total costs occur during assembly and testing, assuming large-scale manufacturing (Argonne National Laboratory - Nuclear Division, 2010). Hence, drastically reducing costs of future FCEV on-board hydrogen storage tanks depends on reducing the costs of these composite materials.

Tube trailers are used for hydrogen transport with truck-trailer combinations. Today's gaseous tube trailers have pressures of up to 60 MPa and can transport up to 1 000 kg of gaseous hydrogen at investment costs of around USD 1 000 per kg of hydrogen.

Cryogenic tanks

Cryogenic tanks are filled with liquid hydrogen at atmospheric pressure and minus 253 degrees Celsius. They are isolated pressure tanks, and as temperature rises pressure increases. Through constantly releasing a so-called boil-off stream, very low temperatures can be sustained in the tank. On the other side, the boil-off stream constrains the storage time to few days and can cause other practical problems, e.g. with respect to parking in closed underground park spaces if used in FCEVs. That is why all recent FCEV demonstration projects used pressurised tanks and gaseous hydrogen.

Through liquefaction of hydrogen the volumetric density can be increased significantly, which allows for example the transport of around 4000 kg of hydrogen via a truck trailer combination.

Investment costs range between USD 1 and USD 10 per kWh. The efficiency of the storage tank is a function of time since around 0.1% to 0.5% of the stored hydrogen needs to be released per day (Decourt, Lajoie, Debarre, & Soupa, 2014).

Metal hydrides

Metal hydrides for hydrogen storage show high volumetric energy density at ambient pressure and temperature. They offer a partial solution to the volumetric density problem. On the other side, they provide very low weight specific densities, which excludes them for example as a storage medium for mobile applications. The underlying principle is the reversible and exothermic hydration of combinations of different metals, which release the stored hydrogen upon heat supply.

Carbon nano-structures

The adsorption of hydrogen under ambient pressure and temperature on large carbon surfaces, e.g. carbon nano-tubes might be a promising storage option, although research is still in an early phase and more recent results show lower weight based adsorption potential than formerly claimed (Liu, 2010).

Compressors

Compressors are a key technology when discussing hydrogen storage. Different pressure levels range from 2 MPa to 18 MPa for underground storage, over 35 MPa to 500 MPa for gaseous truck

transport up to 70 MPa for on-board storage in FCEVs.

Various types of compressors for hydrogen compression exist. Gases can be compressed using positive displacement or dynamic principles. While displacement based compressors reach high pressure ratios at lower flows, high flows at lower compression ratios are achieved with turbo compressors. Both principles are used when compressing hydrogen. For hydrogen applications it is particularly important to prevent pollution of the hydrogen gas with oil used for lubrication. As heating of the hydrogen during compression leads to lower compression ratios, and oil-cooled compressors cannot be used, oil-free compressors for hydrogen applications show lower efficiencies at higher costs (Stolzenburg, 2014).

A novel technology for hydrogen compression is the ionic compressor, which, in a very simplified view, uses an ionic liquid column instead of a metal piston to compress the hydrogen gas.

Hydrogen transmission and distribution

For hydrogen transmission and distribution to supply refuelling stations, gaseous truck transport, liquefied truck transport or pumping gaseous hydrogen through pipelines comprise the available options. The lowest cost pathway depends among many factors, with hydrogen demand at the refuelling station and T&D distance being the most important ones.

Gaseous tube trailers are so far limited to capacities of up to 1 000 kg, but average existing tube trailer size might be smaller in the range of 300 kg to 600 kg of hydrogen. Hydrogen delivery to the station would imply short delivery intervals, once hydrogen demand at the station scales up. Assuming average hydrogen demand per vehicle refuelling to 5 kg, a 600 kg tube trailer would be sufficient to refuel less than 120 vehicles. For comparison, today's average petroleum fuel stations in Europe serve around 200 cars per day.

As more than one hydrogen delivery per station per day is not practical, higher capacity hydrogen refuelling stations (with capacities higher than 1 000 kg of hydrogen per day) would either need to be delivered with liquefied hydrogen or via pipeline connection.

Liquefied truck trailers can achieve capacities of up to 4 tons of hydrogen. While the trailer itself would impose no economic barriers, the liquefaction of the hydrogen is costly and linked to significant energetic losses.

Hydrogen pipelines are very efficient but the upfront investment and the risk linked to uncertainty on future utilisation are challenging.

In summary, from a cost perspective, gaseous truck transport is viable at lower hydrogen demand and short transport distance, liquefied trucking is preferable at high transport distances even if demand stays moderate, while pipeline transport is most efficient at high hydrogen flows over a broad range of distances.

Hydrogen in the iron and steel industry

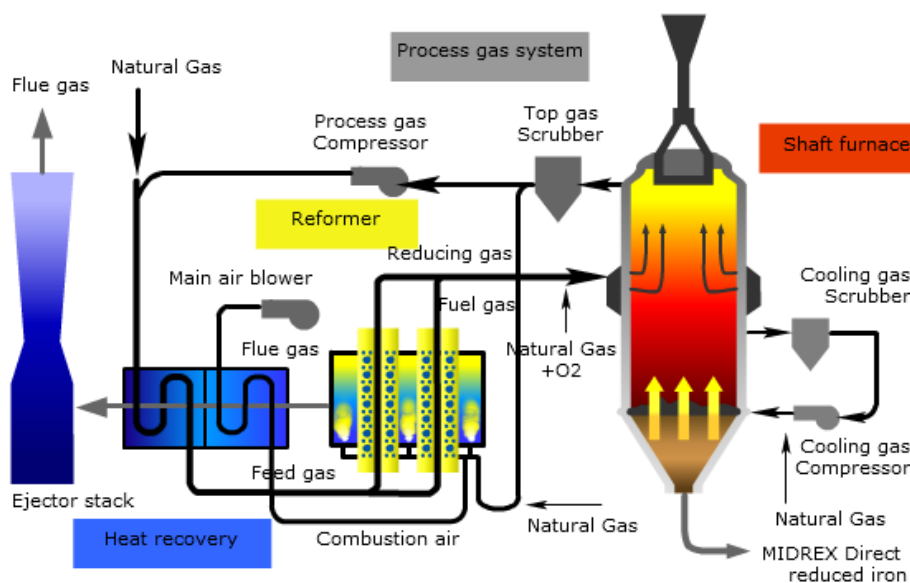
The direct reduced iron (DRI) and the smelt reduction (SR) process allow the production of iron without the need of coke. As coke production is very carbon intensive, important emission reductions can be achieved when the whole process chain is assessed.

Direct reduced iron

Direct reduced iron is produced from reducing iron ore by using a gas mixture containing hydrogen and carbon monoxide called *syngas*² as reducing agent that is generated at site from either coal or natural gas, alternatively natural gas or COG can also be directly used as reducing agent. Throughout this reduction process iron ores remain solid, and get subsequently melted into liquid steel in an electric arc furnace (EAF).

Commercial DRI processes are available as Midrex, HYL and Circored process. Global penetration of DRI processes is limited to just 71 Mt DRI (about 7% global crude steel production) and it is mostly deployed in India and Middle East that account for 94% of coal based and 41% gas based DRI global production respectively.

Figure 1 Midrex process diagram



Source: <http://www.steeluniversity.org/content/html/eng/default.asp?catid=13&pageid=2081272423>

Smelt reduction

SR processes consist of a first pre-reduction stage of iron ore using off-gases, which mainly contain hydrogen and carbon monoxide and which are generated at the melter-gasifier during coal gasification, followed by melting of pre-reduced iron ore in the same melter-gasifier. As in the case of pig iron, iron produced through SR processes is subsequently reacted with oxygen in a basic

² *Syngas* or synthesis gas refers to a gas mixture that mainly contains hydrogen and carbon monoxide (CO) that is generated from a carbon based material (coal, natural gas, etc) through steam reforming reaction or gasification.

oxygen furnace to produce crude steel.

Commercial SR processes such as Corex (using a reduction shaft for the pre-reduction phase) and Finex (iron ore pre-reduction takes place in a multistage fluidised bed reactor) are available. In the case of the Finex process the melter-gasifier off-gas typically contains 15% hydrogen, which rises up to 25% in the product gas entering the fluidised bed reactors after CO₂ removal (Posco, 2008). Global installed production capacity of SR processes is very limited (6.8 Mt of hot metal) and is mainly based in South Korea, China and India.

Table 2 Main technology options for hydrogen use as reducing agent in the iron and steel sector.

<i>Process</i>	<i>Type</i>	<i>Research programme</i>	<i>Current status</i>	<i>Commercial available by</i>	<i>Energy intensity (GJ/t material output)</i>	<i>Investment costs (USD/t material output)</i>
DRI processes	DRI	-	Commercial	-	10.9 - 19.9	285
Smelting reduction processes	SR	-	Commercial	-	15.3 - 29.7	315
BF - TGR	BF	ULCOS	Pilot phase	2025	12.2	240-337
ULCORED	DRI	ULCOS	Pilot phase	2030	8.7	350
HISARNA	SR	ULCOS	Pilot phase	2030	12.2	140
COG reforming hydrogen amplification integration	BF/SR	COURSE 50 POSCO-RIST	Pilot phase (**)	2030 (*)	Not available	Not available

Note: Energy intensity values are provided at best available technology performance level per tonne of corresponding material for each process, and include electricity. Thus energy intensity values provided are only comparable for processes of the same type. Energy intensities for smelting reduction processes do not include generated off-gases. Energy intensity values for non commercial technologies have certain uncertainty due to lack of technology performance data. CAPEX values refer to the base year and exclude carbon capture equipment cost. Plant cost excludes costs for contingency, fees, and owner costs. Plant cost for technologies operating with oxygen rich conditions excludes air separation unit cost. Oxygen and amine solvents are considered exogenous commodities purchased at a base price of 128 USD/kNm³ and 1.52 USD/kg respectively. (*) COURSE 50 project's milestones aim at having the *first production unit of this type* in operation by 2030 assuming CO₂ transport and storage is economically viable by then. (**) Different COG reforming catalysts and hydrogen enriched reducing gas for iron ore have been tested at laboratory scale. A pilot plant for the COG reforming process integrated in a BF is under construction.

Source: IEA GHG, 2013a; BCG and VDEh, 2013; EC, 2012; ETSAP, 2010; LBNL, 2008; Knop et al, 2008; IEA, 2007; IEA estimates.

Several research programmes have been focusing 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. For instance, the European based Ultra-Low Carbon Dioxide Steelmaking (ULCOS) programme started in 2004 has developed improved a gas based DRI process (ULCORED) as well as a SR based upgraded process (Hisarna). Both processes present reduced energy requirements compared to their respective reference processes, and energy savings account for 2.2 GJ/t DRI (ULCORED) and 3.1 GJ/t hot metal (Hisarna), respectively. Since the Hisarna process operates with

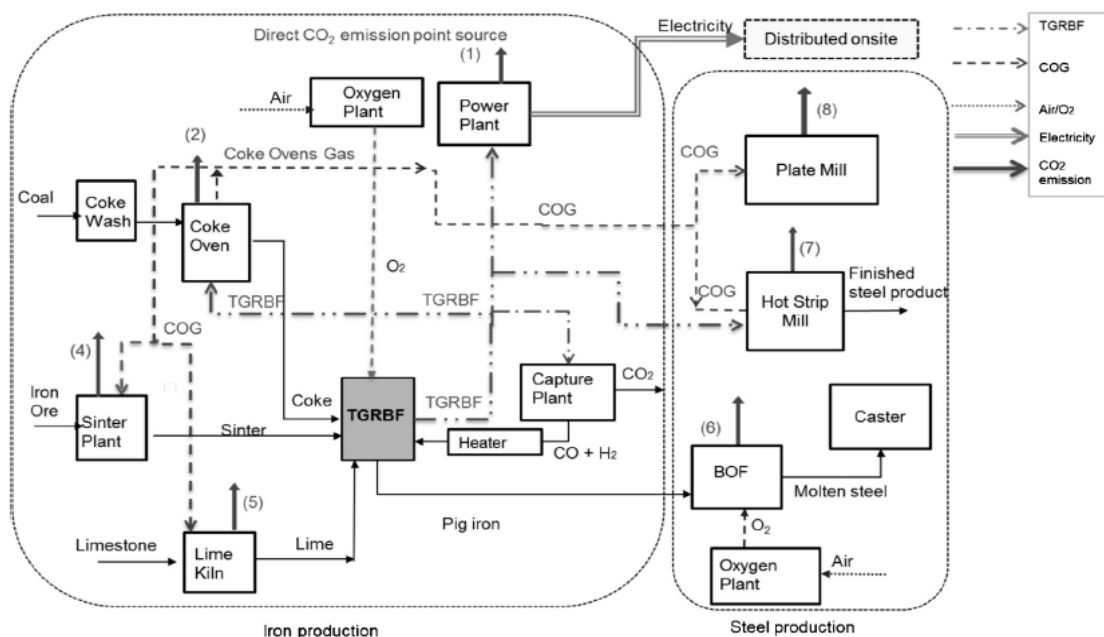
pure oxygen, it delivers off-gas with high CO₂ concentration, which in turn facilitates the implementation of carbon capture and storage (CCS). Commercial grade steel was firstly produced based on the Hlsarna process in 2013 and continued in June 2014. A longer trial of about 90 days to determine the process stability and continuous operation is planned for 2016. The outcome of this trial will determine the design parameters for a commercial-scale plant in the following years (ESEC, 2014). Currently, there are plans to build an ULCORED pilot plant of 1 t DRI/h to demonstrate the process (LKAB/ULCOS, 2013).

Blast furnace top gas recovery

ULCOS also developed a BF arrangement that collects, treats and reuses the blast furnace top gas in the process as reducing agent displacing the use of coke. Using this process, energy demand from coke is reduced by 2.7 GJ/ t pig iron³ compared to a typical BF. However, when assessing the overall process chain, additional energy savings in the order of 1 GJ/ t pig iron occur, as coke production is very energy intense (11.3 GJ/t coke). The BF top gas recovery system (BF-TGR) also operates with pure oxygen that enables a greater concentration of CO₂ in the top gas and thus an easier carbon capture. Recovered BF top gas contains 9% (volume) of hydrogen and reaches around 14% (volume) when returning to the BF after CO₂ removal (IEA GHG, 2013b).

BF-TGR is at demonstration stage, a pilot plant was planned to be built at the Florange Arcelormittal site (France) in 2013, but the project was stopped for technical and financial reasons. Demonstration at greater scale will be required to allow this technology to reach commercial stage.

Figure 2 Blast furnace with top gas recovery diagram



Source: Minh et al, 2013.

COG reforming and hydrogen amplification

The CO₂ Ultimate Reduction in Steelmaking process by Innovative technology for cool Earth 50 (COURSE 50) is a Japanese research programme launched in 2008 that focuses on developing alternative reducing agents for iron ore reduction, among others areas, to achieve a 30% CO₂

³ Pig iron refers to the iron produced in a blast furnace.

emission reduction from blast furnaces.

The principle of the main research path is to enrich the hydrogen content of the COG from an average of 55% to 63-67% through reforming tar contained in that gas mixture to reduce the coke needs for the iron ore reduction in the blast furnace (Shigeaki, 2013). This process requires the development of new catalysts that can yield the targeted hydrogen conversion at the required operating conditions. Additional CO₂ emission savings could be achieved if the process were to benefit from the availability of low-carbon footprint hydrogen generated elsewhere and delivered at a competitive price (Shigeaki, 2013).

In addition to the environmental benefits, impacts on iron ore reduction process performance when using hydrogen rich reducing gases are being analysed. Latest studies indicate that intensive hydrogen injection in BF impacts the kinetics of the reduction by delaying the reaction in the stack part of the furnace (Nogami et al, 2012). The COURSE 50 process considers the capture of the CO₂ from the BFG.

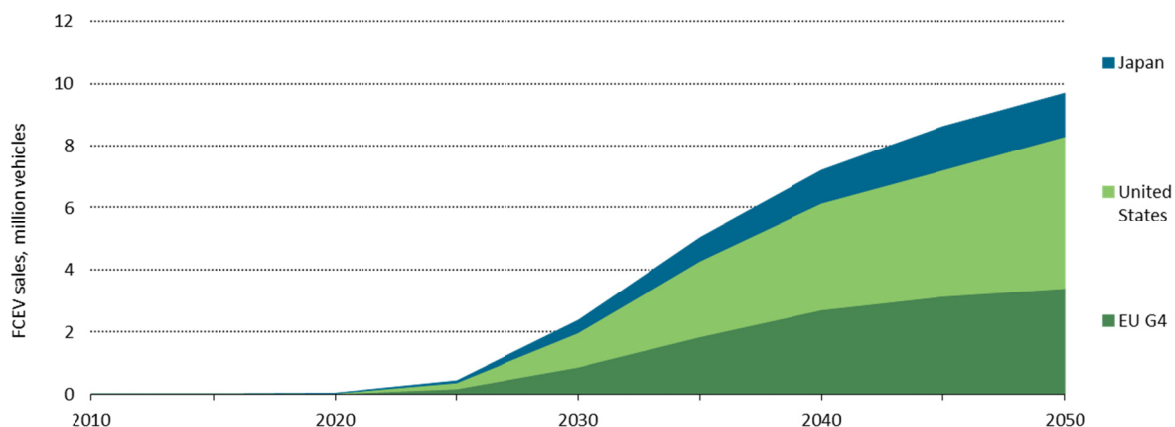
The Korean consortium POSCO/RIST is also developing a conversion process to produce a rich-hydrogen gas from COG and CO₂ through steam reforming, which could be used for iron ore reduction in a BF or SR process. The conceptual design of the COG reforming process was completed in 2012, and a pilot plant is currently under construction (Posco/RIST, 2013).

Vision – Transport modelling insights

The following section aims at providing further insights to the transport part of the “Vision” of the Technology Roadmap on Hydrogen and Fuel Cells. The idea is to make the results of the 2DS high H₂ more accessible and to further investigate regional differences.

FCEV sales scenario

Figure 3 FCEV sales in the 2DS high H₂ for EU 4, Japan and the United States until 2050



Key point: FCEV roll-out in the 2DS high H₂ is ambitious, yet feasible when compared to EVmarket introduction

The underlying FCEV sales scenario within the 2DS high H₂ assumes around 30,000 FCEVs brought on the market in the EU 4, Japan and the United States in 2020 (Figure 3). By 2025, around 400 000 FCEVs are sold in the respective regions per year, increasing to more than 2.3 millions annual sales by 2030. Reaching a 25% share on vehicle stock by 2050 necessitates this share on sales to be reached by 2040.

This highly ambitious FCEV sales scenario requires 80% annual growth of FCEV sales between 2020 and 2025, 16% annual growth between 2030 and 2035 and a stabilisation towards annual growth rates below 5% after 2040. The market introduction of EVs following the years after 2010 can be used as reference – an average growth rate of 171% has been achieved over the course of the years 2010 to 2014 (Table 3). Growth rates of FCEV sales are assumed to be about half of those of EVs, taking into account the much more restricted access to refuelling infrastructure in the beginning.

Table 3 Electric vehicle sales

	2010	2011	2012	2013	2014	2010-2014
BEV sales	4 917	38 268	57 708	108 738	173 346	378 060
PHEV sales	768	8 854	60 018	97 076	132 174	292 122
Total EV sales	5 685	47 122	117 726	199 884	305 520	670 252
Annual growth rate		729%	150%	70%	53%	~171%

Source: EVI, 2015

FCEV costs

Costs of FCEVs drop quickly with sales in the 2DS high H₂ (Figure 4, upper graphs), assuming learning rates of 20% (i.e. the cost of the FCEV power-train drops by 20% each time cumulative vehicle sales double). Compared to other vehicle technologies included in the IEA Mobility Model, the learning rate of fuel cell systems for FCEVs is significantly higher – for example learning rates for batteries account for 15%. By 2050, costs of the FCEV system including the balance of plant (BOP) and all controls drops to USD 40 per kW, (Table 4).

Table 4 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
<i>Thereof</i>				
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
<i>Specific costs</i>				
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
<i>Other parameters</i>				
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 kgH₂ 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% (H₂ tank), 15% (electric motor, power control, battery) and 20% (fuel cell system) per doubling of cumulative deployment.

Costs of all vehicles are the sum of the costs for the glider (i.e. the vehicle chassis with all common parts except the powertrain), the engine and the energy storage. For all vehicle types, costs of glider and power train increase over time to reflect the cost of energy efficiency technology deployment.

Differences in costs of PLDV technologies among regions (Table 5) are due to different assumptions of average vehicle size. While vehicle size remains constant in the United States and EU 4, it is assumed to slightly increase over time in Japan, resulting in a higher cost increase for all vehicle types compared to the other regions. The relative cost difference between PLDV technologies is the same for all regions.

In the very early phase, FCEV size and costs are assumed to be equal in all regions (mainly due to a lack of FCEV models), but as the market develops, regional size and cost differences are applied to FCEVs as well. Compared to the United States, this behaviour causes FCEVs to be more costly

relative to the benchmarking technology in Japan and EU 4 in the very beginning, as the average gasoline vehicle (which is used as benchmark) is smaller than in the United States.

Table 5 Cost of PLDVs by technology as computed in the model

		Today	2030	2050	Unit
United States	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	35 400	32 800	34 000	USD
	FCEV	60 000	33 600	33 400	USD
EU 4	Conventional ICE gasoline	26 000	28 100	29 400	USD
	Conventional ICE diesel	26 600	28 800	30 100	USD
	Hybrid gasoline	27 200	28 900	30 900	USD
	Plug-in hybrid gasoline	29 400	30 200	31 300	USD
	BEV	32 200	29 800	30 900	USD
	FCEV	60 000	30 600	30 300	USD
Japan	Conventional ICE gasoline	20 500	23 000	25 200	USD
	Conventional ICE diesel	21 000	23 600	25 800	USD
	Hybrid gasoline	21 500	23 600	25 900	USD
	Plug-in hybrid gasoline	23 200	24 700	26 800	USD
	BEV	25 400	24 400	26 500	USD
	FCEV	60 000	25 000	26 000	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. Costs are for BEVs with a 150 km driving range.

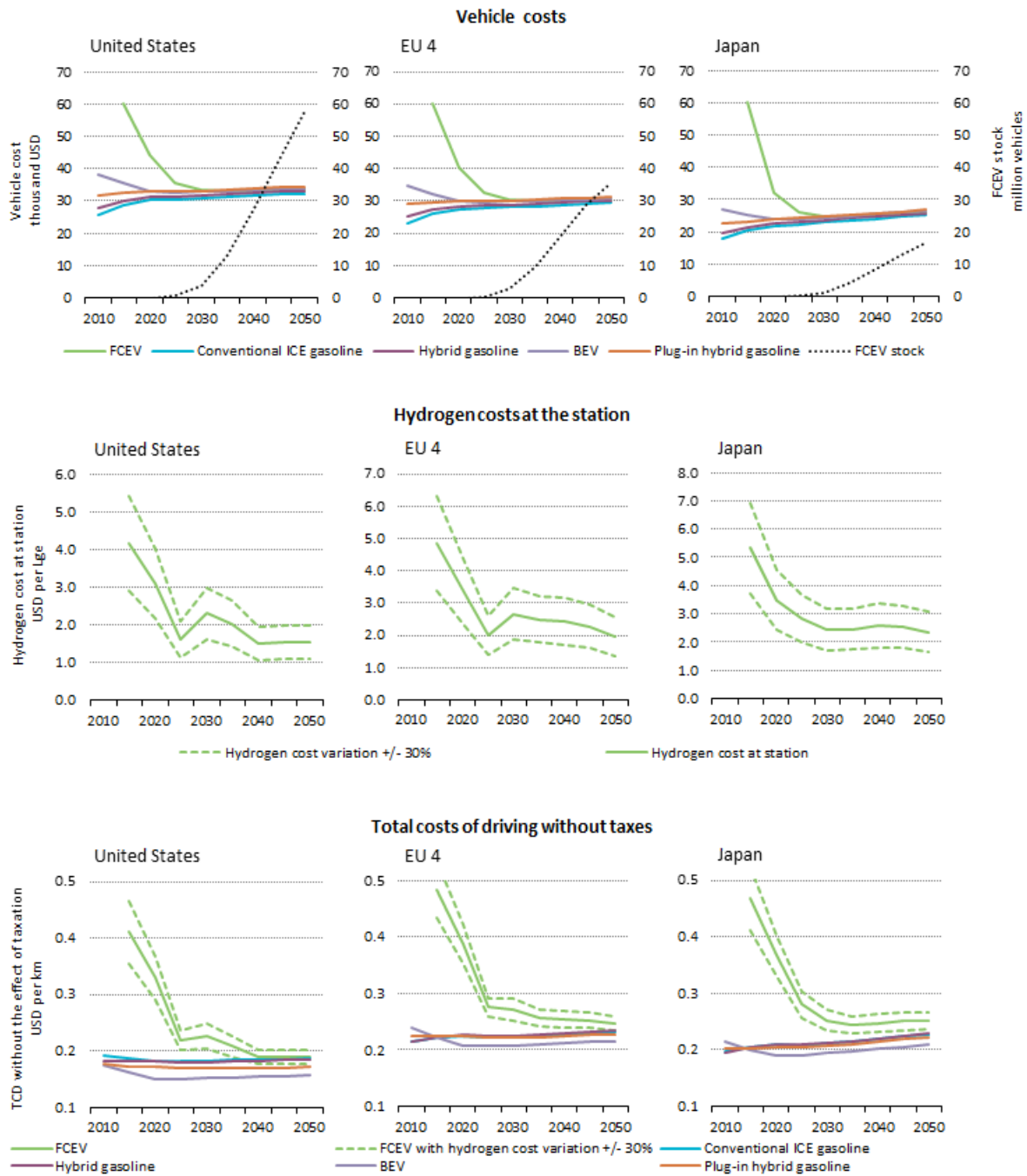
Source: IEA analysis

Hydrogen costs at the pump

Hydrogen costs drop quickly in the beginning of the FCEV roll-out, as relatively few stations are clustered around selected demand centres and alongside main corridors (Figure 4, middle graphs). To attract interest of a large share of potential FCEV buyers, the retail network soon needs to be expanded to average sized cities (~25,000 inhabitants). This necessary network expansion causes: 1.) a large number of relatively small stations to be build; 2.) the significant spatial expansion of hydrogen T&D with relatively low daily throughput and 3.) dropping average utilisation rates to just above 45% to 50% from 60% to 70% already reached in 2025. Especially the relatively small daily demand at stations in the “average cities” causes overall average hydrogen costs at the pump to increase again after 2025 in the United States and EU 4.

Hydrogen T&D costs at the pump show significant differences between the regions. This is partly due to different hydrogen production pathways and resulting costs (based on regionally different availability and costs of energy sources for hydrogen production, see Figures 17 and 18 in the Technology Roadmap on Hydrogen and Fuel Cells). Furthermore, regional demand patterns, which influence the utilisation rate of T&D and retail stations, have a significant impact on costs. Hydrogen infrastructure can be used more efficiently, and benefits from higher hydrogen throughput materialize much earlier in the United States when compared to EU 4 or Japan. This is due to much higher annual mileages, larger and less efficient FCEVs (FCEVs in the United States are assumed to consume around 30% more hydrogen per km compared to those used in EU 4 and Japan) and thus higher hydrogen demand at comparable market penetration.

Figure 4 FCEV costs, hydrogen costs at the pump and total costs of driving for the 2DS high H₂ for EU 4, Japan and the United States.



Key point: The nation or region wide expansion of the hydrogen T&D and refuelling network slows down the decline of hydrogen costs at the pump, which in turn delays (United States) or prevents (EU 4, Japan) FCEVs from achieving parity of costs of TCD with efficient gasoline ICE vehicles without any further incentives

Total costs of driving

Total costs of driving (TCD) without the effect of taxation are shown in Figure 4 in the lower graphs. TCD are the sum of vehicle costs and total vehicle lifetime fuel costs (including the costs of hydrogen generation, transmission, distribution and retail) divided by the total lifetime vehicle

mileage. Although vehicle costs drop quickly with deployment, the rather slow decrease of hydrogen costs over time in the 2DS high H₂ significantly affects the decrease of TCD of FCEVs over time, delaying parity of TCD with efficient conventional vehicles by ten years (United States) or preventing parity of costs at all (EU 4 and Japan). Although the increase in hydrogen costs due to network expansion is partly a modelling artefact, it still hints at a potential source of economic concern.

The dashed green lines in the lower graphs in Figure 4 show the impact of a variation of hydrogen costs at the pump by +/-30% on TCD. While 30% lower costs of hydrogen would bring forward parity of costs by five years (to around 2035) in the United States, the lower hydrogen costs would still be not sufficient to achieve cost parity with high efficient gasoline vehicles in EU 4 and Japan.

The effect of fuel tax exemption for hydrogen

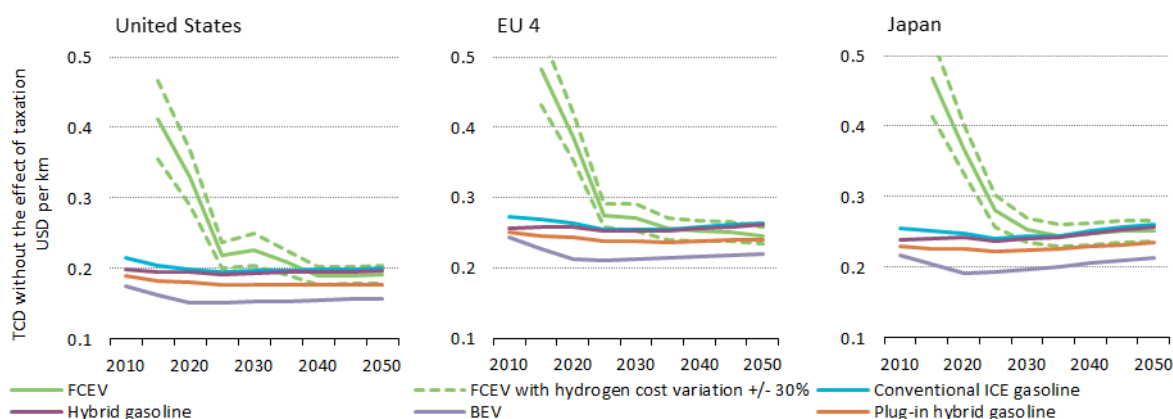
To correctly account for TCD from a consumer perspective, fuel taxes needs to be included when calculating TCD_{tax}. Currently, tax levels on petroleum fuels in the EU and in Japan are accounting for about 100% of the petroleum fuel costs, and are assumed to stay the same in the future. For the United States, a future petroleum tax level of 30% is assumed for this analysis.

Imposing a fuel tax exemption for hydrogen has a strong impact on total costs of driving of FCEVs – in EU 4 and Japan cost parity with gasoline ICEs is reached by 2035 in this case. The variation of hydrogen costs by +/- 30% at the pump accelerates or delays parity of costs by five years in all three regions.

Consequently, differentiated fuel taxation can be a powerful mean to increase the attractiveness of FCEVs to the consumer. Impacts of the exemption of hydrogen from fuel taxes on government revenue are not analysed in detail, but when FCEVs achieve cost parity with efficient gasoline vehicles (around 2035), the fleet of FCEVs is still relatively small compared to the total PLDV fleet, accounting for roughly 6%. Hence, the lower petroleum tax revenue might be acceptable.

The moment FCEVs achieve parity of TCD_{tax} with effiecient gasoline PLDVs, hydrogen can be taxed, although not to the same extent as petroleum fuels, in order to maintain cost competitiveness.

Figure 5 Total costs of driving with petroleum fuel taxes and fuel tax exemption of hydrogen for EU 4, Japan and the United States for the 2DS high H₂

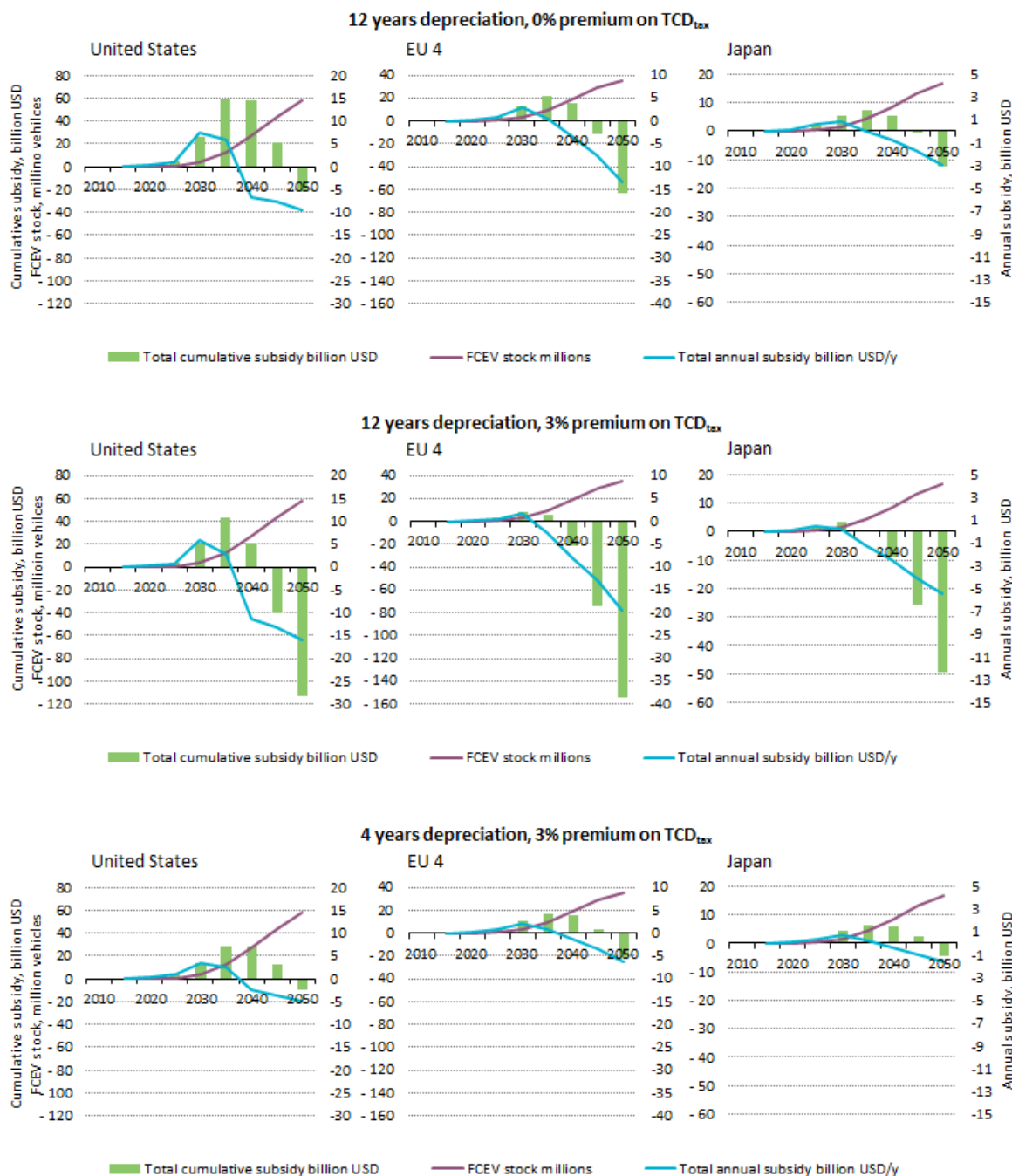


Key point: The exemption of hydrogen from fuel taxation helps FCEVs to achieve cost competitiveness with efficient gasoline ICE vehicles by 2035 in all three regions

Cumulative subsidy to close the economic gap

To close the economic gap between TCD_{tax} of FCEVs and efficient gasoline ICE vehicles prior to achieving cost parity, additional direct subsidies to purchase FCEVs might be necessary to attain the consumer's interest.

Figure 6 Total cumulative subsidies as a function of depreciation time and cost premium per km (of FCEVs compared with gasoline ICE cars)



Key point: Both, depreciation time and acceptable per km cost premium have a big effect on total cumulative subsidies

The introduction of electric vehicles (EVs) in Norway and Netherlands has shown that strong purchase incentives can convince consumers to change their preferences – by 2014 about 12% of

the Norwegian and 4% of the Dutch consumers opted for EVs, with more than 80% of the Norwegian consumers opting for a BEV, regardless their limited range (EVI, 2015).

Based on a rapid FCEV market uptake, the cumulative subsidy requirement *additional to the fuel tax exemption*, to reach parity of TCD_{tax} with gasoline ICEs, accounts for roughly USD 59 billion in the US, USD 22 billion in EU 4 and USD 7.5 billion in Japan (Figure 6, upper row).

If consumers were to accept a 3% premium on TCD_{tax} for FCEVs (compared to gasoline ICEs), demand for additional direct subsidies would shrink to USD 43 billion in the US, USD 8 billion in EU 4 and USD 3 billion in Japan (Figure 6, middle row).

Comparing TCD_{tax} over the first four years of the vehicle life time while depreciating vehicle purchase costs over the same short period, pronounces the effect of higher vehicle costs of FCEVs relative to other PLDV options. Assuming furthermore that the consumer were to accept a 3% premium on TCD_{tax} relative to the efficient gasoline ICE car, total cumulative required subsidy in addition to the fuel tax exemption of hydrogen would equal to about USD 28 billion in the United States, USD 17 billion in EU 4 and USD 7 billion in Japan (Figure 6, lower row).

Obviously, consumer behaviour plays a major role when estimating costs of large-scale FCEV market introduction and the better understanding of consumer preferences and their willingness to pay for low-carbon, long-distance driving might be essential.

Hydrogen T&D infrastructure

Hydrogen can be transported from the centralised production plant to the retail station by truck-trailer combinations or by pipeline. In case of truck transport, two options exist: hydrogen can be transported in gaseous form with high pressure hydrogen tube trailers or in liquefied form using liquid tankers.

According to a paper by Yang and Ogden (Yang & Ogden, 2007), transport distance as well as daily hydrogen throughput are the principal decision variables to determine the most cost efficient hydrogen transportation option. The IEA's Mobility Model has been refined in order to determine the most cost efficient hydrogen T&D method, based on the results provided by Yang and Ogden.

Therefore, as described in the Technology Roadmap on Hydrogen and Fuel Cells, urban areas have been separated into big cities with 500 000 inhabitants on average, and "average" cities, accounting for 25 000 inhabitants (Table 6). Rural areas are not specifically included within this analysis. Assuming that all rural areas all close to "average" cities, and trucked hydrogen will play a large role even in the more distant future, rural stations could be served when delivering hydrogen to the "average" city. The split into urban and non-urban population is based on the data provided by United Nations Statistics Division (Undata, 2012).

Hydrogen transmission

Transmission distances between centralised production and city terminals increase over time, reflecting the development from clustered stations towards nationwide coverage. Distances in the United States are slightly higher than in EU 4 and Japan, accounting for the generally lower population density.

All delivery options are used for hydrogen transmission in the model. Liquid hydrogen transmission is only used in the United States within the 2DS high H_2 , which results from a combination of higher hydrogen demand (due to larger FCEVs and higher annual mileages than within the other regions) and longer transmission distances.

Transmission of hydrogen via pipeline is the chosen option between centralised generation and the

high capacity terminals at big cities in all regions after 2030. These high capacity terminals also serve for the transmission of hydrogen to the “average city” (see Figure 16 in the Technology Roadmap on Hydrogen and Fuel Cells). By 2050, the total pipeline transmission network expands to between 8 000 km to 10 000 km within all three regions.

Hydrogen distribution

For inner-city distribution, city area is based on regionally different population density (taken from Demographia, 2011) and the assumed average population in big urban agglomerations and “average” cities. Estimates of the required distribution infrastructure are then calculated following the relationships to link urban area with distribution network length provided in Yang and Ogden’s 2007 paper (Yang & Ogden, 2007).

Due to much more sprawled cities in the United States, the inner-city distribution pipeline network in big cities is significantly higher than in EU 4. Due to the lower hydrogen demand in Japan (as a result of smaller FCEVs and significantly lower mileages), no pipelines are installed for hydrogen inner-city distribution at all within the 2DS high H₂.

Table 6 Disaggregation of urban areas

	<i>EU 4</i>	<i>Japan</i>	<i>US</i>
Number of big cities	80	100	66
Number of “average” cities	6 700	1 700	8 400
Transmission distance big city	50-100 km	50-100 km	50-150 km
Transmission distance “average” city	50 km	50 km	50 km

Source: IEA analysis

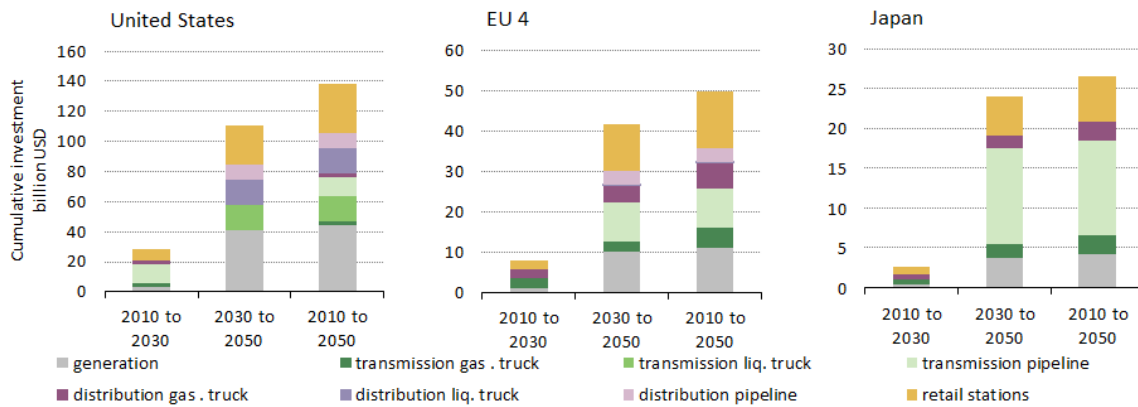
Cumulative investment in hydrogen generation, transmission, distribution and retail infrastructure

The cumulative investment costs for hydrogen generation, T&D and retail infrastructure until 2050 account for around USD 139 billion in the US, USD 50 billion in EU 4 and USD 27 billion in Japan (Figure 7).

Compared to EU 4 and Japan, hydrogen generation accounts for a higher share on total investment in the United States, which is mainly due to the higher per vehicle hydrogen demand. On the other side, in Japan, the share of transmission pipelines on total investment is much higher compared to the United States and EU 4. This is partly due to the higher concentration of population in big urban areas, which leads to a more concentrated demand and favours the use of pipelines. On the other side, the lower hydrogen demand per vehicle results in generally less hydrogen generation, T&D and retail infrastructure, which in turn leads to a more important share of pipeline infrastructure costs on total hydrogen generation, T&D and retail investment.

Altogether, in the 2DS high H₂, about USD 900 (EU 4) to USD 1 900 (United States) have to be spent on hydrogen generation, T&D and retail infrastructure for each FCEV sold between now and 2050.

Figure 7 Cumulative investment costs into hydrogen generation, T&D and retail infrastructure in the 2DS high H2 until 2050 for EU 4, Japan and the United States



Key point: Regional differences with regard to share of urban population, population density and vehicles use patterns affect the region specific investment needs for hydrogen generation, T&D and retail infrastructure

Annex A: 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 & 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	Gigaton
Kg	Kilogramm
Km	Kilometre
kW	Kilowatt
Lge	Litre of gasoline equivalent
MPa	Megapascal
Mt	Megaton
MW	Megawatt
MWh	Megawatt hour
TWh	Terawatt hour

Annex B: References

- Argonne National Laboratory - Nuclear Division (2010), *Technical Assessment of Compressed Hydrogen Storage Tank Systems for Automotive Applications*, Argonne National Laboratory, Lemont, IL.
- Bertoldi, P., Hirl, B., & Labanca, N. (2012), *Energy Efficiency Status Report - Electricity Consumption and Efficiency Trends in the EU*. Ispra: Joint Research Centre (JRC).
- Blum, L. et al. (2014), "Overview on the Jülich SOFC development status", 11th European SOFC & SOE Forum, Lucerne.
- Decourt, B. et al. (2014), *Hydrogen-Based Energy Conversion, More Than Storage: System Flexibility*, SBC Energy Institute, Paris.
- Demographia (2011), *Demographia World Urban Areas (World Agglomerations)*, 7th Annual Edition, April 2011, Belleville.
- EVI (2015), *Global EV Outlook 2015*, Electric Vehicle Initiative, Paris.
- ETSAP (2014), *Hydrogen Production and Distribution*, IEA Energy Technology Network - Energy Technology System Analysis Programme.
- 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, Giner Inc.
- Hydrogen Implementing Agreement Task 25 (2009), *Alkaline Electrolysis*, Hydrogen Implementing Agreement.
- IEA (International Energy Agency) (2007), *IEA Energy Technology Essentials*. Paris.
- IEA (2013), *Global EV Outlook: Understanding the Electric Vehicle Landscape*. Paris.
- IEA AFC IA (2014), IEA AFC IA Annex Meeting 25, IEA Advanced Fuel Cells Implementing Agreement, Trento.
- Iiyama, A. et al. (2014), "FCEV Development at Nissan", *ECS Transactions*, Volume 3, pp. 11-17.
- 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 (accessed 30 March 2015).
- Inoue, K. (2012), "Feasibility Study of CO₂ Free Hydrogen Energy Supply Chain Utilizing Australian Brown Coal Linked with CCS", submission to 12th Cryogenics Conference, September 2012, Dresden.
- Linde (n.d.), *Hydrogen*, www.linde-engineering.com/internet.global.lindeengineering.global/en/images/H2_1_1_e_12_150dpi_19_4258.pdf, accessed 30 March 2015.
- Liu, C. et al (2010), *Hydrogen storage in carbon nanotubes revisited*. Carbon 48, 452-455.
- National Renewable energy Laboratory (NREL) (2011), *Hydrogen production cost estimate using biomass gasification*. Golden.
- NREL (2014), *Hydrogen Station Compression, Storage and Dispensing - Technical Status and Costs*, National Renewable Energy Laboratory, Golden.

- NREL (2010), *Molten Carbonate and Phosphoric Acid Stationary Fuel Cells: Overview and Gap Analysis*, National Renewable Energy Laboratory, Golden.
- NREL (2010), *Molten Carbonate and Phosphoric Acid Stationary Fuel Cells: Overview and Gap Analysis*, National Renewable Energy Laboratory, Golden.
- NREL (2009a), "Scenario development and analysis of hydrogen as a large-scale energy storage medium", RMEL Meeting, National Renewable Energy Laboratory, Denver.
- NREL (2009b), *Scenario Development and Analysis of Hydrogen as a Large-Scale Energy Storage Medium*, National Renewable Energy Laboratory, Golden.
- National Research Council (2013), *Transition to Alternative Vehicles and Fuels*, National Research Council of the National Academies, Washington D.C.
- Nexant (2007), "Liquefaction and pipeline costs", Hydrogen Delivery Analysis Meeting, 8-9 May, Nexant, Columbia, MD.
- Sammes, N., Bove, R., & Stahl, K. (2004), *Phosphoric acid fuel cells: Fundamentals and applications. Solid State and Materials Science*, 372-378.
- Schaber, K., F. Steinke and T. Hamacher (2013), "Managing temporary oversupply from renewables efficiently: electricity storage versus energy sector coupling in Germany", International Energy Workshop, Paris.
- Stolzenburg, K. et al. (2014), *Integration von Wind-Wasserstoff-Systemen in das Energiesystem – Abschlussbericht*, PLANET Planungsgruppe Energie und Technik GbR.
- Toyota (2015), 2016 Toyota Mirai Fuel Cell Sedan Product Information, <http://toyotaneews.pressroom.toyota.com/releases/toyota+mirai+fcv+future+nov17.htm>, accessed 7 April.
- Toyota (2015a), Toyota Mirai Performance, <http://toyota.jp/mirai/performance/>, accessed 5 May.
- Undata, <https://data.un.org>. Retrieved March, 2012, from https://data.un.org/Data.aspx?q=urban+population&d=WHO&f=MEASURE_CODE%3aWHS9_96
- US DOE (2012), *Fuel Cell Technologies Program Record*, US Department of Energy, Washington, D.C.
- US DOE (2011), *Energy Hydrogen and Fuel Cell Program Plan*, US Department of Energy, Washington, D.C.
- US DOE (2010a), *Hydrogen Program 2010 Annual Progress Report - Innovative Hydrogen Liquefaction Cycle*, US Department of Energy, Washington, D.C.
- Vridity Energy/PJM Interconnection LLC (2014), *PJM frequency regulation in the PJM power market*. Philadelphia.
- Yang, C. and J. Ogden (2007), "Determining the lowest-cost hydrogen delivery mode", *International Journal of Hydrogen Energy*, pp. 268-286.