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Hydrogen-Based Energy Conversion

More than Storage: System Flexibility. Focus on Power-to-Gas

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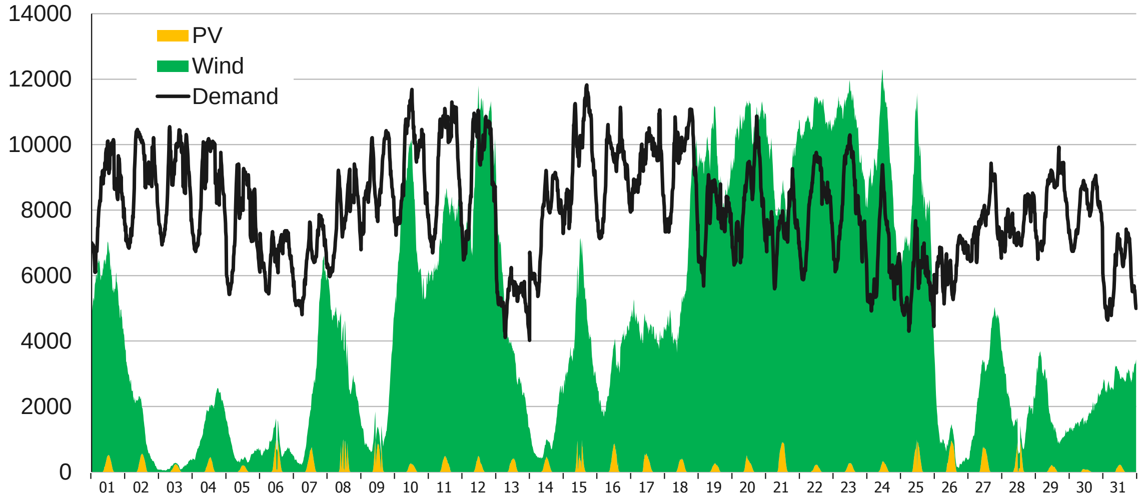
Background

Since the 2000s, onshore wind and solar photovoltaic [PV] technologies have grown exponentially. While wind and solar PV still represent a limited proportion of the global power mix (around 7% of installed capacity and 3% of power generated), their share in some regions is significant and deployment is expected to continue at a strong pace.

WIND & SOLAR GENERATION VS. DEMAND IN NORTHERN GERMANY
MW, December 2014 on the 50Hertz Operated Grid



Note: [1](1) Output is variable on multiple timescales, depending on daily or seasonal patterns and on weather conditions. (2) This variability makes long-term forecasting difficult and certainly less predictable than output from conventional technologies. (3) Wind and solar output are subject to ramp events

Source: SBC Energy Institute Analysis based on 50Hertz data archive (Wind and Solar Actual In Feed 20124, Control Load 2014).

Wind and solar PV are unique in the power-generation technology landscape because of the intermittent nature of their output. Their electricity production is variable, largely uncontrollable and hard to predict, while the most favorable locations for generating variable renewables are often far from consumptions centers. They make demand-supply matching more difficult since they increase the need for flexibility within the system, but do not themselves contribute significantly to flexibility.

Even if flexibility management can be optimized, for instance by refining the design of power systems, additional flexibility will be needed in the form of demand-side participation, better connections between markets, greater flexibility in baseload power supply and electricity storage.

Electricity storage is not new. In 2012, an estimated 128 GW of storage power capacity was installed around the world. However, 99% of that was pumped hydro storage [PHS]. All other technologies are at earlier stages of development and still have to demonstrate their commercial potential. However, not all electricity storage technologies are in direct competition with each other, as they may be designed to provide different types of storage service. For bulk-storage applications, there are three main options: PHS, compressed air energy storage [CAES], and hydrogen-based energy storage.

There are two reasons to store electricity: first, to provide back-up power for times when intermittent renewables are not producing energy; and second, to make use of surplus supply, reflected in low power prices or curtailments in wind power, both of which have occurred in various regions in recent years. Surplus is likely to be the major driver for bulk-storage technologies, since it results in low electricity costs.

The increasing use of wind and solar PV is bringing the potential and limitations of existing storage applications into sharp focus. Hydrogen-based storage technologies may be an interesting way of absorbing peaks in renewable electricity supply and avoiding the wastage of large quantities of renewable power, especially when natural sites for pumped hydro storage are not available or already occupied.

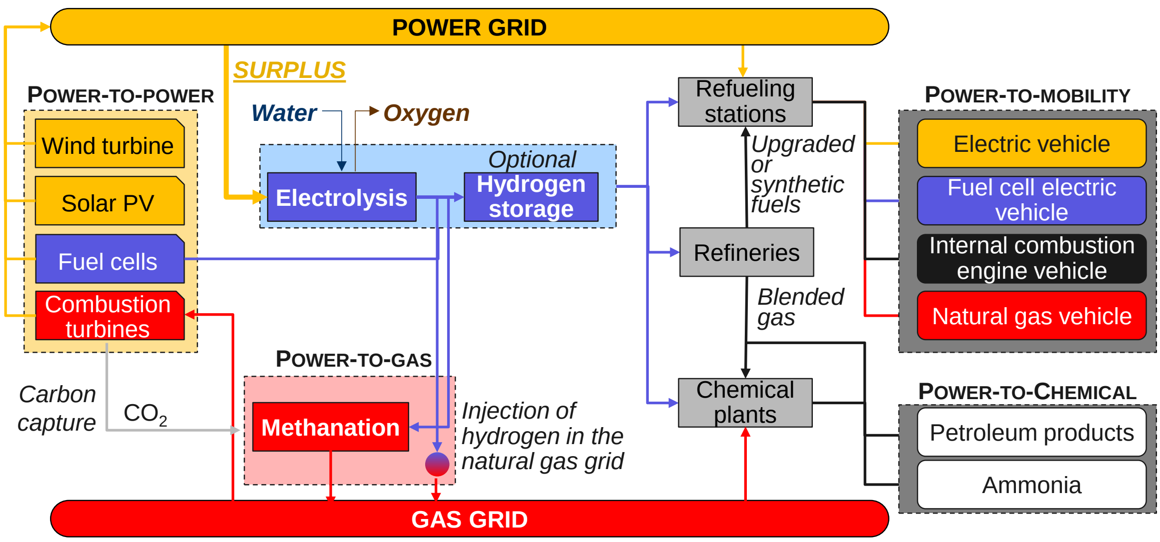
Hydrogen energy storage solutions are based on the electro-chemical conversion of electricity into a new energy carrier, hydrogen, by means of water electrolysis, in which water [H_2O] is split by an electric current into its constituent elements, (di)-hydrogen [H_2] and oxygen [O]. Exploiting hydrogen's versatility, chemical energy storage opens up alternatives to the usual approach to electricity storage.

First, time. Although the volumetric energy density of hydrogen is inferior to those of hydrocarbons, it is superior to those of other bulk-electricity-storage technologies. It is the only technology capable of compensating for several weeks of windless or cloudy conditions and of guaranteeing security of supply to the same degree as stocks of oil.

Second, location. Hydrogen-based technologies could reduce infrastructure investments required for integrating intermittent generators into the grid. Converting electricity produced from renewables into hydrogen allows existing infrastructure to be leveraged: power networks by locating storage facilities at congestion nodes to level the load; gas networks (in a process known as power-to-gas); and hydrogen transport options (*e.g.* pipelines, road transport on truck-trailers etc.).

Third, application. The versatility of hydrogen-based storage solutions, compared with other electricity-storage technologies, means they are not restricted to providing electricity back to the grid, using fuel cells or combustion turbines. Hydrogen can be used in its traditional markets, as an upgrader in refineries or as a commodity in many industrial processes. Hydrogen can also be used as transport fuel, directly, in fuel cell electric vehicles [FCEV], it can be blended with natural gas to fuel compressed natural gas vehicles and it can even be used as a feedstock for producing synthetic fuels. Finally, it can play an important role in decarbonizing end-uses of heat through power-to-gas concepts.

FIGURE 2: SIMPLIFIED VALUE CHAIN OF HYDROGEN-BASED ENERGY CONVERSION



Note: Simplified value chain. End uses are non-exhaustive. Note that the power and gas grids are the main supplier to the residential and commercial end-uses (lighting, heating and cooling, cooking…)
Source: SBC Energy Institute analysis

Aim

The SBC Energy Institute (SBC-EI) initiated this study as part of its analysis of intermittent electricity and enabling technologies. Having made the case for hydrogen-based conversion solutions, the SBC-EI concentrated on sub-technologies. The objective was to view the hydrogen industry through a technological prism, revealing barriers to progress and providing stakeholders – be they policy-makers, energy professionals, investors or students

– with the tools needed to understand a complex and often misunderstood sector. The study summarizes and assesses nine business cases for hydrogen, based on academic literature and research. The SBC-EI also dedicates a chapter to environmental impacts, and safety and social-acceptance issues. As a result of hydrogen's long history of safe industrial use, hydrogen professionals tend to underestimate the negative nature of the public's perception of safety. However, overcoming the public's doubts is, and will remain, a prerequisite for hydrogen development beyond chemicals and petrochemicals facilities

Methods

The SBC-EI's exhaustive techno-economic analysis of the entire value chain, from power conversion to end-uses of hydrogen, involved: an extensive review of the literature; more than 50 interviews with a variety of hydrogen-industry stakeholders including Air Liquide – Areva – Argonne National Laboratory – Audi – Bloomberg New Energy Finance – Conduit Ventures – Electrochaea – Enbridge – Energy research Center of the Netherlands – European Association for Storage of Energy – European Commission Joint Research Center – Etogas – Fuel Cell & Hydrogen Joint Undertaking – GDF-Suez – GrDF – GRTgaz – HarbourVest Partners, LLC – Hinicio – Horizon Fuel Cell – Hydrogenics – International Energy Agency – ITM Power – Jochen Marwede – Krajete – Leo Roodhart – Linde – McPhy – RWE – Shell – Siemens – UK Technology Advisory Board.

The outcomes are summarized in an abstract and in a short presentation, and covered in detail in a slide-based FactBook. These resources are all available for download to the public and have been reviewed by: Amgad Elgowainy, principal energy systems analyst at Argonne National Laboratory; Marcel Weeda, manager, hydrogen transitions and infrastructure at the Energy research Centre of the Netherlands; and Alexander Körner, lead author of the Hydrogen Technology Roadmap at the International Energy Agency.

Finally SBC-EI's findings have been presented in keynote speeches to leading conferences, such as the 20th World Hydrogen Energy Conference held in Gwangju (Korea) in 2014.

Results

Converting intermittent electricity into hydrogen by means of water electrolysis is the main economic and technological challenge for hydrogen-based electricity storage.

Cost-effective electrolysis is the missing link in the hydrogen-conversion value chain. Although continuous-load water electrolysis is a mature technology, the need for electrolysis systems to withstand variable loads requires significant flexibility and this has changed the game.

The need for flexibility is making proton exchange membrane [PEM] technology a popular alternative to alkaline systems. The latter is currently the lower-cost option and the only practical solution for large systems, but it suffers from its limited ability to respond to load changes and from a complex design that offers limited cost-reduction potential.

Conversely, PEM is highly flexible and has a simple design. There will be considerable potential for cost reduction if the technology enters mass-production. The economics of PEM electrolysis would also benefit from a reduction in the amount of noble metal catalysts used. In addition, PEM cells can operate at higher current densities than alkaline cells and are, as a result, more compact; last, but not least, they can more easily supply self-pressurized hydrogen – limiting the need for hydrogen compression. Most manufacturers, including Siemens, Hydrogenics and ITM Power, are now betting heavily on PEM and the first megawatt systems have been completed in 2013.

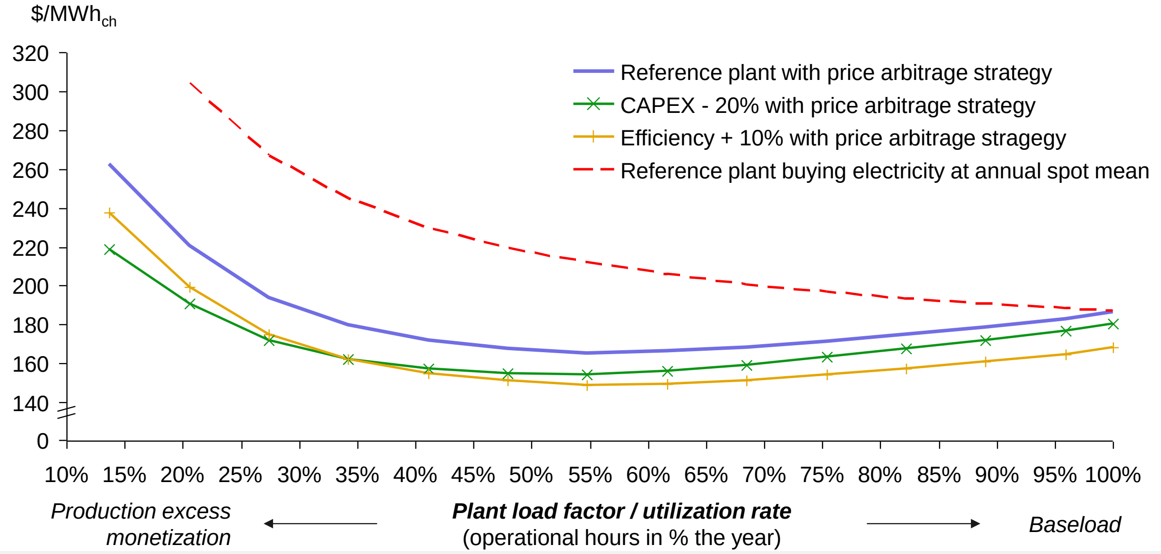
High-temperature solid oxide electrolyzer cells [SOEC] are a groundbreaking technology, at the R&D stage. SOECs can theoretically achieve unrivaled efficiency due to their ability to recover heat to supply the energy needed for electrolysis. Combined with the absence of noble metal catalysts and their simple design, these advantages are expected to lower capital costs per unit of capacity. SOECs also enable regenerative electrolysis (*i.e.* electrolysis with the ability to run in reverse mode) and the co-electrolysis of carbon dioxide and water. However, they will not be viable in the near term because of the relatively rapid degradation rate of their membrane and to their limited ability to withstand variable loads.

Electrolyzers cannot yet compete with conventional H_2-production processes, but their competitiveness may benefit from two features.

First, due to the modular nature of electrolyzer plants, the levelized cost of hydrogen [LCOH] is not significantly affected by plant size. Under prevailing market conditions and operated in baseload mode, decentralized production costs roughly 5% more than centralized production. If steam methane reforming [SMR] – the most common hydrogen-production technology – is being used to make hydrogen, then decentralized production costs twice as much as centralized production. Even though production by electrolysis is closer to competing with SMR in decentralized production, grid-connected electrolyzers are still generally unable to compete with SMR when operated continuously.

Second, discontinuous operation should reduce the LCOH by enabling the arbitrage of grid electricity price variations (using off-peak electricity prices where possible) and by generating revenues from power grid services (being rewarded for the ability to adjust electricity withdrawal upwards or downwards very quickly and on demand). At present, electricity price spreads on the spot markets are still too narrow to enable significant hydrogen-production cost reductions through price arbitrage. Indeed, the most important factor is how frequently low price events occur rather than how negative they can be at any one time.

FIGURE 3: LEVELIZED COSTS OF HYDROGEN FOR A GRID-CONNECTED ELECTROLYSIS PLANT



How to read this graph

The graph depicts the levelized cost of hydrogen [LCOH] production depending on how often electrolysis plant is used during the year. The electrolyzer is assumed to be connected to the grid. This create opportunities for price arbitrage (lowering the annual load factor of the plant so that it operates primarily during periods of low-cost electricity).

In this simulation, if price arbitrage could be realized perfectly, the LCOH would be reduced by 12% (blue curve *vs.* red curve). Optimal utilization rate is achieved when the plant is operated with a load factor of 55%.

Two alternative electrolyzer plants have been compared with the reference plant. The green and yellow curves simulate the effect of two potential improvement axis for electrolyzers: a decrease in capital cost of 20% and of an increase in its efficiency by 10%, respectively. One can notice that the optimal utilization rate is lower if CAPEX are decreased than if efficiency is increased: high efficiencies are useful for high load factors, while low capital costs are essential for highly discontinuous operations.

Note: Illustrative example based on 8.5MW$_{ch}$ electrolysis (5 alkaline stacks of 1.7MWch each), with total installed system CAPEX: $765/MWh$_{ch}$, Efficiency: 79%HHV, Project lifetime: 30 years and real discount rate after tax:10%.
Source: SBC Energy Institute Simulation based on US DoE H2A Model

Improving efficiency has long been the priority of electrolyzer manufacturers, since electricity costs are the main component of hydrogen-production costs in continuous-load electrolysis. Significant improvements in the electrochemical performance of electrolyzers have been made; PEM and Alkaline can now attain efficiencies of 78%. When utilization rates are low, investment costs become a greater consideration than efficiency.

The priority in the case of PEM technology is reducing manufacturing costs per cell area. Levers for cost reduction include (1) cell improvements (develop wider and thinner polymer membranes or reduce noble metal catalyst loadings); (2) stack improvements (reduce labor costs through mass production and new manufacturing techniques; and (3) plant improvements thanks to economies of scale. The priority for alkaline cells is increasing current densities, which will require the development of more durable materials, capable of resisting higher temperature.

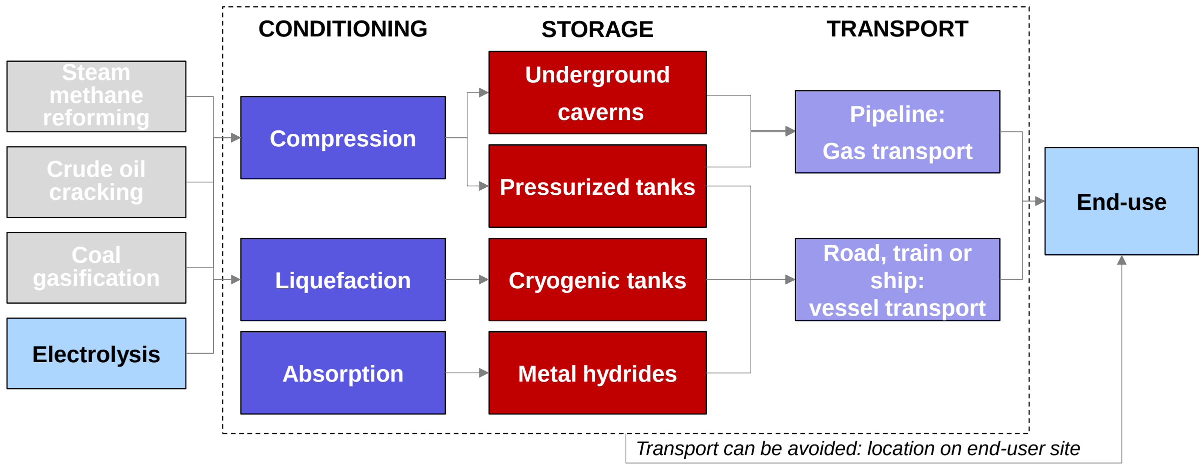
The main parameters that could help electrolyzer commercial viability are therefore, in decreasing order of importance: reductions in the capital costs of electrolyzers, the introduction of mechanisms to reward short-term grid-stability services or long-term storage services, and reductions in electricity input prices or greater electricity-price volatility. The ability to sell to valorize excess heat or by-produced oxygen locally will also have an impact.

The use of hydrogen storage and transport must be minimized in order to avoid cost and efficiency penalties incurred by initial conditioning.

Hydrogen storage and transport form the most mature segment of the chain, benefiting from the chemicals and petrochemicals industries' extensive experience of hydrogen utilization. The challenge is, first and foremost, economic. Due to hydrogen's very low volumetric energy density at ambient conditions, the volume of hydrogen gas produced by water electrolysis must be reduced in some way: compression, liquefaction (cooling to -253°C) or absorption into metal hydrides.

This initial conditioning step incurs energy losses of 5-15% in the case of compression (depending on pressure differentials), 25-45% during liquefaction, and 5-20% in the case of absorption into metal hydrides, varying according to heat-capture, storage and recycling capability. Conditioning also incurs additional capital costs. In order to minimize those costs, electrolyzers delivering self-pressurized hydrogen to end-user sites are likely to be the preferred option. Note that minimizing the handling costs of hydrogen is also of the main rationales behind power-to-gas.

FIGURE 4: HYDROGEN 'PACKAGING' OPTIONS BEFORE STORAGE AND TRANSPORT



Source: SBC Energy Institute

Even if its role is reduced, hydrogen storage will still be needed in most cases, at least to act as buffer along the value chain. The choice of storage type depends largely on the energy-capacity requirement and space constraints, but also on the desired operating cycling rate.

Pressurized tanks are likely to remain the main means of storing hydrogen. They are well suited to small- to mid-scale applications, safe thanks to years of experience, efficient and affordable, as long as the cycling rate is high. Underground storage in man-made salt caverns allows lower cycling rates and is the most competitive option for large-scale storage. However, bulk hydrogen storage seems unlikely to be needed in the near future and could suffer from limited geological availability; other than salt formations, reservoirs being considered for hydrogen storage are still at the early demonstration phase.

Liquefied hydrogen is, in many ways, ill-suited to electrolytic hydrogen storage. The large investment required for cryogenic facilities and the intensive use of energy in liquefaction are constraining the technology. However, since liquefied-hydrogen storage benefits from economies of scale and provides extremely pure hydrogen, it could play a role in the long-distance cryogenic transport of large quantities of hydrogen to refueling stations. Finally, metal hydrides may change the rules of the game for small-to-medium-scale applications in the medium term. Avoiding hydrogen compression or liquefaction is, in theory, very appealing. Yet the industry remains torn between optimism and caution when it comes to hydride storage. Its potential outside niche markets, where its safety and density are crucial advantages, remains to be proved.

Transport requirements must be considered because the choice of conditioning and storage constrains the type of transport that can be used. The choice of transport depends on transport distance, on hydrogen throughput and on the distribution of end users.

Road transport enables distributed delivery. The transport of compressed hydrogen in tanks is limited to short distances and low throughputs. Liquid hydrogen transportation may only be viable for large quantities delivered over long distances to numerous locations, most likely refueling stations. Finally, pipelines can provide a low-cost option for point-to-point delivery of large volumes of hydrogen. However, they lack the flexibility of road vehicles for distributed delivery. Furthermore, pipe-laying incurs significant up-front costs, which, in view of current demand for hydrogen, will inhibit the expansion of hydrogen pipelines.

The final configuration of a hydrogen system could include a mix of solutions, such as decentralized electrolysis located on end-user sites, with centralized production centers as back-up or to adjust for fluctuating demand for road deliveries.

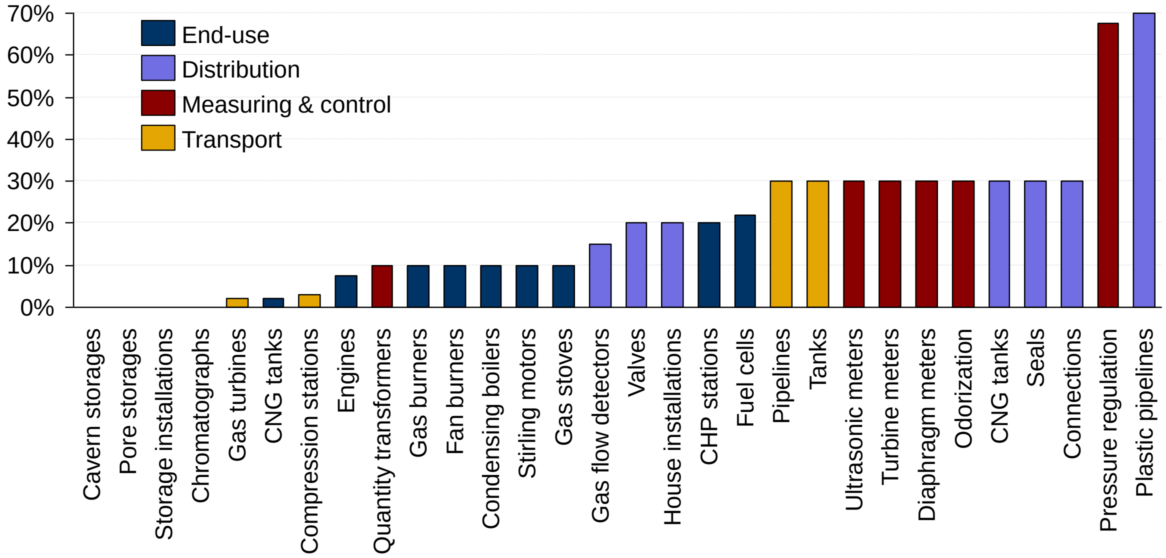
Power-to-gas is an elegant solution at the crossroads of networks and energy sources, but its economics remain highly uncertain.

Power-to-gas [P2G] was conceived as a way of using the gas grid to store renewable electricity. But, in practice, P2G does more than this. Its benefits include the "greening" of end uses of natural gas, such as heat generation; it also improves the flexibility of the energy system by pooling gas and power infrastructure. Power and gas grids can be linked in two ways: blending, which involves injecting hydrogen into the gas grid; and methanation – the conversion of hydrogen and CO_2 into methane, also known as synthetic natural gas [SNG].

Gas-distribution networks built to carry town gas, a mixture of hydrogen, carbon monoxide and methane, are familiar with transporting mixtures of methane and hydrogen. However, gas infrastructure and end-appliances have, since the creation of such grids, been designed to operate on pure methane, making the injection of H_2 problematic.

Three main constraints must be addressed: the integrity and safe use of pipeline and grid appliances; the energy capacity of the grid; and the sensitivity of end-use appliances to hydrogen/methane blends. The latter is likely to impose the greatest limitation. In general, the gas grid should tolerate 1-5% volume blending at any point of the network, and up to 20% in distribution pipelines with no critical downstream appliances (and not made of exotic materials).

FIGURE 5: LIMIT OF HYDROGEN BLENDING ALONG THE NATURAL GAS INFRASTRUCTURE
H_2 concentration uncritical (vol.%)



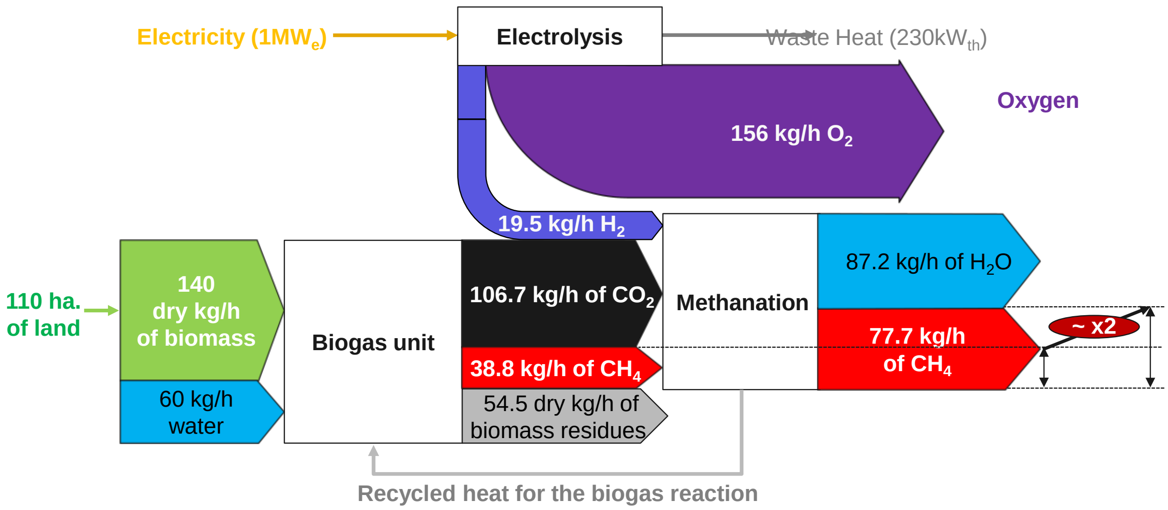
Note: CNG for compressed natural gas.
Source: Adapted from DVGW - German Technical and Scientific Association for Gas and Water (2013)

Even with such conservative assumptions, blending into the gas grid provides large short-term market for electrolytic hydrogen. This is due to the scale of the gas grid, which provides the energy equivalent of around 1,000 TWh both in the UK and in Germany. Hydrogen blending is a low-cost, early-stage solution for monetizing electricity surpluses in countries with a highly developed natural-gas infrastructure. In that situation, business models will depend to a large extent on the cost of hydrogen production by water electrolysis and on the existence of feed-in-tariffs for "green gas".

Despite incurring additional capital costs and energy losses – of 40% when heat is not recovered – methanation is considered a promising way of getting round blending-ratio limitations. However, due to the process's huge CO_2 requirements, it is constrained by the availability of affordable CO_2 sources. CO_2 capture from air is extremely energy intensive, resulting in an efficiency drop from 60% to 39%. As a consequence, methanation is mainly done by recycling large quantities of fatal CO_2.

For now, the best CO_2 sources are biomethane plants. This is partly because biomethane reactors produce raw biogas, which can be upgraded with electrolytic hydrogen instead of being purified, reducing energy losses by around 10%. In addition, the heat from methanation can be recycled to power the biogas unit, boosting the efficiency of biomethane production from 68.7% to 85.3%. This increases the ratio of methane output to biomass input by a factor of up to 2.5 and optimizes land use, which has societal benefits.

FIGURE 6: SIMPLIFIED MASS FLOW CHART OF HYROGEN-ENRICHED BIOMETHANE PLANT
kg/h



Note: Biomass feedstock is a maize silage of 5kWh$_{ch}$/kg of dry matter, cultivated with a land yield of 0.63MW$_{ch}$ per km²; The anaerobic digestion of maize silage requires heat and has an total efficiency of 68.7%; Thermochemical methanation at 300°C and 77.7% hydrogen-to-methane efficiency.
Source: SBC Energy Institute analysis

In the longer term, large P2G projects could source CO_2 from carbon-capture plants, and would work especially well with oxy-combustion capture technology because electrolysis also produces oxygen, which could be used in the oxy-combustion process.

There are two competing methanation processes: thermochemical catalysis and biological methanation. The former is likely to remain the preferred option in the short to mid-term; Etogas commissioned a 6 MW plant for Audi, in 2013, in Werlte, Germany. The latter, derived from anaerobic digestion processes of producing biogas, may become a viable alternative for distributed small-scale plants. Unlike thermochemical catalysis, biological methanation operates at low pressure. It is also more flexible (it has a quick start-up time) and more tolerant of raw gas impurities. Danish start-up Electrochaea completed a 250 kW demonstration plant in 2013 and has announced a 2.1 MW project to demonstrate upscaling, which is, as with any biological reaction, difficult to achieve.

Power-to-gas, whether it involves hydrogen blending or the manufacture of synthetic natural gas, will struggle to compete with natural gas on a calorific value basis. Hydrogen produced from electrolysis is currently too expensive, ranging from $120 to $500 /MWh, depending on the utilization rate and electricity prices. The levelized production costs of SNG are still uncertain because of a shortage of reliable data and are very sensitive to the utilization rate, capital costs and electricity prices. According to economic models produced by the proponents of methanation, even if there were a significant decline in investment costs ($1,200/MW including electrolysis, compared with $4,000 at present), it would not be competitive with natural gas for utilization rates below 50% and for average electricity prices above $40/MWh.

Unless customers are willing to pay a green premium and without a mechanism for integrating lower external costs, power-to-gas is unlikely to become competitive in the short term. However, methanation should be investigated as a solution for decarbonizing heating and mobility, and several countries are considering this option.

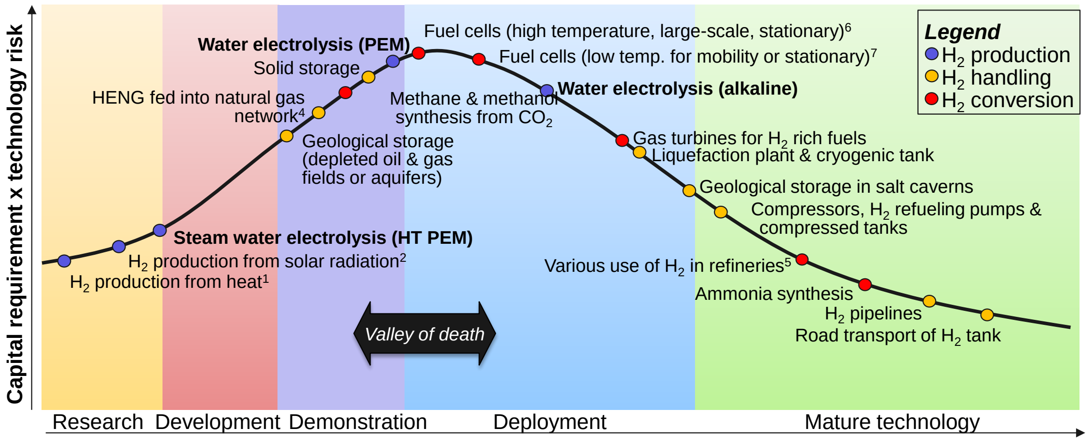
Conclusions

The value of hydrogen-based energy solutions lies predominantly in their ability to convert renewable power into green chemical carriers – hydrogen, methane, methanol or ammonia. In other words, hydrogen's value lies mainly in its versatility. More than just an energy carrier, hydrogen can act as a bridge between different branches of the energy-supply system – optimizing the use of energy generated from renewable power at the energy-system level while also utilizing chemicals infrastructure.

Applications of hydrogen-based conversion solutions are, in essence, system-specific. However, whatever the end-use and the energy system, the development of hydrogen-based solutions is subject to three pre-requisites: a greater penetration of variable renewables in the power mix; the reduction in the cost of electrolysis; and some kind of support from public authorities - in addition to the support to renewable power - in the near and medium terms.

Individual hydrogen-based technologies are now sufficiently proved to enable the establishment of large, integrated demonstration projects. These, however, are still largely locked in the investment "valley-of-death" – where technology is both expensive to demonstrate at full scale and its feasibility/profitability remain uncertain, although mid-scale demonstration projects exist in Europe. As a result, public and corporate funding remain essential

FIGURE 7: SIMPLIFIED MASS FLOW CHART OF HYROGEN-ENRICHED BIOMETHANE PLANT
kg/h



Note: [1]Nuclear or solar thermochemical water splitting; [2]Photolysis, photo-electrolysis or photo-biological water-splitting; [3]By thermochemical processes, principally: methane reforming, the cracking of petroleum fractions, and coal or biomass gasification; [4]HENG: Hydrogen-enriched natural gas; [5]Includes the upgrading of heavy/sour oil and the synthesis of synfuels from syngas (methanol, DME, MtG etc); [6]Includes SOFC, PAFC and MCFC; [7]Includes PEMFC and AFC.

Source: SBC Energy Institute analysis

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