Fuel cells and hydrogen
Joint undertaking

Development of Water Electrolysis in the European Union

Final Report

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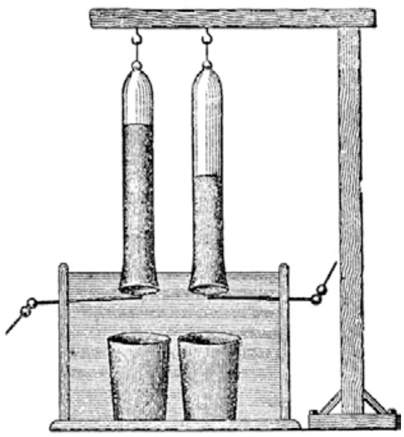

To ?

New Energy World JU
fuel cells & hydrogen for sustainability

E4tech Sàrl with Element Energy Ltd
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Authors	Luca Bertuccioli (E4tech) Alvin Chan (Element Energy) David Hart (E4tech) Franz Lehner (E4tech) Ben Madden (Element Energy) Eleanor Standen (Element Energy)

E4tech Sàrl
Av. Juste-Olivier 2
1006 Lausanne
Switzerland

Tel: +41 21 331 15 70
Fax: +41 21 331 15 61

Company number: CH-550-1024874

www.e4tech.com

element energy
Twenty, Station Road,
Cambridge, CB1 2JD
United Kingdom

Tel: +44 1223 852 499
Fax: +44 1223 353 475

Registered in England and Wales Reg. no. 4646003

www.element-energy.co.uk

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FCHJU Notice

The Fuel Cells and Hydrogen Joint Undertaking (FCHJU) is a unique public private partnership supporting research, technological development and demonstration (RTD) activities in fuel cell and hydrogen energy technologies in Europe. Its aim is to accelerate the market introduction of these technologies, realising their potential as an instrument in achieving a carbon-lean energy system.

Fuel cells, as an efficient conversion technology, and hydrogen, as a clean energy carrier, have a great potential to help fight carbon dioxide emissions, to reduce dependence on hydrocarbons and to contribute to economic growth. The objective of the FCHJU is to bring these benefits to Europeans through a concentrated effort from all sectors.

The three members of the FCHJU are the European Commission, fuel cell and hydrogen industries represented by the NEW Industry Grouping[1] and the research community represented by Research Grouping N.ERGHY[2].

Disclaimer

This report was commissioned by the FCHJU and prepared jointly by E4tech and Element Energy. E4tech and Element Energy are internationally leading consultancy firms with deep expertise in sustainable energy technology, strategy, and policy.

This report represents the two firms' best judgment in the light of information made available. The reader is advised that, given the wide scope of the project, not all information could be independently verified or cross checked and that some assertions in the report may therefore be based on a single source of information. Although appropriate use of the conditional tense is used to highlight the degree of uncertainty, the reader should understand that the use of, reliance upon, or decisions made based on this report, are entirely the responsibility of the reader. E4tech and Element Energy do not accept any responsibility for damages suffered by the reader based on the contents of this report.

[1] The NEW Industry Grouping, together with the European Commission, is a founding member of the Fuel Cells and Hydrogen Joint Undertaking. The NEW Industry Grouping is an association with open membership to any European based company with activities related to fuel cells and hydrogen. It has over 60 companies as members, representing a major share of Europe's hydrogen and fuel cell industries.

[2] N.ERGHY is an association with open membership to any European based research organisation with activities related to fuel cells and hydrogen. It has over 50 research organisations as members, representing the majority of European research in the field.

Contents

List of Figures

List of Tables

Executive Summary

Water electrolysis has been used industrially to produce hydrogen for more than a century. Once the favoured method for hydrogen production, it was subsequently largely displaced by lower-cost methods, such as steam reforming of natural gas, and today only 4% of hydrogen is produced this way. Interest in water electrolysis has increased again recently, influenced by its potential to provide hydrogen with a very low associated carbon footprint as well as for electrolysers to provide services, such as load response management, to changing electricity grids.

Demonstration projects are under way in which electrolysers are connected to electricity and gas grids, but significant gaps remain in the knowledge of what electrolysers can ultimately achieve, at what cost, and where they may be most effective in meeting policy and market needs. For the FCHJU to appropriately support the development and deployment of electrolysers for hydrogen energy applications, coherent data on a wide range of aspects will need to be gathered and interpreted.

By gathering and critically examining inputs from literature, electrolyser manufacturers and other stakeholders, this study shows that while the maturity of electrolysers in industrial applications is adequate, their maturity for energy applications is not only low but actually hard to assess. Techno-economic analysis carried out specifically for the study suggests that electrolysers could play a role in energy applications, and that in some cases they can directly compete with hydrogen produced from other sources. However, some of these cases require further development of electrolyser technology to achieve projected cost and performance targets, and even in favourable policy environments electrolytic hydrogen is frequently uncompetitive with hydrogen from other sources. Supplying hydrogen to remote customers; taking advantage of further support mechanisms such as green certificates or carbon taxes for hydrogen generated from renewable electricity; or providing additional services to grid operators are required to bring additional revenue streams and allow electrolytic hydrogen to compete.

The electrolyser industry, though industrially mature in some senses, is small and fragmented. Costs have not been driven down through mass production or supply chain optimisation, and room for technology improvement is still significant. The data gathered show agreement that capital costs could be reduced, lifetime and durability enhanced, and system efficiency raised through a variety of approaches. However, industrial actors are already able to achieve many of these key performance indicators in isolation. The techno-economic analysis shows that achieving them concurrently is more important. We therefore propose that research and development of approaches to reduce capital cost *while maintaining* lifetime and appropriately high efficiency be undertaken, rather than any measure individually.

Simultaneously maintaining and improving these key performance indicators requires much better knowledge of the future requirements of electrolyser systems. Current systems are designed for high efficiency at their operating design point, at typically close to 100% load, and to run continuously. Providing energy services is expected to require start-stop and dynamic operation and high efficiency across much of the load curve. Projects designed specifically to gather data on these operating parameters will be essential to allow both the correct design of future electrolyser systems and the right policy mechanisms to allow them to provide valuable services. A better understanding of the

wider boundary conditions affecting such service provision is also required, including available electricity tariffs and the size of energy services markets that may be addressed.

We therefore propose research priorities and a specific call that address these challenges. We believe further science and technology development are essential. We also think that for electrolysers to have the best chance of fulfilling their promise in the context of the FCHJU's objectives, development should be targeted at improving electrolyser system performance in energy applications. We therefore recommend research priorities that are based first around *energy system* metrics, then those of the *electrolyser system*, then specific *electrolyser technologies*.

Energy system research priorities include developing a better understanding of how electrolysers will need to interact with grids, and would be supported by the development of benchmark requirements, use cases, boundary conditions and standard operation and test cycles. Building an evidence base for defining supportive policy measures and for the anticipated size of future markets accessible by electrolysers is also important to quantify and direct appropriate support.

Electrolyser system priorities include demonstration projects to show exactly how systems will need to be developed to respond to the needs of their primary hydrogen customers, while fulfilling the additional services required to render them economic. As discussed above, designs allowing for stop-start, efficient part-load, and dynamic operation are expected to be essential for future competitiveness. In addition, a database of the different regulations, codes and standards that must be met in different jurisdictions and applications could support future measures to streamline permitting processes.

Electrolyser technology priorities are specific to the different chemistries under development. They respond to the need to reduce cost while maintaining or improving performance and include work on advanced catalysts and membranes as well as system engineering. Alkaline electrolysers are most mature, followed by Polymer Electrolyte Membrane (PEM) electrolysers. Other technologies include the anion exchange membrane ("alkaline PEM") and the solid oxide electrolyser. Each has promise for cost reduction and the solid oxide system, which operates at high temperature, could produce hydrogen with much lower electricity inputs than conventional electrolysers. Considerable development of solid oxide systems is still required, however, to demonstrate and prove their potential.

Given successful cost reduction and system performance improvements, electrolysers are expected to become more widespread in energy applications, with hundreds of installations leading eventually to hundreds of megawatts of installed capacity around 2020-2025. These improvements will of course proceed in step with the increased roll-out, each influencing the other.

To support the electrolyser industry and the related hydrogen energy value chain in developing suitable and competitive systems, we suggest a specific demonstration project call, in which at least two state-of-the-art electrolyser systems, in two different European countries, would be installed to provide hydrogen to an end-user and services to the electricity grid. It would be essential for information and learning from these systems to be disseminated as widely as possible.

1 Introduction

Water electrolysis plays a key role in almost all scenarios for the widespread roll-out of hydrogen for mobility, industry or energy storage. It is the dominant and most efficient route to hydrogen production from renewable electricity sources and hence the most proven of the options for generation of ultralow-carbon hydrogen. Electrolysis also has the added advantage of being very flexible, and hence potentially advantageous for electricity grids, where rapidly responding loads can meet the needs for a variety of grid services in a world of increasing intermittent renewable generation.

The FCHJU commissioned this study to better understand the conditions under which water electrolysers play a role in the energy system, and hence to allow revised technical targets for electrolyser technology and deployment to be established to 2020 and beyond. It was also designed to identify the technology gaps and barriers to deployment that could prevent those targets from being met and, based on these, propose priority research topics for RD&D for the FCHJU from 2014 to 2020.

The main inputs came from a literature review and stakeholder engagement process to gather technical and other data on electrolysers. Both academic and industrial organisations were contacted. The data gathered were fed into a techno-economic model which also had inputs on specific boundary conditions for the case studies under consideration. These were represented by countries with differing regulatory and energy boundary conditions. The model was used to analyse a range of use cases and compare the cost of hydrogen produced (frequently offset by the provision of additional services) with relevant counterfactual hydrogen production options.

The data gathering, stakeholder engagement and modelling were all used to identify and define both plausible and useful targets for research priorities in water electrolysis, primarily around the integration of electrolysers into energy systems applications. These priorities were elaborated into research topics and a specific draft call text was developed.

Nomenclature has proven to be important. Electrolysers are frequently cited as being able to provide ‘energy storage’ functions, and ‘power to gas’ is often mentioned as an opportunity. These descriptions are loose, and we have where appropriate used the term ‘grid services’ to describe the opportunities for electrolysers. These cover not only applications which are unambiguously energy storage, but also the feeding of gas into grids, and balancing services such as frequency response. We feel that this is important to allow both clearer understanding of the opportunity and to reduce the potential for constrained thinking.

2 The role of electrolysis in the future European energy system

2.1 The role of electrolysis today

Although originally hydrogen was produced by electrolysis, today the majority (48%) comes from reforming natural gas and refinery gas, as a by-product from chemicals production (30%) and from coal gasification (18%). Only about 4% of global hydrogen production (65 million tonnes) comes from electrolysis (IEA, 2007). The largest electrolysis plants (over 30,000 Nm^3/h) have historically been deployed for the fertiliser industry (Statoil, 2008). Apart from this industry, hydrogen from electrolysis is used in making other chemicals, food processing, metallurgy, glass production, electronics manufacturing and power plant generator cooling.

However, industrial hydrogen from electrolysis is not destined for specific industry segments but used where it is cost-effective. For example, hydrogen in the food industry in eastern Canada may come from electrolysis because of the very large plants in Quebec powered by hydroelectricity, but hydrogen for the food industry in Europe will almost certainly come from steam reforming of natural gas.

Today, only small amounts of hydrogen from electrolysis are used in energy applications, in sustainable transport programmes, in renewable energy storage, and in some other cases. These cases often benefit from hydrogen produced near the point of use, which is something that electrolysers can offer. However, these energy uses are geographically fragmented, and largely dependent on policy incentives. An emerging sector is that of ‘power to gas’, where electrolysers are being tested in pilot stations for integration between renewable electricity generation and the production of alternative energy carriers such as hydrogen or synthetic methane, which ultimately enable greater utilisation of renewable power. Globally about 50 such demo plants have been realised or are in the planning stage, and more recent projects are often larger than one megawatt of electrolyser electrical load (Gahleitner, 2013). Those pilot projects are often driven by the interest of power utilities and other actors in the value chain looking to better understand the potential and challenges of this technology, and who are looking to gain specific experience with electrolyser operation, plant siting, permitting, and regulations, as well as with power and gas grid connections.

2.2 Summary of stakeholder views on the role of electrolysis in the future energy system

Based on the stakeholder consultation there is general agreement that electrolysis will play an important role in the future energy system. New uses of electrolytic hydrogen in transport and energy storage are expected to outgrow traditional industrial use, although there are different views as to when this point will be reached.

The stakeholder consensus is that electrolytic hydrogen use is expected to gradually evolve from limited industrial exploitation today, through early energy and transport uses around 2015, to wide deployment in hydrogen refuelling infrastructure around 2020. Views on energy storage related deployments (e.g., power to gas) and industrial uses vary among stakeholders, but in general energy storage related applications are expected to grow significantly only after 2020. It is widely accepted

that this growth will depend on the evolution of the energy system and of regulatory frameworks. The views expressed by stakeholders are synthesised in Figure 1.

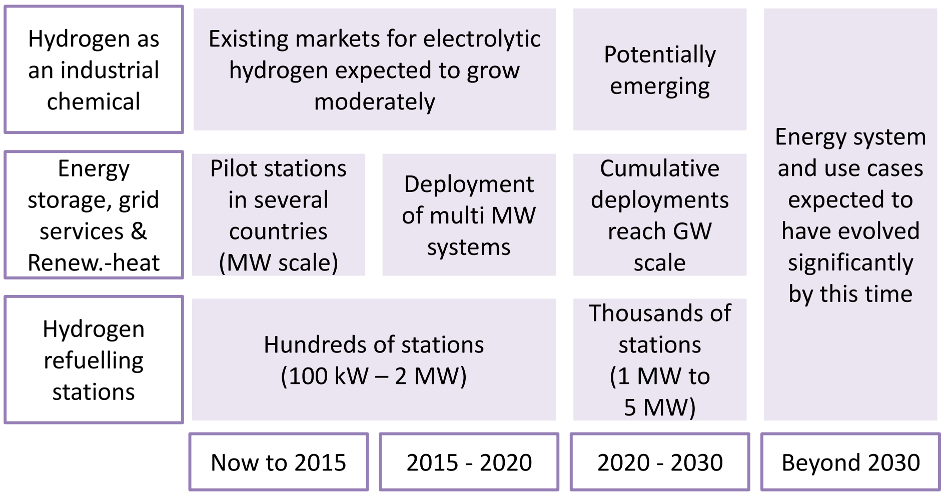


Figure 1: The changing role of electrolysis as reported by stakeholders

Transport-related electrolyser sales are expected to serve as a transition path for the industry to gradually get from the current 'made-to-order' business to a stage where higher volume production is typical. Demand for larger systems, e.g., up to 5 MW at large bus depots, is also expected. This should help to advance technologies such as PEM and AEM, currently not available at this scale.

While there is wide agreement on the importance of hydrogen refuelling in the near future, it is worth noting that views on deployments in energy storage applications vary depending on the group of stakeholders consulted. Research institutes often see more uncertainty in future deployment rates, whereas some electrolyser manufacturers see energy storage as an important market by 2020. One explanation for this discrepancy is simply their viewpoint, given the small size and fragmented nature of the electrolyser industry today. Even if electrolysis for energy storage is still in a (growing) field demonstration phase by 2020, this would likely represent a significant increase in business for the manufacturers. Also consulted were utility companies, currently investing in pilot and demonstration plants for 'energy storage' systems in order to assess the potential of electrolysis to provide services for the future energy system. The continued activity of utilities in this field is expected to depend on the outcomes of those pilot and demonstration projects.

2.2.1 Electrolysis in transport applications

At the European level, the establishment of alternative fuel infrastructure, including hydrogen, is seen as a priority. About 120 hydrogen refuelling points have been deployed across different countries to date (EC, 2013), while several member states have set national targets for the deployment of hydrogen infrastructure. Similar deployment efforts can be observed in parts of the United States (e.g., California) and Japan. The global car industry plans to roll out fuel cell electric vehicles in Europe from 2015 onwards.

It has been proposed to include hydrogen refuelling infrastructure targets for 2020 in the Directive on the deployment of alternative fuels infrastructure (EC, 2013). Although some uncertainty remains, several hundred hydrogen refuelling stations are expected to be deployed between today and 2025[3].

Whether this will create demand for *electrolysers* is not yet clear. Some early hydrogen refuelling stations are equipped with on-site electrolysers for hydrogen production. However, other sources of hydrogen, such as steam methane reforming (SMR) or the off-gases of industrial processes such as chlor-alkali, may be more cost-effective. Which source is better suited or more commercially viable for each refuelling point will depend on the local circumstances.

A number of stakeholders expect that mandates will require a certain share of renewable hydrogen at refuelling stations. Such mandates are currently already in place in California where at least one-third[4] of the hydrogen at refuelling stations is required to be 'green'. Such a mandate would favour the deployment of electrolysis and other low carbon routes to hydrogen (bio-hydrogen, by-product-hydrogen). Similarly, the UK H2 Mobility initiative put forward a roadmap with a 51% share of electrolytic hydrogen by 2030 (UK H2 Mobility, 2013).

2.2.2 Electrolysis for energy storage and grid services

In view of high renewable electricity targets in some regions, electrolysis is seen by many stakeholders as an element to address the potentially increasing challenges of integrating intermittent renewables. Electrolysers would operate when electricity generation is in excess of demand, or available at very low prices (e.g., during periods of high solar irradiation), thereby avoiding or reducing the need to curtail renewable electricity generation. The produced hydrogen could then be stored locally, or fed into the natural gas infrastructure, and be used in transport, heating or for re-electrification in power plants. Hydrogen production via electrolysis is often broadly classed as energy storage, irrespective of the final use of the hydrogen. As no formal definition exists, we have chosen a comparatively narrow definition of energy storage for this report, only covering those applications where the electrolyser usage profile is primarily designed to shift energy system loads in time, often across markets. So, for instance, an electrolyser that is only operated on excess renewable electricity would be considered energy storage, whereas one at a refuelling station nominally operating 8,760 hours per year would not.

Because they will need to respond to intermittent and fluctuating renewable power generation, the ability to operate dynamically is often cited as a key requirement for electrolysers to play the role above in high renewables energy systems.

A number of electrolyser operating strategies can be used to help balance supply and demand. Different strategies, which may be combined, have been suggested by stakeholders:

- *Limiting operation to times of excess or low cost renewable power generation*, which is expected to result in load factors of a maximum between 2,000 and 4,000 hours per year in 2050. This would require a system design optimised for efficient stand-by modes and would favour low capital cost over high efficiency.

[3] The "H2 Mobility" initiative (including Air Liquide, Daimler, Linde, OMV, Shell and Total) plans to deploy 400 stations by 2030 in Germany alone (H2 Mobility Initiative, 2013)
[4] Section 43869 (a)(2)(A) of the California Health and Safety Code

- Taking part in the markets for operational reserves (i.e., load shedding in case of grid incidents). This would require a system design optimised for quick response and start-up times.
- *Taking advantage of highly fluctuating electricity prices*. This would require a system design able to operate at a wide range of part loads, with highest efficiency at low part loads (operating at full load at suboptimal efficiency when electricity prices are low, operating at low part load with highest efficiency when electricity prices are high).
- *Allowing flexibility on very constrained grids*. In regions (such as islands) where high penetration of renewables has already been achieved, the use of hydrogen as an alternative energy vector to electricity may be beneficial.

It is important to note that while these different operating strategies (and the system performance characteristics that they imply) are being looked into by stakeholders and tested at pilot and demonstration plants, the industry is currently rather uncertain as to which of the requirements will ultimately be valuable in a future energy market, and FCHJU support could prove valuable in helping define these characteristics.

2.2.3 Electrolysis in the chemical industry

Consulted stakeholders do not expect hydrogen from electrolysis to compete as a basic industrial chemical with hydrogen produced from SMR. This is simply due to the lower value of base chemicals compared to transport fuels, where significantly higher prices can be achieved.

However, a number of stakeholders mentioned that use of hydrogen in the chemical industry in the near term may present lower barriers (such as the need to deploy infrastructure) than the use of hydrogen in energy-related applications. This may therefore offer opportunities for electrolysers. As an example, a German consortium including the chemical industry has investigated the potential for use of 'wind hydrogen' as a base chemical, and proposed to include this pathway in a strategy to deploy power to gas facilities (ChemCoast, 2013).

3 Status and outlook for electrolysis technology

3.1 Overview of electrolyser technologies

Three different types of electrolyser technology are currently available as commercial products, namely conventional alkaline electrolysers (liquid electrolyte), Proton Exchange Membrane (PEM) electrolysers and most recently also anion exchange membrane (AEM, also known as alkaline PEM[5]) electrolysers. Historically, alkaline electrolysis has dominated the market and accounts for nearly all the installed water electrolysis capacity worldwide. PEM electrolysis has been commercial for close to 10 years, whereas AEM appeared on the market only very recently. In Table 1, the characteristics of the three technologies are summarised.

[5] with PEM standing for Polymer Membrane Electrolyte

		Alkaline	PEM	AEM
Development status		Commercial	Commercial medium and small scale applications (≤ 300 kW)	Commercial in limited applications
System size range	Nm^3_{H2}/h	0.25 – 760	0.01 – 240	0.1 – 1
	kW	1.8 – 5,300	0.2 - 1,150	0.7 – 4.5
Hydrogen purity [6]		99.5% – 99.9998%	99.9% – 99.9999%	99.4%
Indicative system cost	€/kW	1,000-1,200	1,900 – 2,300	N/A

Table 1: Overview of commercially available electrolyser technologies

Although no products based on solid oxide electrolysis (SOE) technology are available, the concept has been proven by development and operation of short stacks[7]. We include this technology with respect to research activities, its claimed potential to significantly reduce costs and increase efficiencies, and its anticipated potential to become commercially available by 2020. Solid oxide electrolysers operate at significantly higher temperatures than alkaline, PEM and AEM electrolysers, typically 500-850 ^{o}C. As in Solid Oxide Fuel Cells (SOFCs), ceramics are used as a solid electrolyte which is stable at high temperatures. Technical advantages of SOE commonly claimed by researchers and developers are:

- Potentially higher electrical system efficiency compared to low temperature technologies, as (dependent on the temperature) a significant share of the energy input can be provided in the form of heat (e.g., waste heat).
- Potential use for co-electrolysis of both steam and CO_2, producing syngas, from which hydrocarbons such as liquid fuels can be produced.

3.2 Key performance indicators

This section provides an overview of the status and expected development of key performance indicators of electrolysis systems. The data provided is a synthesis of recently (2010-2013) published literature reviews (Smolinka et al., 2011; Mathiesen, 2013; Carmo et al., 2013; planSOEC, 2011), presentations, US DoE progress reports on electrolysis, manufacturers' data sheets, as well as original data gathered from manufacturers. Through stakeholder consultation, we have constructed trend lines to capture the developments broadly expected by experts and manufacturers. We term these key performance indicator-specific trend lines as *central case* KPIs in this report. The range of expected developments is bounded by a more optimistic (*best case* KPIs) and a more conservative (*worst case* KPIs) outlook.

[6] As per manufacturer data sheets, excluding optional (additional) purification stages. Note: This includes any non-optional purification stages within the system boundary described in data sheets.
[7] A stack consisting of a few cells only (typically 5 to 50 stacked cells). Short stacks are often used for testing and demonstration at lab scale.

3.2.1 Electrolyser system definition and key performance indicator overview

Key performance indicators are compared on the basis of a typical electrolyser system, including the system components depicted in Figure 2, rather than on a component or sub-system basis. This is in order to compare the different technologies on a more even footing. It is worth noting that despite the definition of the system boundary for this study, manufacturers often use different interpretations and are not always able to provide efficiency and cost data corresponding to exactly the same system boundaries. In addition, system pressure levels differ by product and manufacturer.

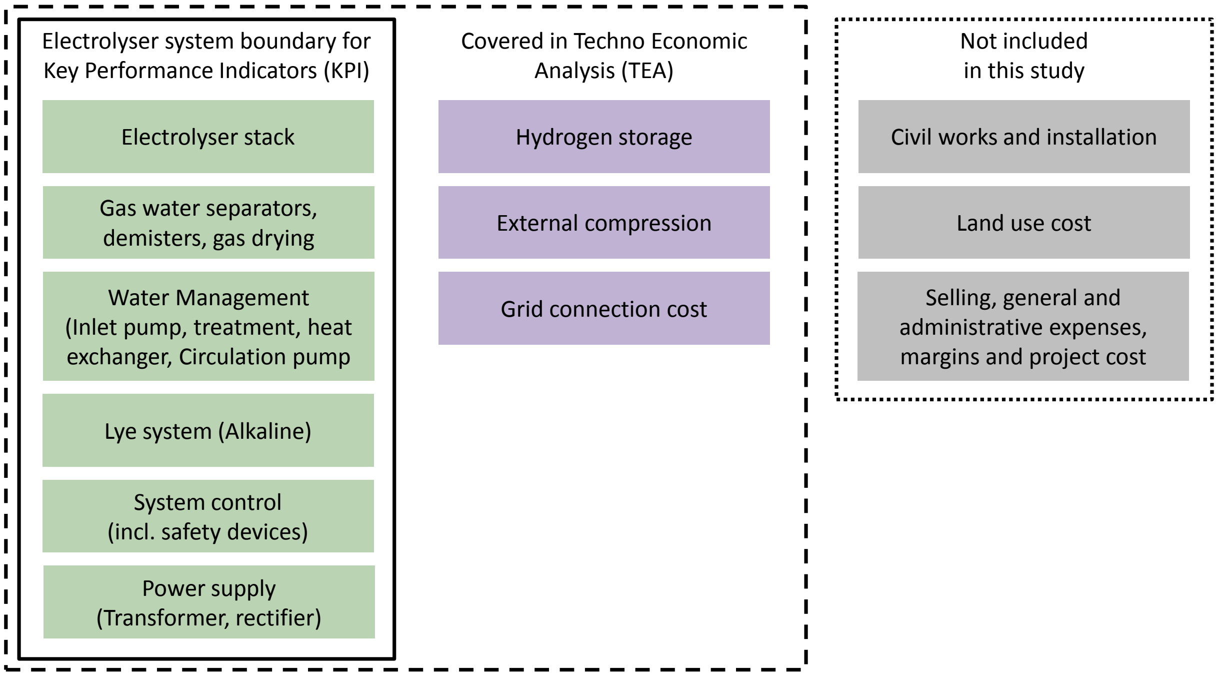


Figure 2: System boundaries for key performance indicators and techno-economic analysis

Any cost advantage of pressurised hydrogen output from an electrolyser is taken into account in the techno-economic analysis (TEA) through a reduced or eliminated external compression cost. Hydrogen storage and grid connection costs, depending on the voltage level at which the electrolyser is connected, are also covered in the TEA. Because of their very wide variation by country and region, neither civil works and installation nor land-use related costs are included in the analysis. The potential advantage of compact system designs, with small footprints, has been mentioned by manufacturers with respect to installations at space-constrained refuelling stations, but could not be quantified in this study.

The purity of hydrogen produced also varies between systems from different manufacturers and by technology. For alkaline electrolysers it may be necessary to clean the hydrogen of contaminants derived from the liquid electrolyte. Also, achieving very dry hydrogen (e.g. 5 ppm H_2O as specified in the SAE J2719 Norm) for hydrogen for fuel cells in transport applications can add significant purification demands. Technically these low water levels are required if the produced hydrogen is compressed using a metal membrane compressor technology. However, since purification requirements additional to those provided by state of the art electrolysers cannot be generalised by

application, but rather depend on the choice of compression technology, no external purification equipment or costs have been included in the analysis[8].

Key performance indicators can be selected and defined at many different technology levels (material, component, stack, system etc.). Following discussion with stakeholders and analysis we have chosen to evaluate them, as far as possible, at system level. This is in part to allow different technologies to be compared as fairly as possible, but also because some of the key performance indicators that have a significant effect on the TEA may be met using different technology development pathways, manufacturing and operating strategies.

We therefore focus on the following key performance indicators:

- Efficiency and lifetime
- Capital cost
- Pressurisation
- Equipment size
- Operating cost
- Dynamic and flexible operation

3.2.2 Efficiency, lifetime and voltage degradation

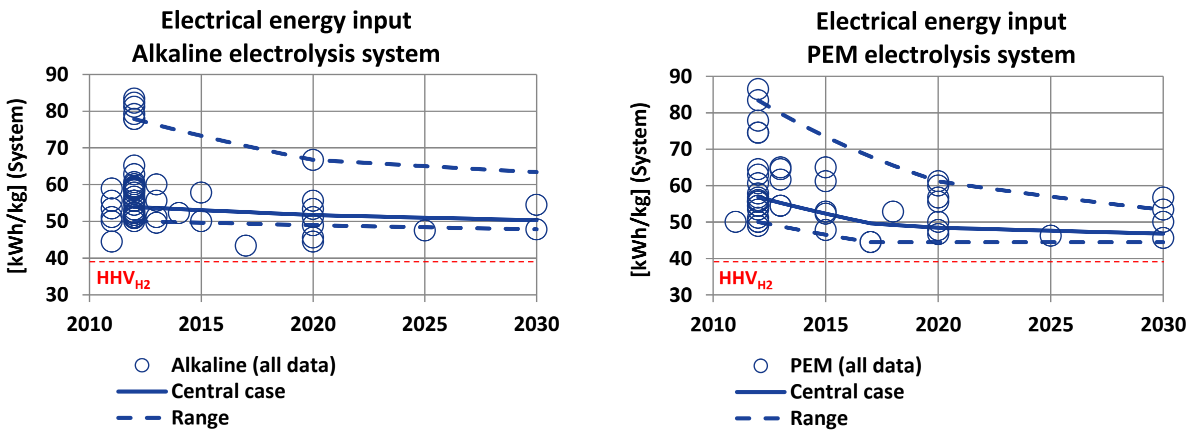
The efficiency of an electrolyser system can be hard to define exactly and especially hard to compare between different system designs and operating strategies, as it depends not least on operating points, boundary conditions and parasitic power requirements. Here, we describe 'efficiency' as *energy input in kWh per kg of hydrogen output*. For commercial technologies (alkaline, PEM, AEM) this energy is supplied in electrical form, with a theoretical minimum electrical energy input of 39.4 kWh/kg_{H2} (HHV of hydrogen), if water is fed at ambient pressure and temperature to the system and all energy input is provided in the form of electricity. The required *electrical* energy input may be reduced below 39.4 kWh/kg_{H2} if suitable heat energy is provided to the system. High temperature electrolysis, such as PEM steam electrolysis and particularly solid oxide electrolysis could have lower operating costs if the electrolyser were co-located with a low cost or waste heat source, than if all the energy were provided through electricity.

Low temperature electrolysers (<100°C) deployed in the twentieth century in the fertiliser industry were already optimised for high electrical efficiency at full load, to provide the lowest possible operating cost under continuous operation. State of the art systems can reach electrical energy inputs close to 50 kWh/kg_{H2}[9]. Those systems typically operate at low current densities (0.2 A/cm²) which aid the achievement of high efficiencies. If systems are instead optimised for low capital cost, higher current densities (which reduce the required surface area, the materials, and thus the cost) are typically used and higher electric energy inputs are accepted. The range of electrical efficiencies for contemporary electrolysers depicted in Figure 3 therefore represents different application optimisation goals.

The long term targets for electrical efficiency in low temperature electrolysis reported in literature and by stakeholders are broadly in the range of what has already been achieved. This does not however mean that development effort related to efficiency improvement has stopped. Optimising

[8] Except the standard drying equipment listed in Figure 2
[9] In classical terms, this corresponds to an LHV efficiency of 66% (79% HHV)

efficiency in lower-cost systems, e.g., those with high current densities, is widely mentioned as a focus area for research and development.



Electricity input [(1)]			Today	2015	2020	2025	2030
kWh_{el}/kg_{H2}	Alkaline	Central	**54**	**53**	**52**	**51**	**50**
		Range [(2)]	50 - 78	50 - 73	49 - 67	48 - 65	48 - 63
	PEM	Central	**57**	**52**	**48**	**48**	**47**
		Range [(2)]	50 - 83	47 - 73	44 - 61	44 - 57	44 - 53

[(1)] at system level, incl. power supply, system control, gas drying (purity at least 99.4%). Excl. external compression, external purification and hydrogen storage

[(2)] some outliers excluded from range

Figure 3: Electrical energy input (efficiency) trend lines for alkaline and PEM electrolysers

The efficiency points above are given as nominal efficiency at full load, which is the typical design point for a commercial electrolyser today. However, electrolysers are inherently more efficient at lower loads (down to a point), and some systems are optimised for part-load, with an ability to ramp up to full load for a period of time. For many of the energy applications expected in the future and analysed in the TEA, high efficiency across the load curve is important, to take advantage of fluctuating inputs. Such optimisation will require not only materials and component development, but also system optimisation, including the minimisation of stand-by power and parasitic loads such as pumps and inverters. We do not quote specific data, as current products are not designed to optimise this and manufacturers are therefore unable to provide it.

Another key performance indicator related to efficiency is voltage degradation. Voltage degradation refers to an increase of the overpotential that has to be applied to an electrolysis cell to maintain constant hydrogen production as the cell ages. The effect is linked to various degradation processes, mainly in the catalyst, electrolyte and membrane, which lead to an increased cell resistance. Values for state of the art systems under continuous operation are in the range of 0.4 to 5 µV per operating hour, though some literature sources suggest values above this range for PEM technology (15 µV/hr). Given that various developers are active in PEM technology this may well be a good estimate of the *average* status of voltage decay, though in best-in-class PEM products it is reported to be below 3 µV per hour.

The voltage degradation effectively results in a reduced average efficiency over the lifetime of an electrolyser system. After 60,000 hours of operation, at a voltage degradation of 5 µV per hour, the

efficiency is roughly 10% lower than at the start of life. Assuming linear degradation over time, the average efficiency penalty would be 5%. However, since available data on long-term degradation are limited, and practically unavailable for dynamic operation, this factor has not been included in the TEA.

Voltage / efficiency degradation is directly relevant to the stack lifetime. Since a stack rarely fails catastrophically, the lifetime is typically defined in terms of this efficiency drop, and the acceptable level of this drop depends on what can be accepted by the operator and when capital investment in a replacement stack may be beneficial. Based mainly on voltage degradation, leading manufacturers of both PEM and alkaline electrolysers currently claim stack lifetimes between 60,000 and 90,000 operating hours. As a best case key performance indicator for 2030, 90,000 hours has been specified for PEM and 100,000 for alkaline technology.

3.2.3 Capital cost

This section provides an overview of the expected cost reductions at electrolyser *system* level (see 3.2.1). Several pathways will need to be pursued in parallel to achieve the hoped-for cost reduction by 2030:

- Higher-volume/mass production
- Supply chain development
- Technology innovation

Technology innovation is discussed in more detail in Section 5, as this is the pathway to cost reduction on which FCHJU activities may have the greatest impact. Volume production and supply chain development will occur in parallel with increased deployment of electrolyser systems, but are broadly not affected by technology development, except for technology innovations that can enable the use of standardised low cost components already in mass manufacture.

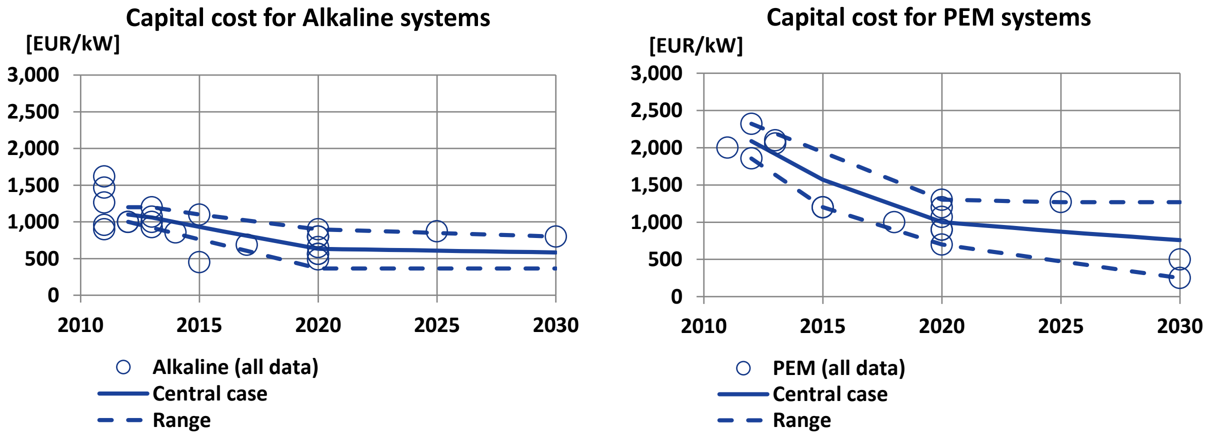
The expected cost reduction data points and trend lines for alkaline and PEM electrolysers are depicted in Figure 4. These are described in € per kW, which can be translated into cost per hydrogen output (€/Nm^3/hr) if multiplied by the energy input (kWh/Nm^3) of a specific system.

Currently available alkaline electrolyser systems cost 1,000 to 1,500 €/kW, plus installation. These costs are expected to reduce to about 600 €/kW by 2020 (central case). More optimistic estimates see alkaline electrolyser costs approaching 370 €/kW (best case). Very aggressive targets of below 200 €/kW have also been stated, although these lie below the typical range of expectations.

The system cost of PEM electrolysers is currently about twice that of alkaline systems. However, it has been reported that in some markets, small PEM systems (<100 kW) are competitive with alkaline. Costs at around 1,000 €/kW (central case) are expected by 2020, although several manufacturers anticipate costs near 700 €/kW (our best case). Limited data on cost reductions beyond 2020 are available, though in the best case PEM cost could drop to 250 €/kW. As the uncertainty is significant, the central case cost comes to 760 €/kW.

To put these significant expected cost reductions into context, it is important to note that today, electrolysers are built in small volumes for niche markets. Electrolyser companies have limited supplier choices and often BoP components designed for other industrial applications have to be bought, which may be both more expensive than they could be and inappropriate for the specific

needs of an electrolyser system. Even for alkaline electrolysis, which is regarded as a fully ‘mature’ technology, sales and hence production volumes are low and technology innovation potential exists. In this case it is expected that much of the cost reduction potential comes from an improved supply chain, and through increased production volumes for which more cost-efficient production techniques can be used. The achievement of the expected reductions in cost is therefore directly dependent on the level of deployment in a given time period. For PEM and other less well-established technologies, technology innovation is seen as a comparatively more important contributor to anticipated cost reductions.



System cost [1]			Today	2015	2020	2025	2030
EUR/kW	Alkaline	Central	**1,100**	**930**	**630**	**610**	**580**
		Range	1,000 - 1,200	760 - 1,100	370 - 900	370 - 850	370 - 800
	PEM	Central	**2,090**	**1,570**	**1,000**	**870**	**760**
		Range	1,860 - 2,320	1,200 - 1,940	700 - 1,300	480 - 1,270	250 - 1,270

[1] incl. power supply, system control, gas drying (purity above 99.4%). Excl. grid connection, external compression, external purification and hydrogen storage

Figure 4: Cost reduction trend lines for alkaline and PEM electrolysers

Very few actors are developing AEM electrolysers, and commercial products are only available from one manufacturer. While data on technical parameters for AEM was collected, data on cost and cost reduction potentials could not be gathered for AEM electrolyser systems. For SOE, literature suggests that systems *might* become available between 2015 and 2020 at a cost of roughly 2,000 €/kW, while the cost would approach 1,000 €/kW between 2020 and 2030 and might reach 300 €/kW in the longer term. This has broadly been confirmed in interviews with stakeholders, though nobody can state with any confidence when systems might *actually* become available.

3.2.4 System and stack size

Today’s PEM technology is available only at smaller scale than alkaline technology. While MW-scale PEM *systems* are available, these still consist of multiple individual stacks, whereas alkaline *stacks* of several MW are commercially available. However, several PEM manufacturers are working on MW scale stacks and commercial MW-scale products are expected no later than 2015. Scale may therefore not remain as a differentiator between PEM and alkaline technology.

System scale is often related to system cost. However, in electrolysis this ‘scale effect’ on cost is less pronounced than in other technologies (such as thermal power plants), as the size of a system scales almost linearly with the cell area. Larger systems can however bring cost advantages with regard to balance of plant (e.g., inverter, gas drying, system control). Literature suggests that these cost reductions can be significant when going from kW systems up to 500 kW (Smolinka, 2011), but flatten after this point.

It is worth noting that the best case cost data gathered refer both to systems below 5 MW and above 10 MW. While there is broad agreement that the cost reductions expected by 2020 will require system sizes of at least 1 MW, different views exist on how significant scale effects will be beyond 1 MW.

Developing large cell (and therefore stack) areas is expected to increase the active cell area that can be utilised and proportionally reduce the amount of expensive materials used. In other words large cell designs have less ‘waste’ material in plate edges and manifolds compared to multiple smaller cells. Until other technical constraints (such as uniformity of current density) are reached, using larger single cell areas may result in ~30-50% less material than small ones at equivalent current densities.

In contrast, the concept of multiple smaller stacks (i.e., smaller cell areas) mainly relies on cost reductions deriving from volume manufacturing and supply chain development. These cost reductions are expected for large cell design as well. However, advocates of the small cell design point out that at a given capacity deployment, large stack concepts reach high volume production of their individual cell components later than small stack manufacturers.

3.2.5 Operational cost (excluding electricity)

We define operational cost (opex) to include costs such as planned and unplanned maintenance, as well as overhaul, but not the electricity cost. Often these costs are provided as a percentage of initial capital expenditure (% of capex per year). Only a few manufacturers were able to provide us more specific indicative figures. All available data points suggest opex values of 2-5% of capex per year, with no distinction between different technologies. It is important to note that this figure does not include end-of-life stack replacements.

In practice costs vary widely depending on plant size as the required labour to maintain one system does not scale linearly with system size. In addition labour costs vary by plant location. However, based on feedback from manufacturers, operational costs have been broken down into material and labour related costs. Material costs typically scale with size and are linked to the initial system cost. Labour is dependent on system scale, i.e., how many full time equivalents (FTE) are required per plant.

For the techno-economic analysis, annual materials opex of 1.5% of the initial capex is used, while labour-related costs for operation and maintenance have been estimated per use case dependent on plant size. This results in lower per-MW costs for very large plants – for example a 1 MW electrolyser system might have annual operational cost (excl. of electricity) of 5% of initial capex, while this figure would reduce to 2% for a 10 MW plant. In addition to this, stack replacement costs have been included in the operational costs in the techno-economic model.

3.2.6 Pressurised operation

Pressurised operation can reduce or eliminate the cost of an external compressor and its associated additional piping, safety and control equipment. Pressurised electrolysis is therefore often stated as an important factor to improve cost competitiveness in use cases that require pressurised hydrogen, such as transport refuelling station and gas grid connected electrolysers.

In a pilot project in Hamburg, where electrolytic hydrogen will be directly fed into a 55 bar natural gas network, significant overall project cost savings are expected through the use of a 60 bar pressurised electrolyser (Schoof, 2013). The reduced system cost and operational advantages (reduction or elimination of maintenance for external mechanical compression) have led to a demand for pressurised electrolysers. Today pressurised electrolysers, typically delivering hydrogen at 30 bars, are established on the market. Products delivering higher pressures are less mature, and can be considered as early commercial.

Stakeholders active in pressurised electrolysis concur that most commercial products will provide hydrogen at 30 bars through 2030, with higher outlet pressures offered in specific products. Naturally, views on the importance of pressurised electrolysis vary depending on manufacturers' philosophies. Suppliers of atmospheric electrolysers also offer full system solutions including external compression and often question the value of internal (electrochemical) compression in the electrolyser.

3.2.7 Dynamic and flexible operation

Historically, electrolyser systems have been designed to operate continuously at a set operating point to deliver a hydrogen stream of defined purity and pressure for industrial applications. However, a number of the use cases and operational strategies discussed here as potentially relevant to the future deployment of electrolysers (such as energy storage applications, or providing reserve services by load shedding) require the electrolysers to be operated dynamically.

The manufacturers consulted indicated considerable uncertainty around both what these applications might be and what technical performance characteristics would be needed to meet their requirements. Some manufacturers proposed that it would be extremely helpful if standard operational and test cycles were defined for representative applications. This would not only provide some clarity on the required performance characteristics but would also allow different electrolysers to be compared more readily.

Nevertheless, several manufacturers have solutions at hand for dynamic system design and have realised ramp rates of up to 100% of nominal load per second in their labs. However, effects of fast ramping regimes on stack and system lifetime are not yet well quantified.

4 Findings from the techno-economic analysis

The full techno-economic analysis is included as Appendix 5. The methodology, results and implications are summarised here.

4.1 Methodology

The techno-economic model shown in Figure 5 was developed to evaluate the cost of hydrogen from water electrolysis systems, based on the key performance indicators outlined in Section 3.2. For grid-connected systems, historical electricity spot price data[10] is combined with projections for average electricity prices for EU industrial users (Directorate General for Energy, 2011), to provide a time series of forecast future spot prices. Country-specific electricity network charges and taxes are added to provide an estimate of the cost of electricity at the point of consumption by the electrolyser. The forecast carbon intensity of grid electricity in each country (Directorate General for Energy, 2009) provides a way to assess the embedded CO_2 in each unit of hydrogen produced using water electrolysis.

Off-grid renewable generators providing a low-carbon, intermittent electricity supply have also been considered, including the relevant expected change in subsidy support, where that information is available.

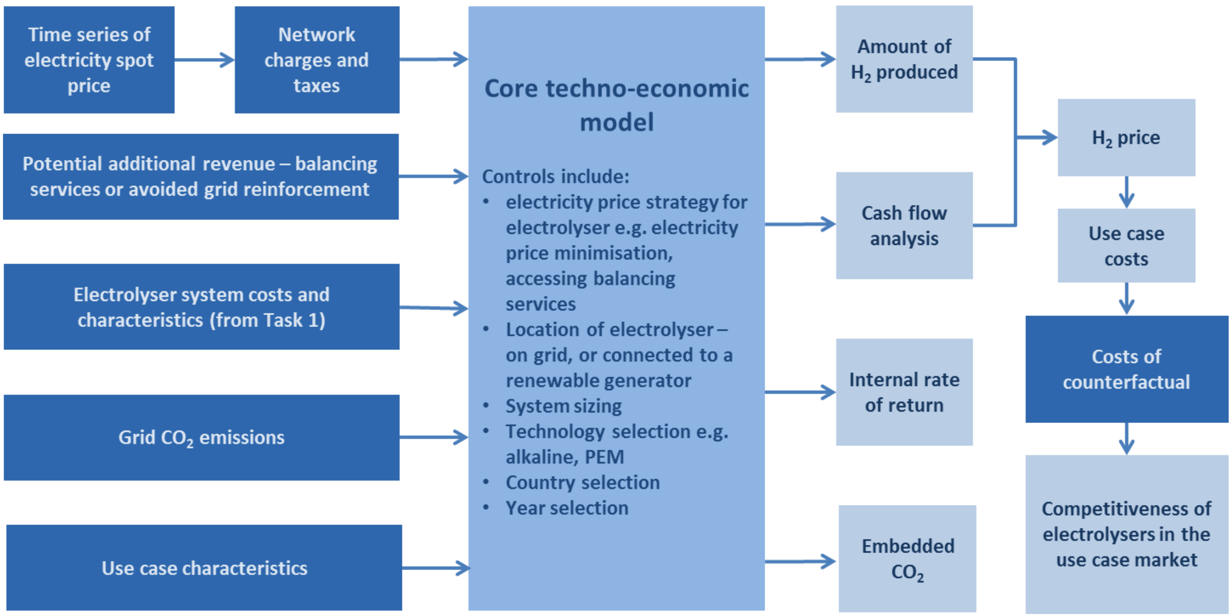


Figure 5: Techno-economic model components

Operating strategies to provide additional revenue for the water electrolyser operator were also modelled, including providing load balancing services for the electricity grid[11], or siting the system in a location that allows grid operators to avoid reinforcing the network.

[10] (APX Power Spot Exchange, 2012), (European Energy Exchange, 2012), (OMIE/OMEL, 2012), (Polish Power Exchange, 2012), (Nordpool Spot, 2012)

[11] Unless explicitly stated, we model electrolyser systems operating at 100% load when not called upon to provide load balancing services. Analysis of the merits of part-load operation strategies is in Section 4.7.

The costs incurred over the lifetime of the water electrolyser, and the income received from providing grid services in each operating strategy and country, are combined with the amount of hydrogen produced in that scenario, resulting in a production cost of the hydrogen from water electrolysis.

By accounting for additional downstream costs in delivering the hydrogen to different key use cases, the end-cost to consumers is quantified and its competitiveness to counterfactual methods of hydrogen provision evaluated.

4.2 Cost of electrolytic hydrogen at mainstream grid prices

To provide representative data sets for different types of regulatory and pricing environment, values from five European member states were selected for detailed analysis. The different countries were selected to represent significant variations (by electricity price, penetration of renewables and overall market size). The cost of hydrogen from water electrolysis is expected to vary significantly between countries in both 2012 and 2030, shown in Figure 6 and Figure 7, due to a large range in electricity prices for industrial consumers (e.g. Figure 8). In Figure 6 and Figure 7, hydrogen production costs with the provision of 'Balancing Services' are only provided for the UK and Germany – as these are the only countries that publish load balancing data. Also, 'RG only'[12] refers to an off-grid scenario, connected by private wire to a 31% capacity factor wind farm. Finally, for these Figures, electricity price volatility has been assumed to be the same as in 2012.

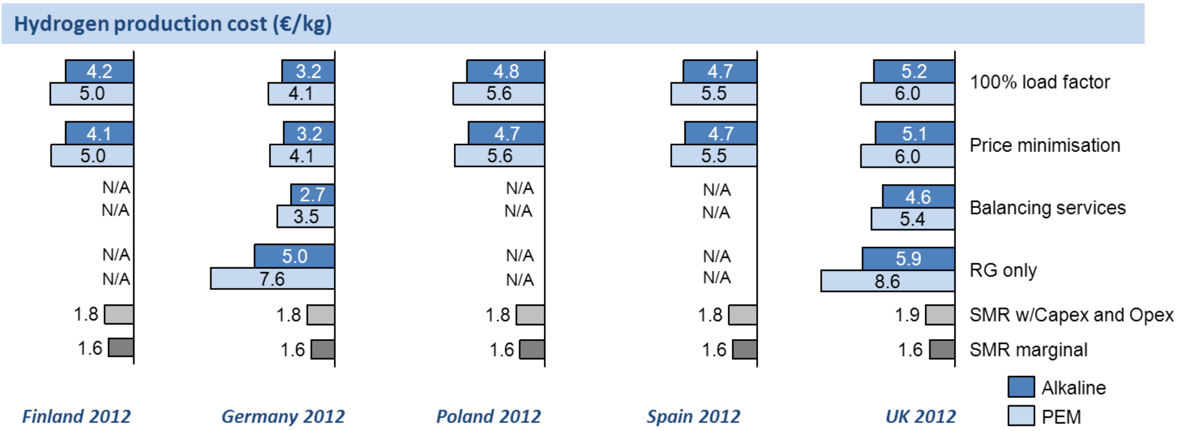


Figure 6: Hydrogen production costs in 2012 for best case KPIs for Alkaline and PEM electrolysers in different electricity market scenarios

[12] RG for Renewable generator

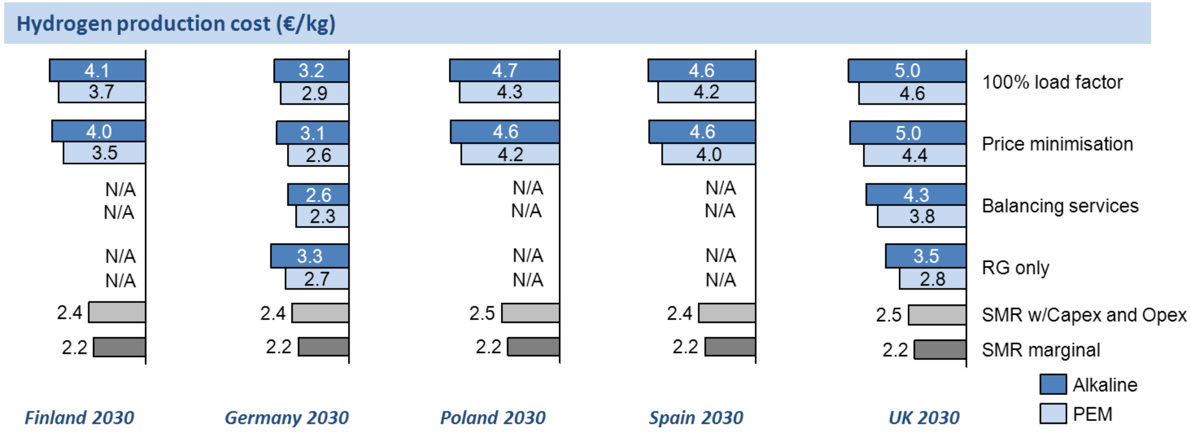


Figure 7: Hydrogen production costs in 2030 for best case KPIs for Alkaline and PEM electrolysers in different electricity market scenarios.

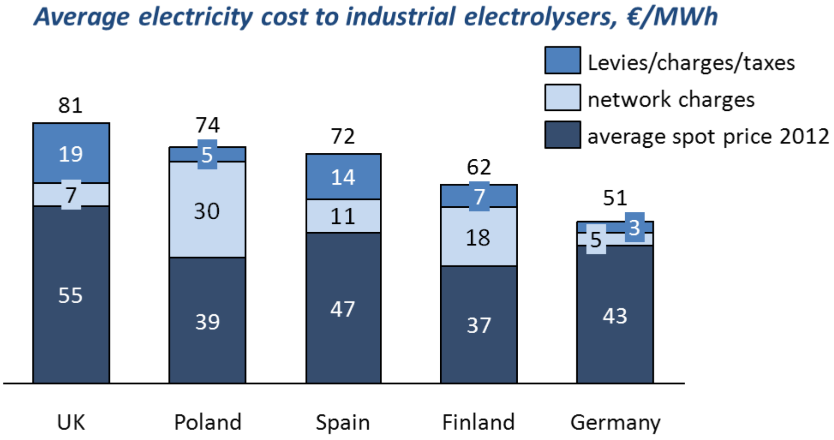


Figure 8: Average electricity cost to industrial electrolysers in 2012

4.3 Strategies to reduce the cost of electrolytic hydrogen

Operators may elect to develop more sophisticated strategies to reduce costs or maximise revenues. For on-grid water electrolysers, Germany exhibits the lowest H_2 production costs in 2012 thanks to (a) low wholesale electricity prices and (b) reductions in the transmission/distribution costs payable by industrial electrolyser users. As a consequence, the best operating strategy for water electrolysers is to source grid electricity and provide grid balancing services, where electrolysers modify their electrical demand according to a signal from the network operator - a service for which they receive a payment.

The volatility of electricity spot prices is both important in optimising operation strategies and in understanding potential revenues. A more volatile scenario, corresponding to significant amounts of grid-connected renewable generation, is considered later.

The situation reverses in the UK, where high electricity prices and transmission/distribution fees implies that on-grid electrolysers struggle to compete, even with balancing payments. Here, the most cost-effective strategy is to be powered by generators which cannot otherwise connect to the grid. The best proxy for this is stranded wind generators, which would connect but are prohibited due to capacity constraints. The much lower cost of hydrogen from renewable generation in 2030,

compared to the 2012 levels, is a result of both Capex/Opex reduction and efficiency improvements in electrolysers.[13]

Given that these cases act span the space of electricity prices, we focus on analysing Germany and the UK to quantify the impact of the observed market conditions and regulatory environment on hydrogen costs.

4.4 Use cases and cost of electrolytic hydrogen at point of use

The production cost of hydrogen from water electrolysers only tells part of the story. To fully assess electrolytic hydrogen potential, we have defined use cases which determine the steps required to take the hydrogen from the electrolyser system and deliver it to the end user. This allows the associated costs to be calculated. Three broad categories are explored, varying both the size of the electrolyser systems, and the end use for the hydrogen, and each is subsequently compared with a relevant counterfactual:

Use cases:

- **Small systems for transport applications.** This use case explores the steps and associated costs required to use electrolytic hydrogen in hydrogen refuelling stations (HRS) for fuel cell vehicles and buses. A range of system sizes is explored, serving car HRS or bus depots. The relative merit of on-site electrolysis is compared to delivery from a large centralised electrolyser.
  - Counterfactual: centralised SMR plant, incurring distribution costs.
- **Medium systems for industrial applications.** This use case explores the steps and associated costs required for electrolytic hydrogen in industrial applications, such as ammonia production. A range of system sizes is explored, and it is assumed that an electrolyser produces hydrogen for an industrial park, and the hydrogen is transported to individual sites by pipeline.
  - Counterfactual: centralised SMR plant in industrial park, delivering hydrogen via pipeline network.
- **Large systems for energy storage applications.** This use case explores the steps and associated costs required to use electrolytic hydrogen as an energy storage medium, by considering large scale systems which could take advantage of excess renewables or other cheap electricity. The end uses considered are re-electrification, use as heating by injection into the gas grid, and use as a transport fuel.
  - Counterfactuals:
    - forecast grid electricity wholesale prices;
    - natural gas in the gas grid; and
    - hydrogen for transport supplied from a centralised SMR plant, including distribution costs.

The use cases are summarised in Figure 9, and detailed assumptions for each end use can be found in Appendix 5.

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[13] Note that the renewable subsidy level in the UK is assumed constant at the 2012 level, whilst it is tapered in Germany (reduction: 1.5% p.a.).

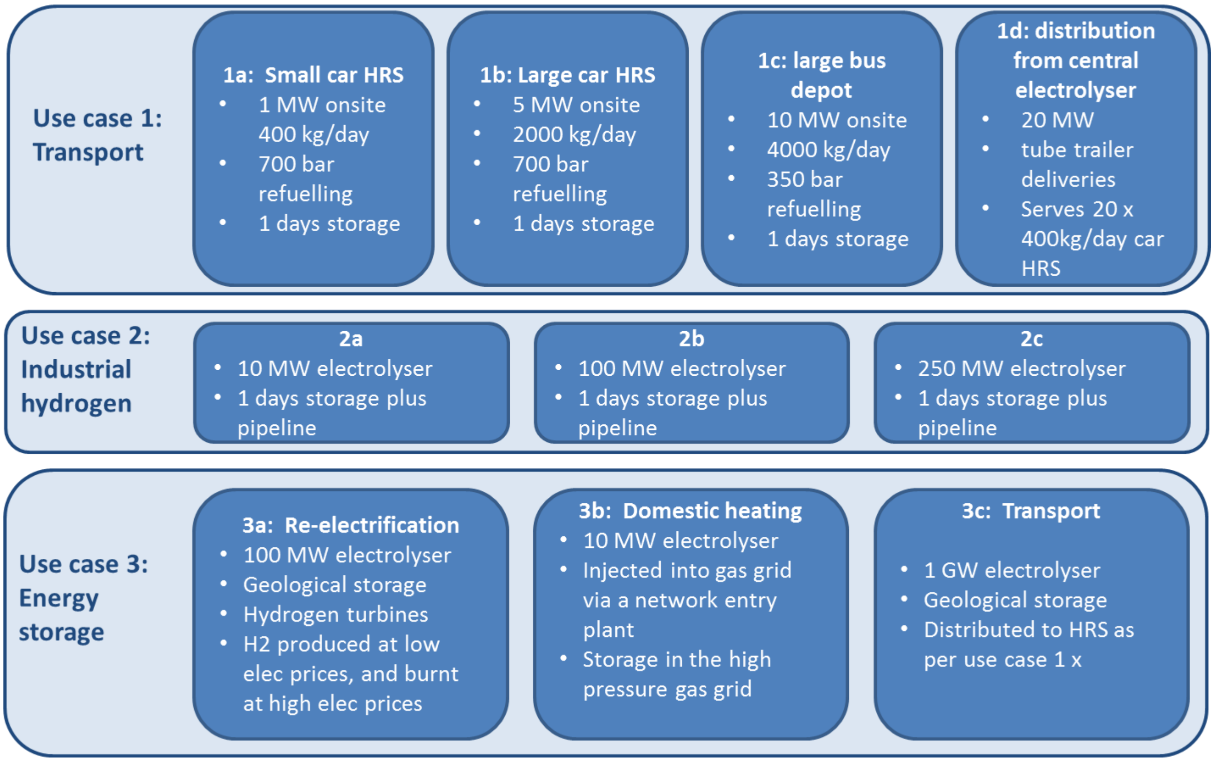


Figure 9: Summary of applications and use cases

4.4.1 Grid-connected water electrolysers in Germany, 2030

Figure 10 to Figure 12 below show the results for each use case in Germany, indicating that for *distributed* transport applications (where the electrolyser is sited at the station), achieving the *central* KPIs will allow water electrolysers to compete with the SMR counterfactual, provided the electrolysers can attract grid balancing payments. This is because the cost of hydrogen distribution for the centrally produced SMR is higher than any additional cost of electrolytic production. For a mode where hydrogen is distributed from centralised electrolysers to filling stations, competition only appears feasible if the *best case* KPIs are met. In these figures the electrolysers are operated in grid-connected mode and provide balancing services.

In industrial and energy storage applications, however, even water electrolysers achieving best case KPIs will find it challenging to compete in the majority of use cases, without additional carbon payment (or very high balancing revenues).

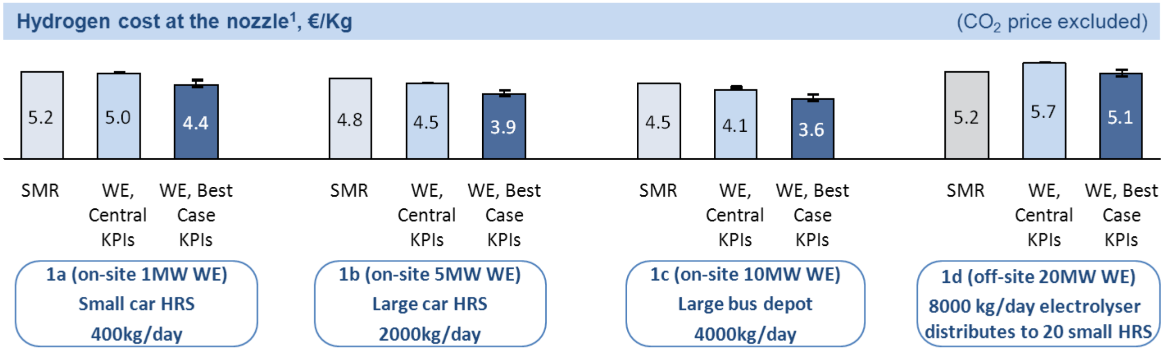


Figure 10: Hydrogen cost at the nozzle for transport applications in Germany, 2030.

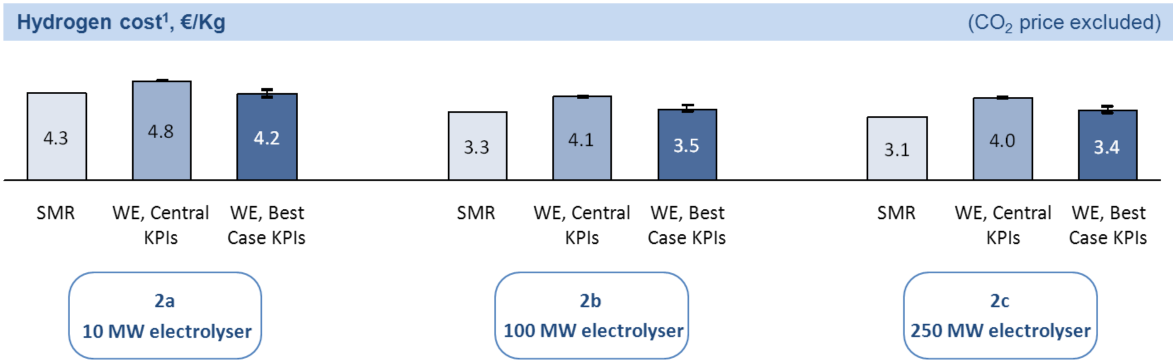


Figure 11: Hydrogen cost at the point of use for industrial applications in Germany, 2030.

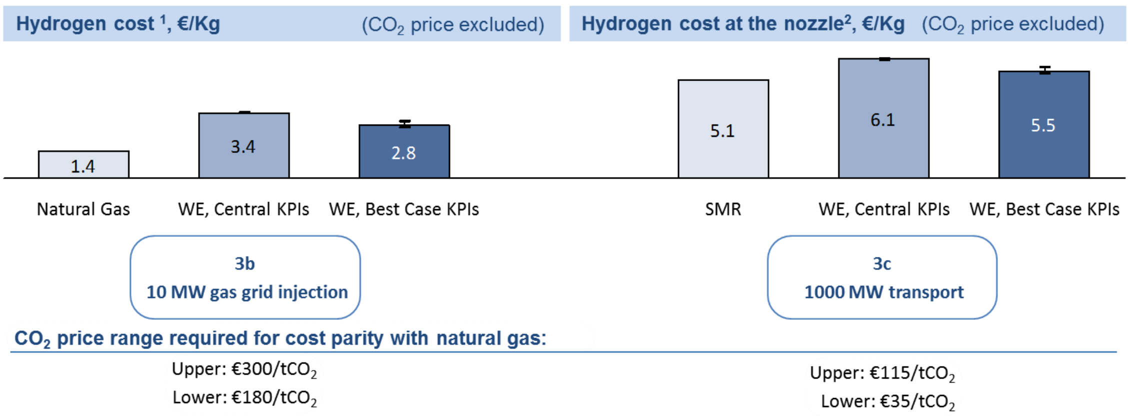


Figure 12: Hydrogen cost at the point of use for energy storage applications in Germany, 2030.

4.4.2 Off-grid water electrolysers in the UK, 2030

In the UK, the cost of hydrogen from electrolysis is higher than SMR in 2030, even for the stranded renewable mode of production. As a result, only with *best case* KPIs and the transport end-use can competition with SMR-derived hydrogen be envisaged (Figure 13). For non-transport uses, additional carbon pricing or other changes in the regulatory regime appear necessary to enable

competitiveness (Figure 14 and Figure 15). For this analysis, the electrolysers are operated off-grid, connected to an equivalent-sized wind generator with a 31% capacity factor.

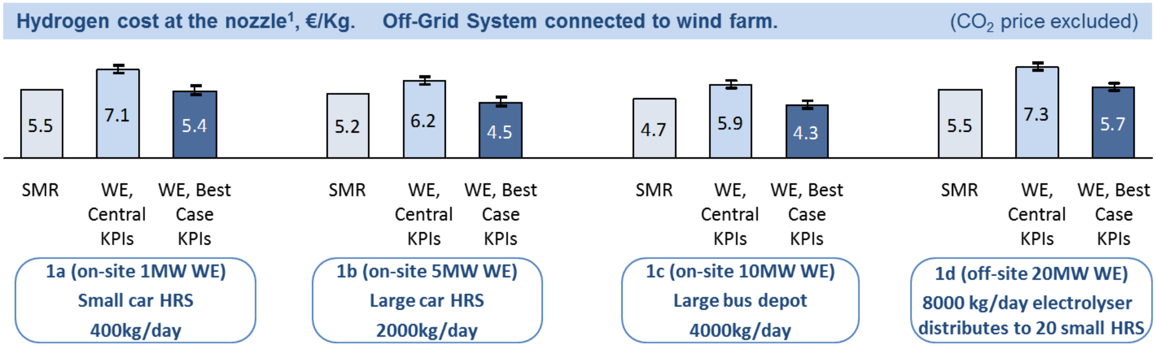


Figure 13: Hydrogen cost at the nozzle for transport applications in the UK, 2030.

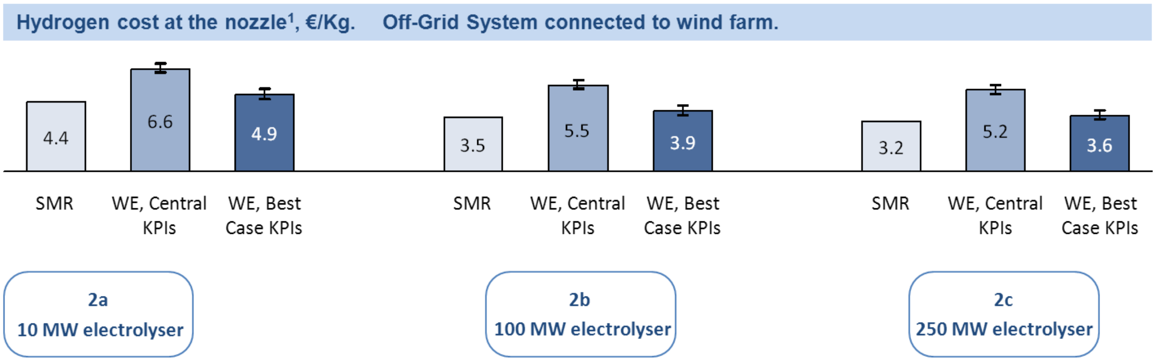


Figure 14: Hydrogen cost at the point of use for industrial applications in the UK, 2030.

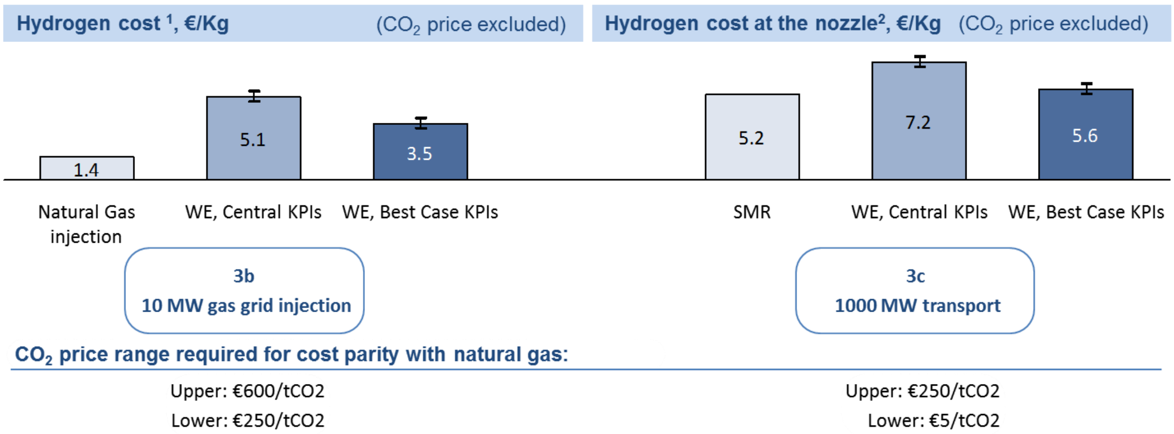


Figure 15: Hydrogen cost at the point of use for energy storage applications in Germany, 2030.

4.5 Assessment of technical targets by use cases

For each use case, it is important to determine the KPI targets for that will allow water electrolysers to compete with the respective counterfactual. In the graphs below, these KPI values are shown. Because of the number of parameters, we display two values for each main WE technology (PEM and Alkaline) to reflect the upper or lower bound values for all of the KPIs not shown in the graph (Figure 16–Figure 21). Note that for all these figures, a single KPI has been varied while all other KPIs have been maintained at *central* or *best case* values as indicated in the legend.

Figure 16 to Figure 21 show, importantly, that distributed transport applications could compete in both the UK and Germany within the range of target KPIs identified as plausible.

For industrial hydrogen and very large electrolyser applications, a combination of capex reductions and electricity/balancing services prices beyond current mainstream expectations is likely required to enable electrolytic hydrogen to compete.

The sensitivity analysis also considers the level of carbon price required to enable competition with the counterfactual. This is a proxy for the level of policy support which would be required in order to make the use case competitive. The graphs illustrate that at DG ENER's projected 2030 carbon price (44 €/tonne) and best case KPIs, electrolysers could be competitive in each of the transport and industrial use cases considered here. This suggests that with supportive (but plausible) policies, the application of electrolysers could be broadened beyond the transport sector to also include industrial chemicals.

4.5.1 Technical Targets for Germany, 2030

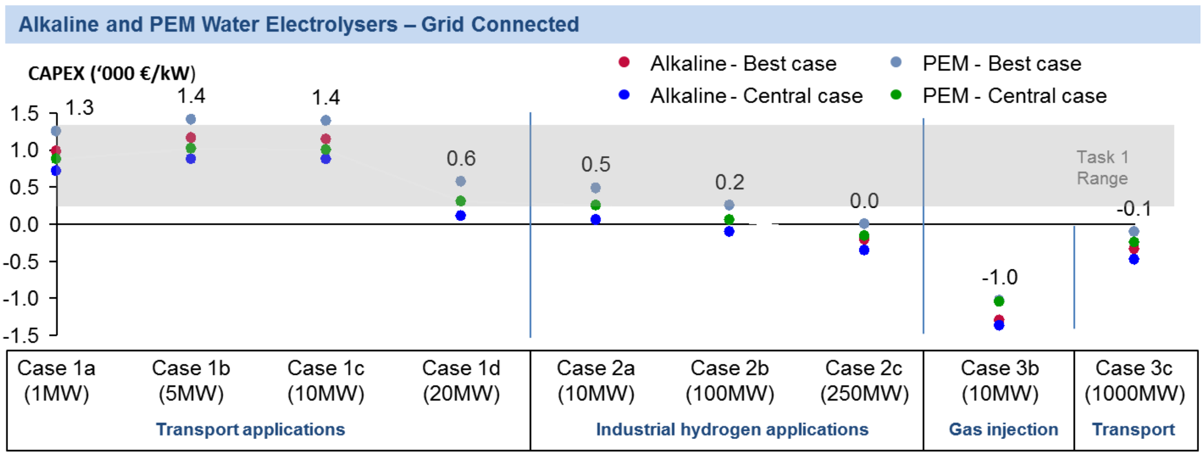


Figure 16: Capex targets for Alkaline and PEM technologies required to compete with counterfactual in Germany, 2030.

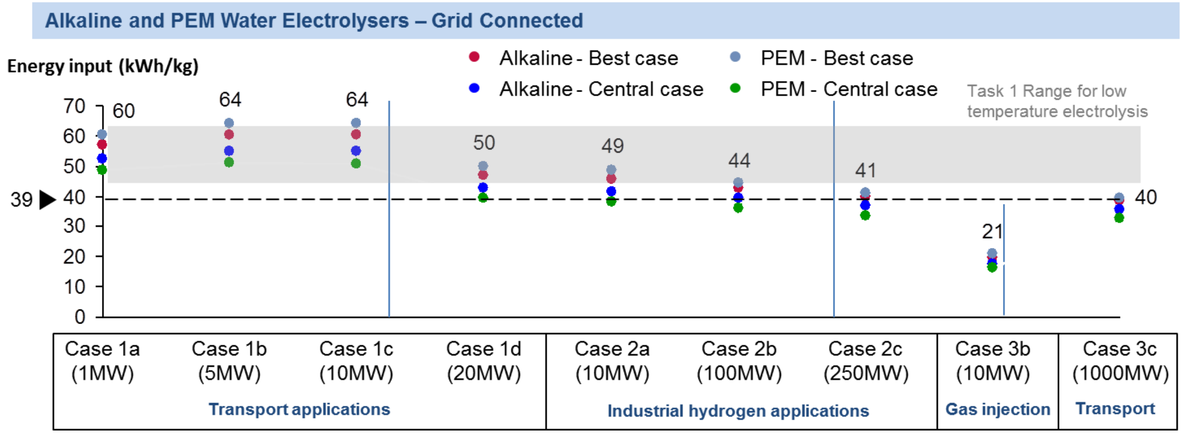


Figure 17: Energy input targets for Alkaline and PEM technologies required to compete with counterfactual in Germany, 2030.

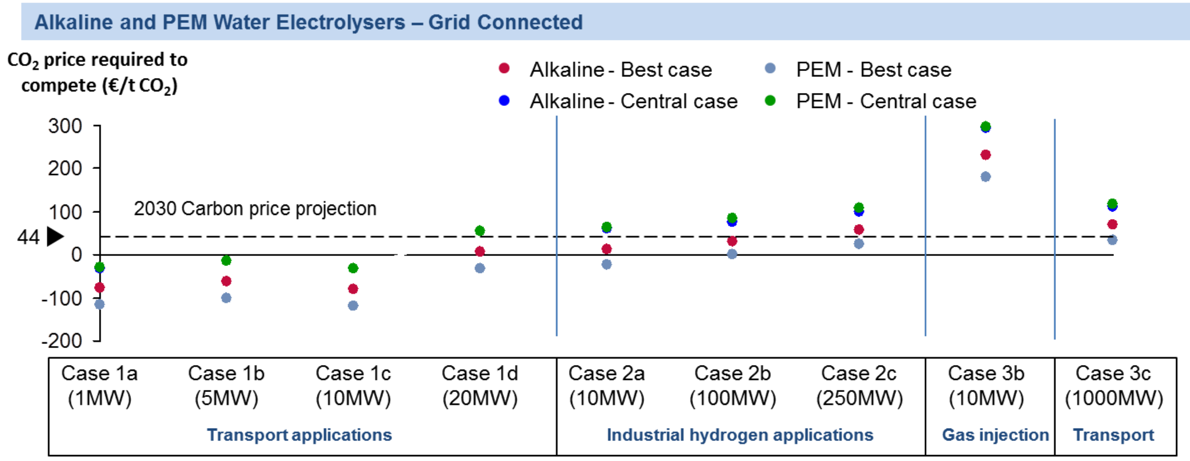


Figure 18: CO_2 price targets for Alkaline and PEM technologies required to compete with counterfactual in Germany, 2030.

4.5.2 Technical Targets for the UK, 2030

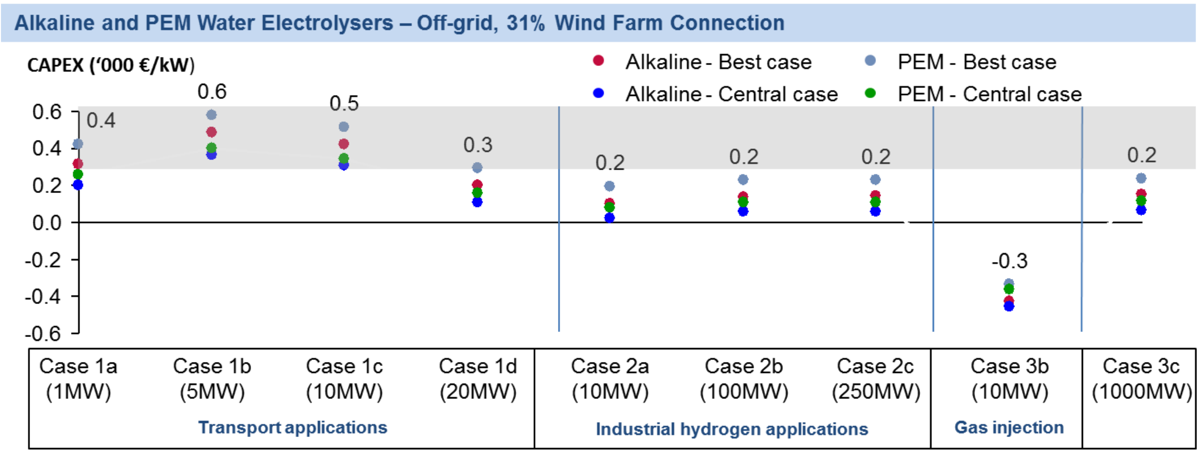


Figure 19: Capex targets for Alkaline and PEM technologies required to compete with counterfactual in the UK, 2030.

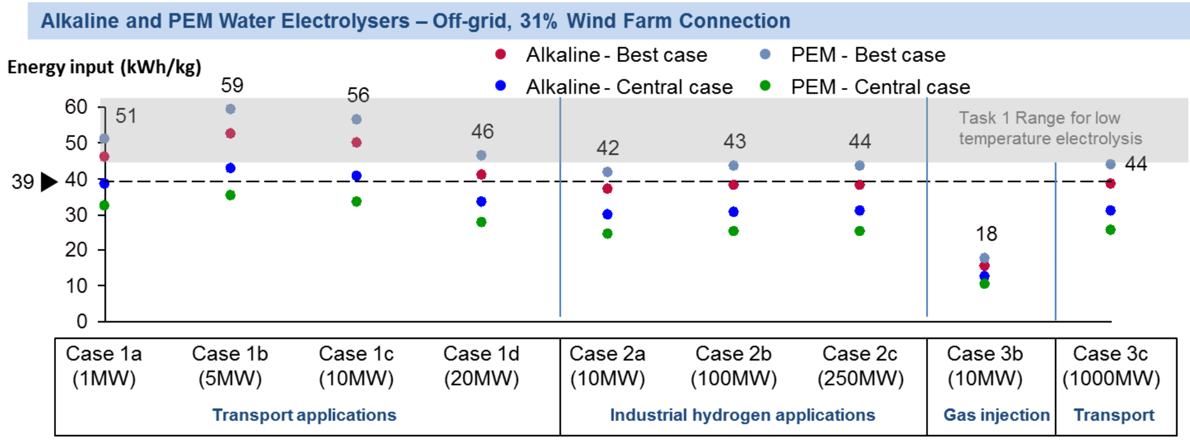


Figure 20: Energy input targets for Alkaline and PEM technologies required to compete with counterfactual in the UK, 2030.

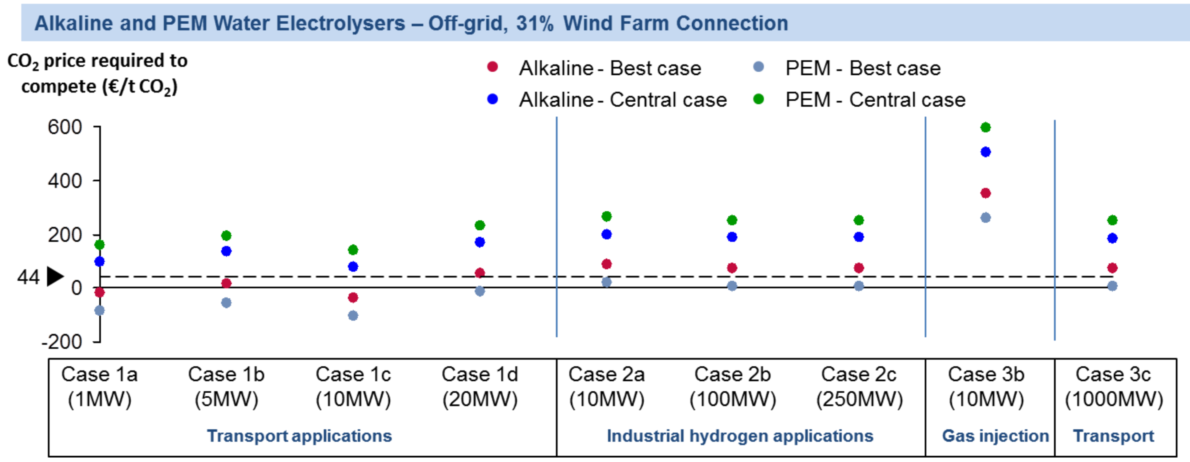


Figure 21: CO_2 price targets for Alkaline and PEM technologies required to compete with counterfactual in the UK, 2030.

4.6 Impact of increased electricity price volatility

Electricity price volatility could also influence the viability of electrolysers in energy applications. Here two scenarios are used: one extrapolated for 2030 based on today's volatility, and one published forecast of future scenarios (Redpoint Energy, 2009). The graphs below illustrate the two price profiles.

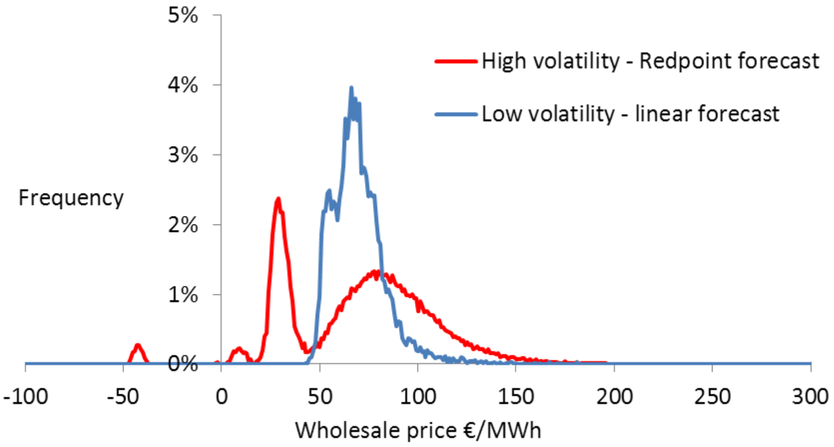


Figure 22: Two scenarios for the volatility of UK electricity prices in 2030.

The 'linear forecast' uses the 2012 electricity spot price frequency distribution, modified to be consistent with the DG ENER price for 2030. The 'Redpoint forecast' uses the "environmentally favourable conditions" frequency distribution curve (i.e. a high renewables penetration scenario) for 2030, modified so that the mean is consistent with the DG ENER forecast for 2030.

4.6.1 Re-electrification in volatile price situations

The model selects an optimum balance of generating electricity at times of low electricity price and re-exports at the highest price (via a gas turbine). In markets with today's electricity price volatility, re-electrification using hydrogen as an intermediate storage medium is not financially viable, as the spread between high and low electricity prices cannot compensate for the efficiency losses in the system. Further details of the generation costs associated with re-electrification in markets with today's electricity price volatility can be found in Appendix 5. Even using the high electricity volatility scenario, re-electrification using hydrogen as a storage medium does not appear competitive.

Notably, even in this ideal and optimised scenario, the cost of electricity from re-electrification is ~40 €/MWh greater than the average spot price received for the exported electricity. The value of energy storage in the electricity network by 2030 is highly uncertain, and there is potential for competitive re-electrification use cases via hydrogen in highly volatile electricity markets, should these services start to attract some form of tariff for the provision of storage services. However, according to this analysis, stored electricity would need a value of at least ~40 €/MWh (above the underlying pricing signal) to be viable.

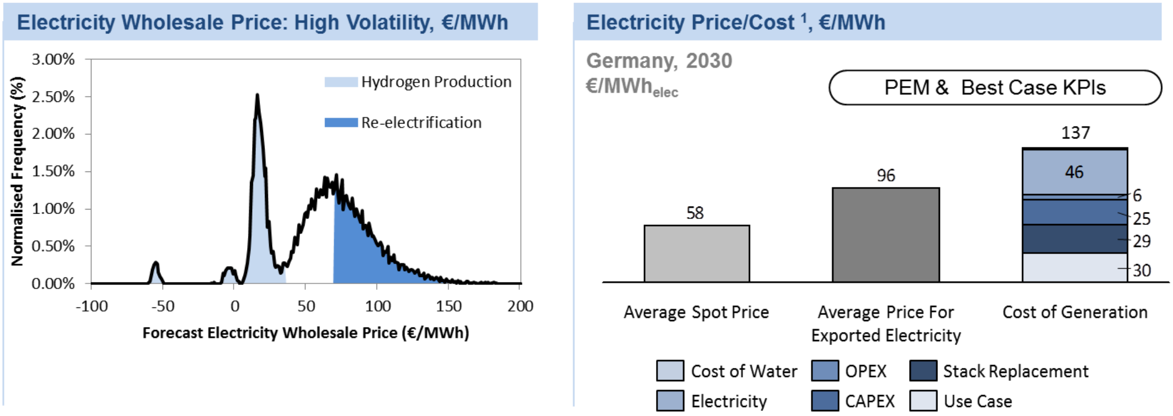


Figure 23: Re-electrification (use case 3a) and the cost of generation and price received for exported electricity in a high volatility electricity market, 2030

4.6.2 Effectiveness of price minimisation strategies in volatile price situations

Price arbitrage strategies could offer promising returns for electrolyser operators in a world with more volatile grid electricity prices. For example, in Germany, in cases where best-case KPIs are achieved, the benefits of avoiding high electricity prices outweigh the capex burden associated with operating at low load factors. For example, this allows an end-use cost of 3.7 €/kg H_2 to be achieved in the small car HRS use cases, which is lower than the conventional volatility case by 0.5 €/kg.

The success of price minimisation strategies depends on developing low capital cost electrolysers (to allow them to operate at low load factors without imposing too high a capital burden) which have rapid demand response.

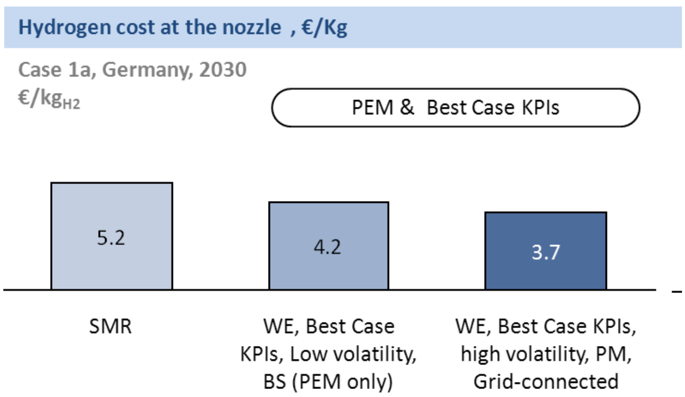


Figure 24: End-use cost of hydrogen in a world with volatile electricity prices

4.7 Impact of smart balancing strategies

Data from manufacturers shows that, within certain boundaries, electrolysers can achieve higher efficiency when operating at part-load. By operating normally at part-load In some balancing markets (notably Germany), the electrolyser is able to offer both positive (reduction in electrolyser load) and negative (increase in electrolyser load) balancing services, effectively doubling the revenue from balancing services for each unit of hydrogen produced. The analysis suggests that once electrolyser

capex falls to central or best case KPIs, the benefits from additional efficiency and balancing payments could outweigh the additional financial burdens of operating at part load (increased capex and opex costs per unit of hydrogen).

The impact of such a strategy has been modelled for Germany in 2030, assessing the production cost of hydrogen from water electrolysis adopting both a full-load (100%) and part-load (50%) approach (Figure 25). The electrolyser is sized to provide the same amount of hydrogen in both cases.

A cost reduction of up to 1.40 €/kg can be achieved for hydrogen at the point of production, if several concurrent factors are achieved:

- a regulatory regime that allows both positive and negative balancing to be sold from the same unit;
- achieving suitable efficiency at part load;
- capturing the revenue from load balancing for all the balancing offered (this may be limited for the largest water electrolysers, as contracts of over 50 MW are unusual in the balancing market); and
- achieving the best case KPIs, of which low capex and low energy input are key.

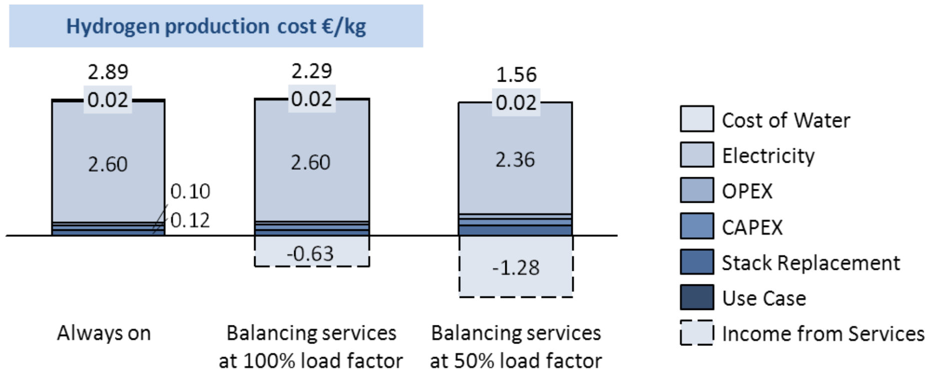


Figure 25: Production cost of hydrogen in Germany, 2030, under full-load and part load operating strategies, offering balancing services.

4.8 Impact of output pressure from electrolysers

The output pressure of water electrolysers is most relevant for applications where subsequent compression to significantly higher pressures is required (e.g. transport). Electrolysers currently being developed could produce hydrogen at a higher pressure than today's commercial products, through internal electrochemical compression. This requires a higher specific electricity input (a higher voltage is needed) than unpressurised operation, but overall is generally more energy efficient than external mechanical compression, and potentially more reliable. However, some manufacturers with cell designs optimised for pressurised operation (~30 bar) do not encounter any efficiency advantage when operating these systems unpressurised.

The key difference between internal and external compression lies in the amount of electricity used in the internal compression process, and any capital and operation costs relating to additional compression demands. We have simulated electrolyser output at 1 bar, 30 bar and 100 bar, with best

case KPIs for all parameters[14]. For a large centralised water electrolyser producing hydrogen for transport use, modest reductions in the overall cost of delivered hydrogen (~0.10 €/kg$_{H2}$) are noted when using a 100 bar electrolyser instead of an electrolyser operating at atmospheric pressure (~1 bar) – through bypassing intermediate compression steps and thus reducing both capex and opex of the external compressor. However, in our example, using a 100 bar electrolyser instead of a 30 bar electrolyser does not enable an additional compression step to be avoided and so only a minor cost reduction per kg$_{H2}$ is achieved, mainly due to lower electricity use from better compression efficiency.

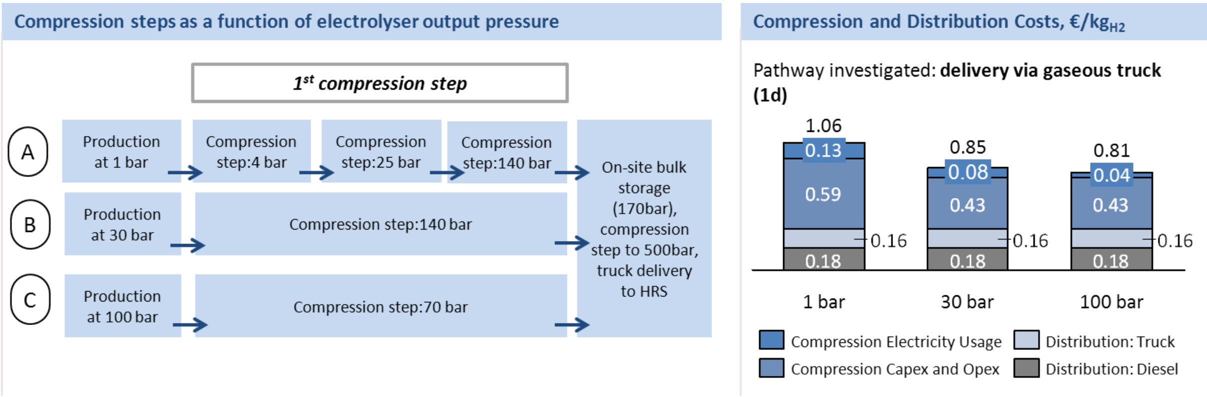


Figure 26: Compression steps at different electrolyser output pressures, with compression and associated costs derived from the DOE H2A model

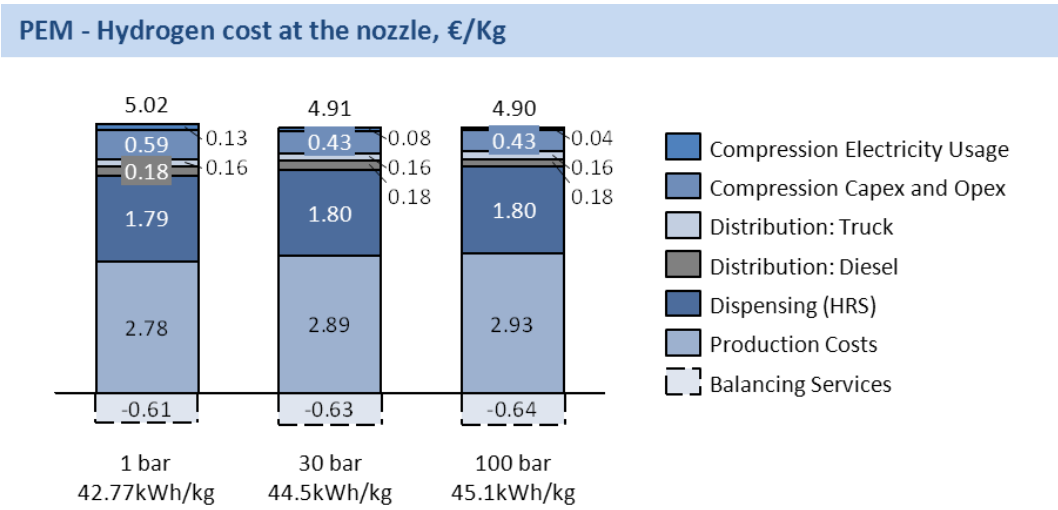


Figure 27: Hydrogen cost at the nozzle, dependent on pressure of electrolyser (Case 1d, large centralised water electrolyser producing hydrogen for transport use)

4.9 Conclusions

At the point of production, hydrogen from electrolysis will in most cases remain more expensive than hydrogen from large SMR plants, even accounting for expected electrolyser technology and cost

[14] Electrolyser efficiency has been adjusted to take internal compression into account

improvements between now and 2030 (electrolysis: 2.3–5.0 €/kg_{H2} in 2030, SMR 2.2–2.5 €/kg_{H2} in 2030). This is primarily due to the high cost of electricity relative to natural gas, as electricity accounts for 70–90% of the cost of a kilogram of hydrogen produced through electrolysis. The most competitive markets for hydrogen from water electrolysis will be characterised by low effective electricity prices available to electrolyser operators, through a combination of low wholesale electricity costs and low network charges and taxes.

In addition to meeting the best case key performance indicator trends, the analysis suggests that electrolytic hydrogen can compete commercially with SMR hydrogen in certain circumstances by drawing value from other sources. Where they provide *distributed* hydrogen production, electrolysers can avoid high logistical distribution costs incurred in delivery of *centralised* SMR hydrogen. In addition, where regulations allow, electrolysers can provide paid-for grid services by operating as a controllable load, with the revenue thus lowering the effective cost of the hydrogen they produce. Of the countries considered in the study, Germany and the United Kingdom allow electrical *loads* to provide balancing services, and Finland allows it in a limited manner, whereas Poland does not, and the situation in Spain is under revision.

A favourable regulatory and policy context can also enable hydrogen from electrolysers to be commercially viable. In Germany, electrolyser operators currently avoid a 20.50 €/MWh electricity tax, while industrial clients are often exempt from the 52.70 €/MWh renewables surcharge, and pay as little as 20% of typical grid fees. In the UK, an off-grid electrolyser coupled to a wind farm can avoid all grid fees and network charges and still qualify for Renewables Obligations Certificates (ROCs), worth about 51 €/MWh in 2012. These very different regulatory and policy regimes each have the effect of significantly reducing the overall cost of electricity to an electrolyser operator fulfilling the conditions, and thus help electrolysers to reach commercial competitiveness with other sources of hydrogen.

4.9.1 Vehicle refuelling applications

At low industrial electricity rates, such as in Germany, the analysis suggests that distributed, on-site electrolysers can reach commercial competitiveness with SMR by 2030 for vehicle refuelling applications, provided that the KPIs denoted by the *central* trend are met (use cases 1a–c, spanning sizes between 1 and 10 MW[15] in this study). In the UK, off-grid, distributed electrolysers (use cases 1a–c) would reach competitiveness with SMR by 2030 for vehicle refuelling applications, but only provided the *best case* KPI trend is met.

In addition to needing the *best case* KPI trends to be met, larger, centralised electrolyser systems for vehicle refuelling are only likely to be competitive with some level of policy support, such as perhaps a carbon price in the range of 5–250 €/tCO_2[16] (use cases 1d, 3c, spanning sizes between 20 MW and 1 GW in this study). In this application, centralised electrolyser systems face a greater commercial challenge than distributed systems, as the centralised systems, do not benefit from the otherwise avoided distribution costs (like an SMR).

[15] The maximum size of distributed electrolysers was limited to 10 MW in this study, based on stakeholder input.

[16] This required carbon price assumes that the electrolyser operates on renewable electricity and thus produces hydrogen with minimal carbon emissions. This assumption applies to all the carbon prices listed in this section.

4.9.2 Other centralised hydrogen production applications

If the *best-case* KPI trend is met, industrial applications (use cases 2a–c, 10 to 250 MW in the current study) could be marginally competitive with SMR at low industrial electricity rates, such as those in Germany, by 2030. They would probably require some level of policy support to be fully competitive. The value such applications could draw from providing balancing services is uncertain, as the markets for such services operate differently in different countries. The current analysis assumes that the *maximum* load that can be used for balancing services is 60 MW, representative of how this market currently works in the UK. However, other markets specify *minimum* load sizes and may also allow larger loads to participate. Depending on the details of these local markets, larger or smaller systems may be better suited to exploit balancing services.

Similarly, the modelling suggests that simple displacement of natural gas with hydrogen ('injection') (use case 3b) would require significant policy support, such as a carbon price in the range of 180–600 €/tCO_2, to reach competitiveness even if the *best-case* KPI trend is met.

4.9.3 Re-electrification

The generated hydrogen may be stored and subsequently used to generate electricity (use case 3a). The analysis suggests that the levelised cost of a MWh of electricity produced by an electrolyser plus hydrogen turbine system, operating in Germany in 2030, would be in the range of 200–300 €/MWh for an electricity market with the current price volatility.[17] This production cost range is higher than the expected peak spot market wholesale price in Germany in this timeframe, so this would not be a commercially viable use case. However, this result could change if the price volatility of the electricity market increased. The development of an energy storage market which placed a higher value on 'green' stored energy could also provide a commercially viable use case.

4.9.4 Potential impact of increased price volatility

Using one projection of a possible high volatility price frequency curve, we estimated the potential impact on the cost of electrolytic hydrogen. Using simple operational strategies, the cost of electrolytic hydrogen in 2030 was reduced by as much as 0.5–1.5 €/kg_{H2}.

Increased volatility in the electricity price market may therefore provide an opportunity for electrolysis, but this is very uncertain. Our analysis could not assess all potential impacts of increased volatility, due in part to large uncertainty and divergence of opinion about its nature, and in part to the high complexity of modelling multiple possible system operation strategies and responses to any such volatility.

However, it seems logical that the type of policy frameworks that may increase electricity price volatility, such as policies for CO_2 reduction that support high penetration of renewables, may also limit the extent to which conventional (but higher CO_2) reserve technologies such as gas turbines can be used, and increase the potential for alternative technologies – such as electrolysers. These boundary conditions are significantly different from those that could be analysed in the current study

[17] This result is for the central assumption of price volatility scaled from today's market volatility. The result under assumptions of high volatility is that the produced electricity would cost an average of 137 €/MWh but could only be exported at an average price of 96 €/MWh.

and under them the competitiveness of electrolysis, even for larger scale applications, would probably look quite different.

5 Recommendations for research and development priorities

Although electrolysis has been an industrial technology for many decades, numerous opportunities exist for performance improvement and cost reduction. Some of these are technology-specific, some depend on application requirements, and others on operational strategies.

We have combined the findings of the techno-economic modelling with those of the literature review and the stakeholder feedback on key performance indicators to set high level research priorities. The recommended priorities are then discussed in the context of technology innovations, of which some are technology specific while others are technology agnostic.

We have used these findings to develop suggestions for calls for research topics in 2014 and provide a draft call.

5.1 Implications of the key performance indicator trends and techno-economic analysis

5.1.1 Efficiency

The techno-economic analysis clearly indicates that the cost of electricity is the dominant contributor to the levelised cost of hydrogen produced by conventional electrolysers, even for markets with comparatively low electricity rates[18]. This would seem to suggest that the primary objective of any electrolyser technology development program should be to improve system efficiency. However, high electrical efficiencies (defined here as required energy inputs of ≤50 kWh/kg_{H2}) have already been demonstrated and are in fact available in current commercial electrolyser products and thus no technology breakthrough is required to achieve these efficiency levels. This is also reflected in the expected key performance indicator trend, with only a modest reduction in the best-case required energy input predicted by stakeholders. In practice, these levels of energy input (≤50 kWh/kg_{H2}) are sufficiently close to the theoretical minimum value of 39.4 kWh/kg_{H2} that further improvements can only be marginal. Thus the electrical efficiency is really a system design choice rather than a technical barrier, and in practice the system efficiency must be balanced against other key performance indicators such as cost or lifetime. For example a number of small commercial electrolysers do compete effectively with high-cost logistical hydrogen even with required energy inputs in the range of 75–90 kWh/kg_{H2}, as they are designed specifically for comparatively low capital cost.

So in practice RD&D targeted exclusively at improving electrolyser efficiency is unlikely to significantly improve the commercial viability of electrolysers, whereas RD&D targeted at reducing the cost of high efficiency electrolysis could have a significant impact.

5.1.2 Lifetime

Similarly, current commercial electrolysers have already demonstrated operational lifetimes ≥60,000 hours. At this level the techno-economic analysis suggests further improvement will only have a

[18] An SOE using high temperature waste heat could in principle have a significantly reduced electricity input and hence be more competitive, but the technology is too immature to allow for any certainty from this modelling.

minimal impact on the commercial viability. However, long lifetimes are often achieved only by adding cost (e.g., more durable materials) or reducing efficiency (e.g., thicker membranes which increase resistance). So here too, RD&D targeted at achieving long lifetimes at low cost, without penalising efficiency, is more likely to improve the commercial viability of electrolysers than research targeted exclusively at increasing lifetime.

5.1.3 Cost

From the techno-economic analysis, capital cost emerges as one of the key areas for focus to improve commercial viability. In identifying research priorities, we therefore focus on areas that can reduce the capital cost of electrolysers while maintaining state of the art performance for other indicators.

5.1.4 Changing performance requirements

Other priority areas are linked to meeting the evolving requirements of emerging electrolyser applications (e.g., the need for dynamic operation to provide grid services).

5.1.5 Setting the right boundary conditions

The final area of research priorities will be in the definition of requirements, benchmark use cases, grid integration options and other boundary conditions which will help manufacturers develop a clearer picture of the performance that electrolysers will need to meet both to function correctly and be commercially viable in the roles they are expected to take in a future energy system.

5.2 Proposed approach to evaluating research proposals

From discussions with the Steering Committee and other stakeholders, and the evidence that different electrolyser technologies could play the same energy system roles, a strong consensus emerged that the technical targets of the FCH2 JU programme should be technology neutral and relatively high level (e.g. hydrogen produced at <X€/kg) and that the identification of specific technical solutions (e.g. capex, operating pressure) should be left to technology developers. The techno-economic analysis is entirely consistent with this, providing insight into the high-level system key performance indicators (specific capital cost, etc) and boundary conditions required for different use cases to be commercially viable. From a programmatic point of view, however, it is simpler to have directly measurable and even technology-specific targets so that progress and project success can be readily evaluated.

To convert the high-level system key performance indicators from the techno-economic analysis to directly measurable component and subsystem targets (capex, efficiency etc.) would, however, require detailed system design and operation studies and bottom-up system cost and performance modelling. Such analysis is entirely beyond the scope of the current study and is anyway incompatible with the notion of technology neutral research targets.

Another finding of the stakeholder consultation (Section 3.2.7, Dynamic and flexible operation) is that manufacturers lack a clear understanding of the specific technical requirements that will be required by each of the emerging electrolyser use cases.

Drawing from these various findings, we propose that the FCHJU's approach to evaluating research proposals should be to support the definition of a series of *benchmark use cases* and *benchmark boundary conditions* for the most relevant applications identified in the study. This will define a clear, common set of technical requirements that manufacturers can assess in their technology development programmes. It will also provide a framework for the FCHJU Programme Office to evaluate the relative merits of different proposed research activities in terms of their potential impact on the commercial viability of electrolysers for a given application. Finally, it will also establish a common basis for comparison of different technology options and solutions.

Here we propose draft benchmark use cases and boundary conditions, but additional work will be required to fully enumerate the benchmarks and – very importantly – to get agreement from stakeholders. The development of the benchmark use cases and boundary condition definitions has thus been included as a research area in Section 5.5 below.

5.3 Overview of research and development status in different electrolysis technologies

The development status of the different electrolysis technologies and their main technology-related challenges is summarised below.

5.3.1 Alkaline electrolysis

While alkaline electrolysis is a comparatively mature technology, improvements can still be made. Alkaline electrolysers typically support lower current densities than PEM, a limitation deriving from bubble formation in the liquid electrolyte that decreases the effective active electrode area. Manufacturers reduce the impact of this effect through advanced designs, such as zero-gap configurations of gas diffusion electrodes. Approaches to limit the effect of bubbles through applying centrifugal gravity fields, magnetic fields, ultrasound or microwaves are discussed in literature (Marini, et al., 2012; Matsushima, et al., 2009), and pursued by technology innovators. However, those approaches add complexity to the overall system and their overall system cost reduction potential is unclear at the moment.

5.3.2 PEM electrolysis

PEM typically requires expensive materials to achieve lifetimes and efficiencies comparable to commercial alkaline technologies. Most R&D activities therefore focus on material and component developments. The key challenges reported in literature and confirmed by stakeholders are cost reductions in flow-field plates (machined titanium or titanium coatings are currently typical), and the reduction of noble metals in the OER catalyst. It is worth noting that in some areas PEM electrolysis benefits from concurrent developments in PEM fuel cells, and ongoing dialogue between the industries is valuable.

5.3.3 AEM electrolysis

Anion exchange membrane electrolysis (sometimes referred to as alkaline PEM) is still in an early stage of development. For the AEM products available on the market and in development, lifetime and durability are currently the main areas of focus. The ion conductivity of the membrane is typically lower than in conventional (acidic) PEM electrolysis, which limits current densities and thus

the compactness and related cost savings. While catalysts for AEM electrolysis can generally be non-noble metals (e.g., nickel) and are hence lower cost than those in traditional PEM, catalyst application techniques and support structures are still being improved.

5.3.4 Solid oxide electrolysis

Solid oxide electrolysis (SOE) requires materials that are stable at high temperatures in corrosive environments. Typically these materials are expensive but the degradation mechanisms of less expensive alternatives are not well understood. Therefore, much current research focuses on understanding the fundamental characteristics of solid oxide electrolysis materials.

It is worth noting that developments in the Solid Oxide Fuel Cell (SOFC) research community are typically relevant to SOE as well. However, no breakthroughs are apparent that will enable the commercialisation of SOE in the coming three to five years.

5.4 Main cost contributors in electrolyser systems

Capital cost reduction is a key area of technology development activities in industrial R&D. In this section we provide an overview of system and stack cost contributors to give an indication of where the most significant cost reductions could be achieved. As discussed earlier, cost reductions need to be considered with respect to their implications on efficiency, lifetime and reliability.

While manufacturers do not share their in-house data on cost breakdowns, we have confirmed high level findings from literature through stakeholder consultation. Today, stack costs typically contribute about half of the overall costs in both alkaline and PEM electrolysis, as shown in Figure 28. However, the breakdowns shown are very generic, as system designs are manufacturer-specific and continually evolving to enable optimisation and simplification. Comparable breakdowns for AEM and high temperature electrolysis (SOE) are not available, due to the limited number of products available (AEM) and the early stage of development activities (SOE).

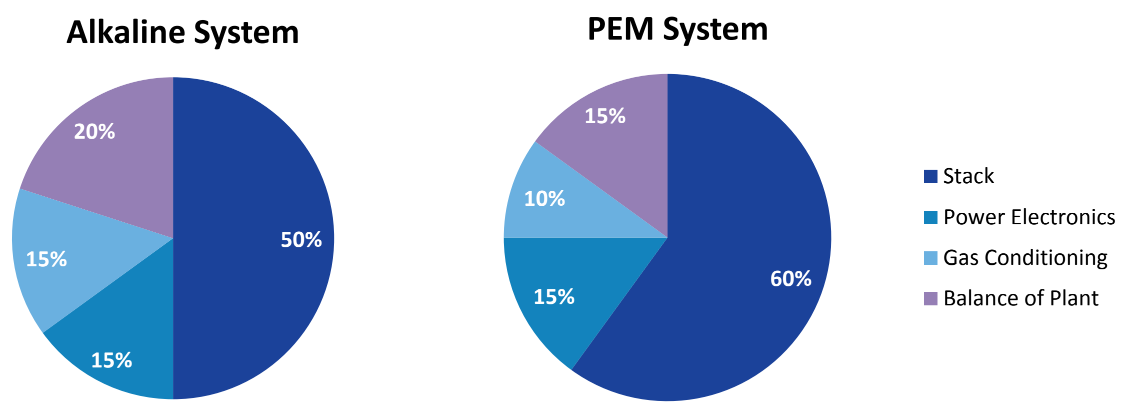


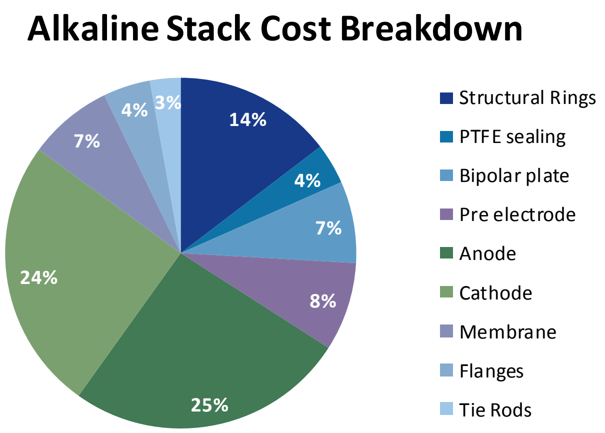
Figure 28: Indicative system cost breakdowns for alkaline and PEM electrolyser systems

(E4tech, based on various sources)

The stack level cost breakdowns are quite different for alkaline (Figure 29) and PEM (Figure 30) electrolysers. The cost of stack components in alkaline technology is largely driven by the size and weight of the components, typically larger than in PEM due to the larger cell geometries necessitated

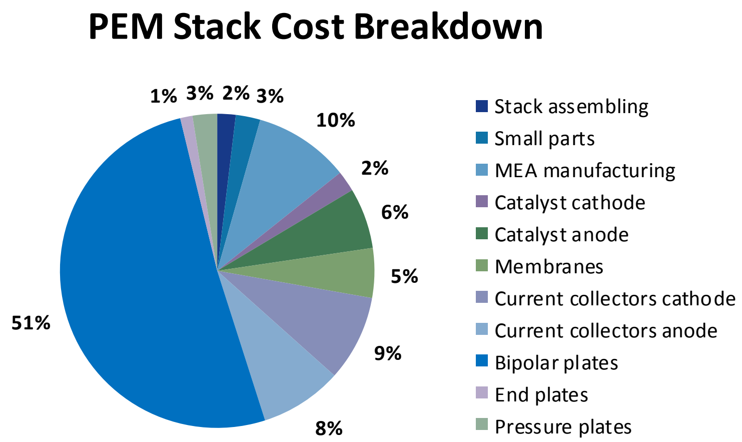
by the low current densities of contemporary systems. It is important to note that the depicted stack cost breakdowns are indicative only, and vary depending on manufacturers design choices.

In PEM electrolysis, bipolar flow field plates dominate the stack component costs. Both the material used and geometric requirements make these plates costly to manufacture, as they are typically made of thermally sintered spherically shaped titanium powder (Carmo et al., 2013). Catalysts for the anode (Oxygen Evolution Reaction, OER) and to a lesser extent the cathode (Hydrogen Evolution Reaction, HER) are important cost factors as well, but together contribute typically 10% or less of the stack cost.



(E4tech based on various sources)

Figure 29: Stack cost break down for alkaline electrolysers



(E4tech based on various sources)

Figure 30: Stack cost break down for PEM electrolysers

As with system cost breakdowns, comparable stack cost breakdowns for AEM and high temperature electrolysis (SOE) are not available, due to the limited number of products available (AEM) and the early stage of development activities (SOE).

5.5 Proposed priority research areas

Based on the review of key performance indicator development, stakeholder consultation and the outcomes of the techno-economic analysis, we have approached focus areas by grouping issues into several *problem families*. These contain both technology-specific and technology-agnostic research areas.

5.5.1 Research focused on cost reduction

5.5.1.1 Cost reduction in alkaline electrolysis

As laid out in the discussion of key performance indicators (Section 3.2), no major cost reductions due to technology innovation are expected for alkaline technology. Therefore, incremental improvements in the stack and system engineering, as well as in manufacturing, are seen as most important to reduce cost further. In addition, demonstration of multi-MW scale alkaline electrolysers with reduced footprint and greater ease of commissioning and operation is required.

At the cell level, increased current density is an important technological parameter to lower system cost. Advanced cell designs such as 'zero gap configurations' are already used in commercial products to reduce the current limiting impact of gas bubbles. To increase current densities from 0.5 A/cm² today to up to 1 A/cm² by 2030, catalysts with improved current exchange rates are seen as a key requirement. Newly developed materials to achieve these (e.g., RuO_2 and IrO_2 for the OER) have so far shown limited stability in alkaline environments. A key area of research therefore is the development of advanced catalysts with controlled morphologies and physicochemical properties, which remain stable in alkaline environments. Furthermore, research and development in membranes is still required to achieve lower gas cross-over rates and increase lifetime.

5.5.1.2 Cost reduction in PEM electrolysis

Predicted cost reductions in PEM technology will depend on progress in various research areas, reported in literature and echoed by stakeholders. The most relevant areas are introduced in this section and ordered by priority.

Cost reduction or substitution of bipolar flow field plates

Expensive materials and/or production processes are required for bipolar flow field plates that can withstand acidic environments. These plates are typically made of thermally sintered spherically shaped titanium powder (Carmo et al., 2013), and currently represent about 50% of stack costs. Advanced coatings or plate manufacturing techniques are mentioned by stakeholders as routes to significantly reduce the cost of flow field plates. Another approach is the design of flow field-free bipolar plates, which could potentially reduce related costs by one order of magnitude. Such bipolar plates are already used today in small cell geometries (25 cm² or less) (Carmo et al., 2013). Collected views from stakeholders suggest that flow field-free plate designs will remain limited to cell areas smaller than 150 cm².

Maximised active cell area to reduce specific material cost

Expensive materials and cell components are used in PEM electrolyser cells to withstand the acidic environment and enable competitive lifetimes (≥60,000 hours). Cost reduction through the use of

large cell areas ($0.5m^2$ and more) have been suggested. These would minimise the 'waste' material in plate edges and manifolds relative to the active cell area. We estimate that until other technical constraints are reached, larger single cell areas may result in ~30-50% less material than small ones at equivalent current densities. Anticipated technical challenges related to increased cell areas in PEM technology include thermal management, and uniform current distribution at high current densities.

Advanced catalysts for the OER electrode

Noble elements, typically iridium and ruthenium, are currently used in catalysts for the OER electrode to provide high corrosion resistance and catalytic activity. Iridium is not only considered an issue by stakeholders due to its high cost today, but also with respect to potential future supply constraints. As reported in literature (Carmo et al., 2013) and confirmed by manufacturer interviews, noble metal loadings have been reduced to 3 mg/cm^2 in commercial products and to about 2 mg/cm^2 in pre-commercial products, but further reductions are required. Solutions investigated today include, but are not limited to, advanced catalyst support structures, mixed metal oxides and nanostructured catalysts. For these concepts, implications for efficiency and lifetime are often not yet well understood and need further research and testing.

While manufacturers typically see reduction in catalyst cost as a lower priority for the coming years, there is a broad consensus that it will be important in achieving long-term cost reduction targets once other, more easily achieved cost reduction steps have been realised.

Alternative or advanced membrane materials and fabrication techniques

Supplier choices for membrane materials are currently limited, and very few electrolyser companies have developed their own membrane technology. The standard product widely used in industry is based on inherently costly fluorine chemistry. Various lower-cost materials are in research and development, often with the aim of concurrently improving the ion exchange characteristics and mechanical stability. As the membrane contributes about as much to the stack cost as the OER catalysts (roughly 5%), research and development in this area is seen as a key priority.

Advanced catalysts for the HER electrode

Expensive noble elements in the HER electrode are used to achieve high corrosion resistance and high catalytic activity, with palladium and platinum based catalysts typically used today. Literature (Carmo et al., 2013) and manufacturer interviews confirm that noble metal loadings have been reduced to 1 mg/cm^2 in commercial products and to 0.5 mg/cm^2 in pre-commercial products. Various routes to further reduce loadings or replace noble metals in HER catalysts are being researched and are broadly similar to the concepts pursued for OER catalysts (see above). Overall, catalyst-related cost reductions at the HER electrode are not seen as critical, as the OER electrode catalysts have higher loadings (2-3 mg/cm^2). Nevertheless HER catalysts are expected to become a key priority in the long term, when other major cost reduction steps have been taken.

5.5.1.3 Cost reduction in AEM electrolysis

An important cost reduction potential for AEM technology over PEM is in the non-noble metals (e.g., nickel) that can be used as catalysts in alkaline environments. However, this advantage can only be

realised if the ion conductivity of the membrane can be improved, as this currently limits AEM to current densities below 0.5 A/cm².

5.5.1.4 Cost reduction in solid oxide electrolysis (SOE)

While several research areas for SOE should lead to reduced cost, concrete impacts cannot be assessed as reliable cost information is lacking. To overcome current uncertainties in the economic assessment of SOE technology, one proposed R&D area is therefore more specific techno-economic assessment based on early pilot projects. It is recommended that aspects related to the viability of co-electrolysis are specifically included in such research projects.

Further research areas in SOE are in the ongoing development of corrosion- and high temperature-resistant materials and seals, and their cost reduction.

5.5.1.5 Cost engineering

The small size and the structure of the electrolyser industry mean that cost reduction through design for manufacture, supply chain management and other relatively prosaic methods has not been fully achieved. This is typically manufacturer-specific and mainly appropriate to more significant scale-up, and we do not see it as a typical FCHJU activity. However, developments in these areas should be encouraged, and potentially supported if they fit appropriately into a wider project.

5.5.2 Research focused on dynamic operation capability

One outcome of the literature review and stakeholder consultation on key performance indicators has been that most dynamic operation requirements imposed by the likely future role of electrolysis are already met by some commercially available systems, or that system design solutions exist – at least in the manufacturers’ labs. A specific challenge for alkaline systems is to reach comparable part-load operation flexibility as PEM. This can be addressed both via advanced membrane materials and system design adaption.

The suggested focus for research and development activities is in the following areas:

- Optimisation of system components for quick response to load changes. This may have implications on stack design, optimisation of pumps, gas-water separators, and pressure control for fast-ramping regimes.
- System designs that enable advantage to be taken of increased cell efficiency when operating in part load mode (through lower current density). This typically includes minimisation of parasitic loads in the system components (e.g., efficient part load operation of pumps).
- Investigation of impacts on lifetime caused by dynamic operation. The definition of benchmark requirements and testing cycles for dynamic applications will enable this research (see also 5.5.4)

5.5.3 Pressurised operation

The techno-economic analysis has confirmed a modest potential cost advantage of pressurised electrolysis, depending on system design. However, it is important to note that intrinsic cost differences between a pressurised and an unpressurised electrolyser were not available from the data gathered, and many technologies and strategies exist to produce high pressure hydrogen.

Compared to other capital cost contributors and especially compared to the impact of electricity cost, pressurised electrolyser operation appears as a secondary development priority with no significant impact on the economic viability of electrolysis in the long term.

5.5.4 Definition of requirements, benchmark use cases, test cycles and other boundary conditions

As previously discussed, the stakeholders underlined that the requirements of the emerging applications proposed for electrolysers are not yet clear. This makes it challenging to determine the ideal performance characteristics for each potential application. The TEA has also underlined the importance of boundary conditions, such as electricity and natural gas prices and the volatility of future electricity prices, to the commercial viability of the electrolyser use cases. The future values of such boundary conditions and requirements are inherently uncertain, being strongly dependent on the evolution of policy, regulations and the overall energy system.

The development of benchmark requirements, use cases, boundary conditions and standard operation and test cycles could thus be very helpful in enabling the electrolyser industry to select research and development priorities and directions.

The benchmark data would need to include elements such as:

- *Definition of each relevant use case*, including system technical specifications, value proposition, operational strategy and counterfactual
- *Standard boundary conditions* such as energy prices, relevant energy system characteristics, energy and energy service market characteristics, etc.
- *Standard operating and testing cycles* relevant to the most promising use cases

The data will not be a representation of any single ‘real’ system. However, they should be developed in agreement with stakeholders to provide a common point of reference and common baseline for evaluation. Even the process of agreeing the data would reduce its uncertainty by drawing on stakeholder expertise, and having such benchmark data would further serve to:

- Build stakeholder agreement
- Allow prioritisation of research and development activities and targeting of these activities to the most promising applications
- Provide a common basis for evaluating different technology options

5.5.5 Plausible business models; harmonised regulations, codes and standards

Business models *per se* must be the preserve of the individual competing organisations or consortia. However, the uncertainty and complexity demonstrated in the TEA modelling suggests that better understanding of aspects other than technology development and performance is essential. This would include developing an evidence base for defining policy support measures and for demonstrating where electrolysers can add value in future energy systems, which may be in part through demonstration but also through modelling and simulation. If hydrogen for refuelling is indeed a major opportunity, further specific demonstration and understanding of novel electrolyser/filling station concepts, and integrated grid services and filling station systems would also be of value.

Plausible business models are also heavily and varyingly affected by regulations, codes and standards. Not only do these vary by jurisdiction, but often also by size of installation and by application. Understanding better what these standards are, how much variation exists, and harmonising them wherever possible could be very supportive of future electrolyser deployment.

5.6 Proposed FCH 2 JU research topics for 2014

We have used the requirements for commercial viability of electrolysis to define the technology development targets and thus the research priorities. Ultimately, the system implications of any technology development will drive the extent to which water electrolysis can fulfil its envisaged role in the energy system.

We have thus chosen to organise the research topics in a top-down manner, starting with topics related to the energy system and working our way down to those related to specific electrolyser systems or chemistries. The list of topics is not intended to be fully exhaustive but to encompass the main areas which we believe are necessary to support the deployment of water electrolysis. In many cases more than one item will be an element of a call.

Energy system level topics

5.6.1 Grid- and energy system-integration of electrolysers

Many issues surrounding the grid integration of electrolysers are currently uncertain and require study and analysis. One such area, repeatedly mentioned by stakeholders, is the need to identify and clarify the electrolyser system performance specifications which are required to provide grid services. The TEA suggests that the provision of both reserve and frequency response services will likely be key to the commercial viability of electrolysers, and the detailed requirements for both types of service need to be well understood.

The size of the potential market for such grid services is unclear. Estimating the size and value of balancing service markets both now and in the future, allowing for evolution in the grid mix and structure, is necessary to be able to assess the likely size of the electrolyser market and to develop a better deployment roadmap.

More generally, an evidence base around the role of electrolysis in the energy systems of the future is required. Simulation and analysis of the future electricity and broader energy systems could be instrumental in building this evidence base. Topics of particular interest would be the impact of grid transformation on electricity price volatility and grid stability. Such analysis would also enable clarification of the other topics mentioned above, such as the size of grid services market or the technical requirements.

Specific potential call topics could thus be for projects to:

- Develop detailed requirements definitions for the electrolyser performance specifications required to provide grid services
- Estimate the size and value of grid service markets in different EU countries and their evolution over time

- Model the future energy system to develop an evidence base around the role of electrolysis in the future energy system. The evolution of electricity price volatility and demand for grid services would be specific topics to explore.

5.6.2 Definition of benchmarks

As discussed in Section 5.2, benchmarks are required in a number of areas to support both the electrolyser technology development effort and the FCHJU's management of its research programme.

1. The first area in which benchmarks would be useful is in the definition of pertinent use cases. These use case definitions should include fully specified system requirements, the proposed operational strategy, the value proposition for each of the relevant actors along the value chain, and the counterfactual(s) against which electrolysers would be competing in the application. This activity is clearly closely related to the definition of performance requirements discussed in Section 5.6.1.

   An extension of this area would be the definition of standard operating and test cycles. Such standardized cycles would provide clarity to technology developers on performance requirements, provide a common basis to compare system performance, and support the development of regulations, codes and standards.
2. A second area for the definition of benchmarks is the boundary conditions such as energy prices, energy system characteristics, energy service market characteristics, and the policy and regulatory framework. This information is also required to enable the energy system analysis discussed in Section 5.6.1, and to provide a common basis for the evaluation of options and for decision making.
3. A third area is in the definition of a standard approach and methodology to conducting the techno-economic analysis of the options being evaluated. These benchmarks would build on the previous two areas and would allow technology options and research activities to be evaluated in terms of the high level system performance metrics (such as levelised cost of hydrogen) which are considered critical to showing the commercial competitiveness of the technology.

Specific potential call topics could thus be projects to:

- Define benchmark use cases. Each definition should include system requirements, operational strategies, value propositions for all required actors, and counterfactuals;
- Define standard operating and test cycles for energy system applications of electrolysers;
- Define a standard set of boundary conditions to support other analyses. These boundary conditions should include energy prices, energy system characteristics, energy service market characteristics, and the policy and regulatory framework;
- Define a standard approach and methodology to conducting techno-economic assessments of electrolyser applications.

5.6.3 Regulatory issues

A wide range of regulatory barriers oppose the integration of electrolysers into the grid and the ability of electrolysers to provide grid services. As a simple example, a number of the countries

considered during this study do not allow load shedding to be considered as a balancing service. Since the TEA suggests that the provision of grid services will likely be key to the commercial viability of water electrolysis, studies to identify and examine the regulatory barriers to electrolyser deployment would be extremely useful.

Regulation could also play a central role in defining the green credentials of electrolytic hydrogen. The ability of electrolysis to produce very low carbon hydrogen from low carbon electricity is one of the key drivers behind interest in electrolysis. However, electrolyser deployment is expected to occur during the same timeframe as grid decarbonisation. During this potentially long transition phase, regulatory and policy issues surrounding the use of green electricity and green hydrogen – such as certificates, credits, and double counting – could either promote or hinder the deployment of electrolysers. The issue could be further complicated in refuelling applications where electrolysis would sit at a nexus between the power and transportation sectors and policies. Here too, studies to develop a knowledge base on the issues and challenges could be very beneficial.

Specific potential call topics could thus be projects to:

- Identify and analyse the regulatory barriers to electrolyser deployment – in particular as regards the provision of grid services, interfaces to the grid, and deployment in distributed refuelling applications
- Identify and analyse potential issues in the domain of green certificates and credits in the context of electrolytic hydrogen production for both transport and industrial uses

5.6.4 Development and harmonisation of standards

Large scale deployment of electrolysers, particularly in distributed applications, will inevitably depend on the development of standards. Considerable attention has already been paid to the development of standards for hydrogen refuelling. However, the grid interface of electrolysers has not yet received the same level of attention. There is every expectation that electrolysers will be deployed across the EU in a number of different possible end uses, thus it will be important to develop and harmonise standards in the different jurisdictions and across the various applications.

A potential call topic could thus be a project to:

- Support the development and harmonisation of standards by developing reference requirements and specifications for grid and refuelling infrastructure interfaces across different end uses and jurisdictions

Supply and value chain level topics

5.6.5 Deployment and supply chain development challenges

The results of the TEA suggest that driving down electrolyser system cost will contribute significantly to the commercial viability of the technology. Stakeholders agree that there is significant potential for cost reduction. However, realising this potential requires scale-up of electrolyser manufacture and rationalisation of the supply chain, which can only be achieved if the volume of deployment is sufficient. Analysis of the electrolyser and supply chain roll-out required to meet the deployment and cost targets—including assessments of the investments required to effect the deployment while working down the cost curve—would serve as a foundation to the development of a deployment

roadmap for the industry. Since the electrolyser and hydrogen energy industries are international, this analysis should include non-European regions at some level.

A potential call topic could thus be a project to:

- Validate that the expected or intended deployment targets are sufficient to support the manufacturing scale-up required to achieve the hoped for cost reductions. Another element of such a study could be to estimate the investment required in both production infrastructure and electrolyser deployment to achieve the deployment and cost reduction targets

Electrolyser system level topics

At the electrolyser system level there are both topics that apply generally to all chemistries as well as chemistry-specific topics. These are discussed in turn below.

5.6.6 General electrolyser system topics

While there have been lab and initial pilot demonstrations of electrolysers performing in the types of operational modes that are expected to be required for integration in to the energy system, there is still uncertainty about the performance realisable under real world usage conditions. The development of a knowledge base in this area will be instrumental in clarifying the role that electrolysers can play in the future energy system.

A related area of uncertainty regards the dynamic performance of electrolysers and the system configurations required to achieve this. Developments in stack design as well as in the optimisation of balance of plant components are expected to contribute significantly to electrolyser's dynamic performance characteristics. Similarly, optimisation of balance of plant components to reduce parasitic loads during part load operation is seen as a potentially fruitful path to pursue.

Another significant area is in characterising and further developing the understanding of degradation mechanisms, particularly under dynamic operation. The findings from the TEA underline the importance of system electrical efficiency given the dominant contribution of electricity costs to the cost of produced hydrogen. Electrolyser stacks are typically considered to reach the end of their life when their efficiency has degraded by 10% points from the nominal value. Assuming linear degradation, this corresponds to an effective reduction by 5% points in average efficiency over the life of the stack, which could have a significant impact on the commercial viability. Technology advancements that can reduce this efficiency penalty are of significant interest.

Finally, while this topic is unlikely to warrant a standalone call, it is important not to ignore the significant cost reductions and system improvements that can be achieved through system engineering. As part of other research activities, technology developers could be asked to demonstrate how their proposed improvements contribute to objectives such as system simplification or minimisation of material use or cost, or demonstrate a path to volume manufacturing.

Specific potential call topics could thus be projects to:

- Validate electrolyser system performance in real world usage, while simultaneously meeting the requirements for the provision of grid services *and* for an end use such as hydrogen refuelling
- Develop and demonstrate electrolyser system designs optimised for dynamic operation including optimised stack designs, pumps, gas-water separators and controls to enable fast-ramping operation
- Develop and demonstrate electrolyser system designs that enable high efficiency operation over a wide range of load conditions
- Characterise and improve understanding of degradation and degradation mechanisms, particularly under dynamic operation
- Develop and demonstrate electrolyser systems with low degradation, particularly while operating dynamically
- Develop and demonstrate system design concepts that contribute to system simplification, cost reduction, material use minimisation or that put in place a path to volume manufacturing

5.6.7 Alkaline electrolysis topics

As discussed in Section 5.5.1.1, the main opportunities for cost reduction in alkaline electrolysis are seen in improving the current density and in system engineering.

Specific potential call topics could be projects to:

- Develop and demonstrate improved catalysts materials that enable higher current densities (target ≥1 A/cm2)
- Develop and demonstrate improved membrane materials which achieve low gas crossover rates, for improved part load operation

5.6.8 PEM topics

As discussed in Section 5.5.1.2, cost reduction for PEM electrolysers has a number of promising directions.

Specific potential call topics could be projects to:

- Develop and demonstrate concepts for the cost reduction or substitution of bipolar flow field plates. Topics could include advanced coatings and manufacturing techniques, and the demonstration of a path to low cost volume manufacturing
- Develop and demonstrate large cell area systems to maximise the ratio of active to total cell area and reduce specific material cost. This research is likely to require supporting technology development to address challenges in thermal management and current distribution uniformity
- Develop and demonstrate advanced, reduced cost catalysts for both OER and HER electrodes including such concepts as advanced catalyst support structures, mixed metal oxides and nano-structured catalysts
- Develop and demonstrate alternative or advanced membrane materials and fabrication techniques with the aim of reducing cost, improving ion exchange characteristics and improving the mechanical stability

5.6.9 AEM topics

As discussed in Section 5.3.3, AEM technology is less mature than PEM or alkaline. On the cost front, AEM technology is expected to benefit from the use of lower cost non-noble metal catalysts. However, the current density in available systems is limited by the membrane conductivity to values below about 0.5 A/cm^2. Increasing the membrane conductivity as well as its durability are seen as the current top research priorities, within the context of demonstrating AEM's role in future energy systems.

A potential call topic could thus be a project to:

- Develop and demonstrate improved membrane materials and manufacturing techniques that enable higher current densities (target ≥1 A/cm^2) suitable for operational lifetimes ≥60,000 hours, and show their implications for future systems

5.6.10 SOE topics

Solid oxide electrolysers are currently at TRL 2-4, so a considerable amount of development will be required before the technology can approach commercial deployment. Nonetheless, several areas could be of interest to the FCHJU.

Specific potential call topics could be projects to:

- Demonstrate full system operation and begin to develop dependable system cost data
- Review and analyse the business case for co-electrolysis and other novel use cases enabled by SOE high temperature operation
- Develop and demonstrate advanced, low-cost, corrosion and temperature resistant materials

5.7 Draft call for a demonstration project

The analysis we have conducted shows strongly that the broad 'Grid Services' context is very important in setting and understanding electrolyser performance characteristics. The TEA shows that:

- Electrolysers have the potential to help mitigate the increasing challenges of intermittency (of renewables and end uses) on grids
- The role of hydrogen is a combination of providing valuable services to the grid in addition to getting a reasonably high value for the hydrogen produced
- This requires demonstration of the role of electrolysers in providing grid services AND servicing a high value market for the hydrogen produced.

We therefore propose the call should include different technologies and regulatory regimes, while strongly promoting cross-over learning. It should also demonstrate the realisation of revenues from providing one or more grid benefits.

A draft call text is provided as Appendix 3.

6 Technology development roadmap

The stakeholder views on the role of electrolysis in the future energy system, as discussed in Section 2, are that electrolysers are expected to take on new roles in transport, energy storage and grid

services, and eventually also in industrial applications. Figure 31 shows a schematic representation of the views expressed, covering the timeframe from now until 2030.

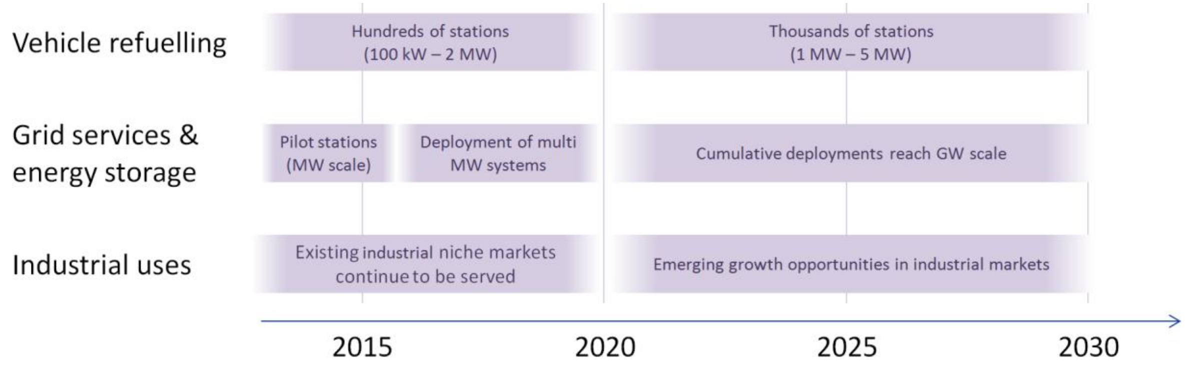


Figure 31: Stakeholder views of the expected development of electrolyser applications

However, the findings from the TEA suggest a more nuanced situation. The TEA finds that for energy storage applications such as re-electrification and hydrogen injection into the gas grid (TEA use cases 3a and 3b) electrolysers struggle to be commercially viable against competing alternatives.

Conversely, the TEA finds that, at least in markets with low industrial electricity rates, electrolysers for the distributed production of hydrogen for refuelling applications can be commercially competitive with hydrogen produced in centralised SMRs. One element required to reach this commercial competitiveness is the provision of grid balancing services to reduce the effective cost of the hydrogen produced. This suggests that the vehicle refuelling and grid service applications will likely not be independent. Figure 32 therefore shows a modified version of the application evolution schematic that groups the grid service and vehicle refuelling applications.

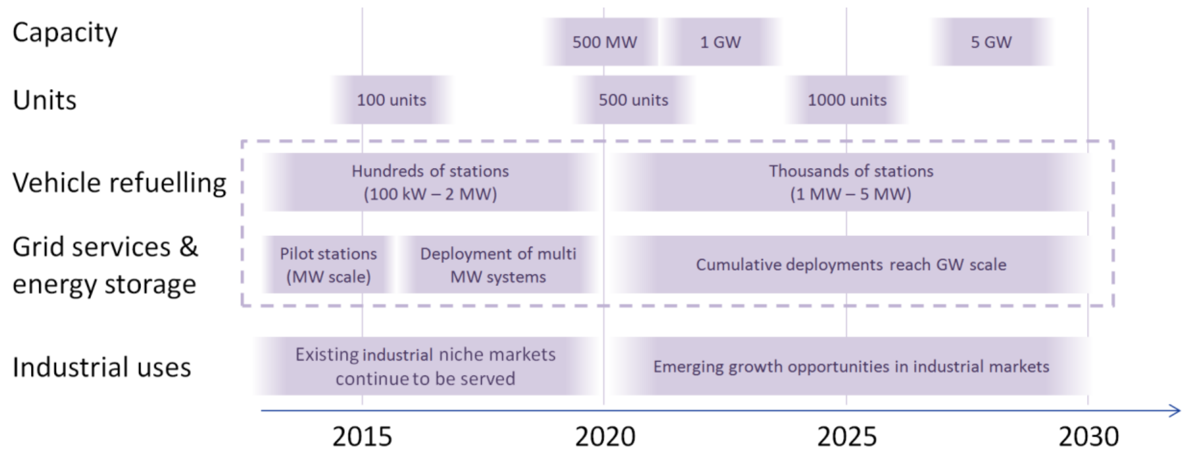


Figure 32: Schematic of the expected development of electrolyser applications that reflects the TEA findings

Nonetheless, stakeholder views on the scale of electrolyser deployment do not seem to be inconsistent with this expected evolution of the applications. Figure 32 also shows a set of indicative capacity and unit deployment milestones. These milestones are clearly not intended to be prescriptive but represent perhaps a slightly aggressive vision of electrolyser deployment in the next decades, resting primarily on the deployment of refuelling infrastructure for hydrogen mobility. For

comparison, the H2 Mobility initiative suggests that 400 hydrogen refuelling stations will be deployed in Germany between now and 2023 (H2 Mobility Initiative, 2013). Thus the 500 unit deployment milestone in the early 2020s would be consistent with the realisation of hydrogen infrastructure in a few large EU countries in which electrolysis is chosen to provide a significant fraction of the required hydrogen.

Other factors that could further support the deployment of electrolysers would be favourable regulatory or policy frameworks – such as low industrial electricity rates and high carbon prices – or increases in electricity price volatility, which would expand the range of countries and applications for which electrolysers could be commercially viable.

Improvements in the cost and performance of electrolyser systems will support the broader deployment of electrolysis by improving the commercial viability. At the same time, technology development will be dependent on deployment success, as it is the deployment that will drive the maturation of the system engineering and manufacturing base and lead to lower cost, improved performance electrolysis systems. Table 2 indicates the anticipated development in key performance indicators that underpins – and is driven by – the rollout discussed above.

Table 2: Expected evolution of key electrolyser system performance indicators

	2015	2020	2025	2030
System cost (€/kW)	950–1,600	600–1,000	600–900	600–800
Indicative stack size (MW)		1-3 MW		2-4 MW
Indicative large system size (MW)	≈3	≈5	≈6	≈7
Electrical input (kWh/kg_{H2})	≈56	≈52	≈51	≈50
Stack life (khr)	65–80	75–95	75–95	80–95

7 References

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8 List of Acronyms

AEM	Anion Exchange Membrane, also often referred to as alkaline PEM (alkaline polymer electrolyte membrane).
BS	Balancing Services
Capex	Capital expenditure
DG ENER	Directorate-General for Energy a Directorate-General of the European Commission
FTE	Full-time equivalent
HER	Hydrogen Evolution Reaction. Cathode side reaction (reduction) in an electrolyser where hydrogen is produced.
HHV	Higher Heating Value (for hydrogen: 39.4 kWh/kg)
HRS	Hydrogen Refuelling Station
KPI	Key Performance Indicator
LHV	Lower Heating Value (for hydrogen: 33.3 kWh/kg)
MEA	Membrane Electrode Assembly
OER	Oxygen Evolution Reaction. Anode side reaction (oxidation) in an electrolyser where oxygen is produced.
Opex	Operating expenditure
PEM	In this study we use PEM for Proton Exchange Membrane, as opposed to Anion Exchange Membrane (AEM). Both proton and anion exchange membrane can be referred to as PEM, using PEM for Polymer Electrolyte Membrane.
PM	Price minimisation
ppm	Parts per million
PTFE	Polytetrafluorethylene
RD&D	Research, development and demonstration
RG	Renewable Generator
ROCs	Renewables Obligations Certificates
SAE	Society of Automotive Engineers
SMR	Steam Methane Reforming
SOE	Solid Oxide Electrolysis or Solid Oxide Electrolysis Cell (SOEC), an electrolysis device operating at high temperatures (typically 500-850°C) in which ceramics are used as a solid electrolyte.
TEA	Techno-economic analysis
TUM	Technische Universität München
UK	United Kingdom
US DoE	United States Department of Energy
WE	Water electrolyser

9 Units and conversions

Table 3 and Table 4 show conversion factors between commonly used units for measuring quantities of hydrogen.

Weight	Volume at STP [a]	Energy Content	Equivalent volume of gasoline [b]
0.09 g	0.001 Nm^3 (1 litre)	0.00351 kWh	0.0003 litres
0.09 kg	1 Nm^3	3.54 kWh	0.36 litres
1 kg	11.13 Nm^3	39.4 kWh	4 litres

[a] STP = Standard temperature and pressure (0°C and 1atm)

[b] Gasoline equivalent calculated using SHEC labs fuel energy equivalence calculator [19]

Table 3: Conversion factors between hydrogen quantities

Mass Flow Rate		Volumetric Flow Rate	
41.7 g/h	1 kg/day	0.46 Nm^3/h	11.13 Nm^3/day
1 kg/h	24 kg/day	11.13 Nm^3/h	267.12 Nm^3/day
41.7 kg/h	1 t/day	464.12 Nm^3/h	11,130 Nm^3/day
1 t/h	24 t/day	11,130 Nm^3/h	267,120 Nm^3/day

Table 4: Conversion factors between hydrogen flow rates

[19] www.shecenergy.com/calc/fuel_energy_equivalence

Appendices

Appendix 1

Stakeholder organisations and academics who responded to our contact requests

Industry and utilities	Technology focus
Fundación Hidrógeno Aragón	-
Acta	AEM
AREVA	PEM
Diamond Lite	PEM
E.ON Gas Storage	-
Haldor Topsoe	SOE
Hydrogenics	Alkaline & PEM
IHT	Alkaline
ITM Power	PEM & AEM
MyPhy	Alkaline
NEL	Alkaline
Proton OnSite	PEM
Siemens	PEM
Vattenfall Europe Innovation	-

Academics	Technology focus
Ulrich Stimming **Technische Universität München**	-
Nigel Brandon **Imperial College London**	SOE
Marcello Carmo **Forschungszentrum Juelich**	PEM
Ulrich Fischer **Technische Universität Cottbus**	Alkaline
Mogens Mogensen **Danmarks Tekniske Universitet (DTU)**	SOE
Gerda Reiter **Johannes Kepler Universität Linz**	-
Robert Slade **Surrey University**	AEM
Magnus Thomassen **SINTEF Norway**	PEM

Appendix 2

List of electrolyser suppliers (not exhaustive)

The following list contains electrolyser manufacturers and a selection of key performance indicators of their products collected ‘as is’ from technical data sheets. System boundaries for efficiency data are not harmonised and may differ among different manufacturers. The authors take no responsibility for the accuracy of the data, and it should be noted that the list of companies is not exhaustive.

Company	Country	Technology	Product	Capacity (Nm3/hr)	H_2 output pressure (barg)	H_2 purity (%)	Electricity consumption (kWh/kg)	Electric LHV efficiency (%)
Acta	Italy	AEM	EL1000	1	29	99.94	53.2	63%
AREVA	France	PEM	Development	20	35	99.9995	55.6	60%
CETH2	France	PEM	E60 cluster	240	14	99.9	54.5	61%
ELT Elektrolyse Technik	Germany	Alkaline	Customised	330	Atmos-pheric	99.85	51	65%
Erredue s.r.l	Italy	Alkaline	G256	170	30	99.5	59.5	56%
H2 Nitidor	Italy	Alkaline	200Nm3/hr	200	30	99.9	52.3	64%
H-TEC SYSTEMS	Germany	PEM	EL30/144	3.6	29	N/A	55.6	60%
Hydrogenics	Belgium, Canada	Alkaline (PEM in dev.)	HyStat60	60	10	99.998	57.8	58%
Idroenergy	Italy	Alkaline	Model120	80	5	99.5	52.4	64%
IHT Industrie Haute Technologie	Switzerland	Alkaline	Customised	760 [20]	31	N/A	51.2	65%
ITM Power	UK	PEM (AEM in dev.)	HPac40	2.4	15	99.99	53.4	62%
NEL Hydrogen	Norway	Alkaline	Customised	485	Atmos-pheric	>99.8	50	67%
McPhy	Germany	Alkaline	60Nm3/h container	60	10	>99.3	57.8	58%
Proton OnSite	USA	PEM	Hogen C30	30	30	99.9998	64.5	52%
Siemens	Germany	PEM	SILYZER200[21]	~250	N/A	N/A	~60	~55%
Teledyne Energy Systems	USA	Alkaline	SLM 1000	56	10	99.9998	N/A	N/A
Wasserelektrolyse Hydrotechnik	Germany	Alkaline	EV150	225	Atmos-pheric	99.9	58.7	57%

[20] Systems are currently not available on the market. IHT is planning to commercialise products with new membrane designs.

[21] Delivery of first systems scheduled for beginning of 2015. For more information see www.siemens.com/hydrogen-electrolyzer

Appendix 3

Draft call for a demonstration project

<u>Topic SP1-JTI-FCH.2014.A.B: Topic Title</u>

Specific challenge:

Recent analysis by the FCHJU[22] has demonstrated the potential of electrolysers to play an important role in meeting the demands for hydrogen from the transport and industrial sectors.

However, in order for electrolysers to play this role, it is important that the cost of hydrogen produced competes with alternative sources. While some policy support may be directed at electrolysers in terms of their "green" credentials, in the longer term they must compete in unsubsidised markets.

The cost and performance of electrolysers is developing through time and this will help to reduce the cost of electrolytic hydrogen. However, cost modelling suggests that in addition to the effects achieved at the electrolyser level, competitive hydrogen will also require a combination of low cost input electricity as well as revenues from the provision of additional services to the electricity grid. The additional services which electrolysers may provide to the grid include:

- *Balancing services* – where electrolysers are available for short term and rapid control by grid operators to balance supply and demand and hence keep electrical grids stable – these services are valued at a Transmission and increasingly at a Distribution level on grid systems
- *Price arbitrage* – where the electrolyser is modulated to take advantage of different electricity prices at different times of the day
- *Avoiding grid connection or reinforcement* – where electrolysers are installed instead of new electrical connections (either for a new generator connection, or for a constrained network in a zone of high generation).
- *Other benefits* – for example the ability to absorb reactive power.

The provision of these grid services by electrolysers has been demonstrated in numerous theoretical studies and a few small scale demonstration projects. However, there have been very few demonstrations of electrolysers operating in the actual provision of these services, and on a scale which would be relevant to grid operators. Furthermore, little evidence has been gathered of the way electrolysers could operate to maximise their benefits to the grid (and revenues to their operators) across European member states and their electricity markets.

This demonstration call seeks proposals which demonstrate state of the art electrolyser technologies providing and receiving revenue by providing these balancing services, whilst satisfying (and receiving revenues from) an end use for the hydrogen generated.

[22] Study on development of water electrolysis in the EU, FCHJU 2014 (E4tech and Element Energy)

Scope: The overall objectives of the call include an essential element of information gathering and dissemination, enabling the development of electrolyser systems capable of providing such services. While electrolysers themselves have a high TRL, the complexity and immaturity of this proposed integrated system leads to a TRL closer to 5, which could be elevated to TRL7.

The scope of the project is hence to deploy and monitor state of the art electrolyser systems, configured to attract revenues from grid services in addition to providing hydrogen for an end user, in at least two member states. A European consortium will develop the project, including partners able to provide:

- the necessary contractual and commercial expertise to access revenues from the grid services
- technical expertise for the design and operation of the electrolyser and associated balance of plant
- representatives of the downstream users of hydrogen generated

To maximise the impact of the study, consortia are encouraged to look to partner with already funded demonstration projects involving electrolyser deployment, who would be able to provide additional data and reference sites for the operation of electrolysers in these grid services modes.

Balancing services

- Electrolyser system operators will demonstrate that they are able to benefit from at least one of the grid services revenue streams discussed above. Here, the consortium will demonstrate that they are able to obtain these revenues by entering into commercial contracts with the grid operators or utilities who value these services

Electrolyser and balance of system requirements

- State of the art electrolysers will be installed and operated for a minimum period of two years
- Electrolysers and their balance of plant will be designed to access these services whilst meeting the need of their end users
- Electrolysers systems will demonstrate a sufficient level of responsiveness to meet the requirements of the grid services they will seek to offer (e.g. rapid modulation, rapid start, as required by the services offered to the grid)
- The size of the electrolysers demonstrated will be clearly sufficient to access revenues from the grid services identified for each demonstration site – if appropriate, aggregation of electrolyser demand with other electrolysers (or other demands) can be considered, if this allows access to higher value grid services. It is anticipated that electrolysers will have a minimum size of 1MW, but smaller systems can be considered if their ability to access grid services can be demonstrated.
- The balance of plant to store and process hydrogen from the electrolyser is within the scope of this call

Hydrogen end users

- A plausible end use for hydrogen will be defined for each demonstration site.
- Consortia will provide evidence that this demand is in place and that the electrolyser operators will achieve meaningful revenues from selling hydrogen to this end use during the project. All energy (transport, heat, electrical) and industrial end uses for the hydrogen are within scope, but consortia should demonstrate that a profitable business case for the proposed electrolyser-end use combination can be achieved in the medium term.
- The end uses themselves should be identified, but will not be funded by the FCHJU under this call. Proposers may wish to consider integrating applications under this call with other call topics involving end uses for hydrogen.

Business models

- Consortia will demonstrate an organisational structure for the ownership of the electrolyser and the associated arrangements with grid operators/utilities and end users
- In their proposals, consortia will outline the conditions under which this configuration could lead to a profitable business case for all actors in the medium term. During the project, consortia are expected to carry out techno-economic work to assess the long term business case for the electrolyser, grid services, end use combination considered in the demonstration projects.

Expected impact:

The project will lead to deployment of at least two large electrolysers, operating on a continuous basis in an energy services mode for a minimum period of two years. Electrolysers should achieve the following technical targets:

- Electrolysers
  - Capital cost for the conventional parts of the system should be below 1,000 €/kW (Alkaline) and 1,500 €/kW (PEM)
  - Electrolyser manufacturers should demonstrate a clear pathway to further reductions in costs towards any FCHJU 2030 targets
  - Electrolyser system efficiency (including system balance of plant, power electronics, cooling, drying, purification) should be <53kWh$_{AC}$/kg
  - Degradation consistent with 60,000 hours life (in the targeted operating mode) before the stack efficiency is reduced by 10% from the design efficiency
- Balance of plant
  - Appropriate compression, storage and dispensing equipment for the end use and electrolyser operating mode (or modes) identified. Given that a number of end uses are possible, the consortium should demonstrate that the balance of plant is provided at a

cost and performance level consistent with best in class applications serving the same end use

  - Balance of plant should be designed for at least 60,000 hours of continuous operation

- Controls, grid interface
  - An appropriate control system will be designed to allow the full electrolyser system to optimise its operation against the (potentially competing) requirements to satisfy the end use and the grid services commitments
  - Appropriate communications to receive signals from the grid relating to the grid services (e.g. response signals, or frequency monitoring devices) will be installed. Where possible, these should be based on industry standard protocols.

A monitoring program will establish data on the performance of the electrolyser systems and their balance of plant on a suitably short timestep against these metrics, as well as providing data on the evolution of the commercial arrangements on an appropriate timestep (e.g. half hourly if the electrolysers are interacting with half-hourly electricity markets). An aggregated version of this dataset will be made available to the FCHJU for their program evaluation activities.

The consortium will ensure that cross cutting studies are included in the project, in order to generate learning from across the demonstration sites, on topics including:

- Technical lessons learnt in the design and operation of these electrolyser systems
- The environmental performance of the system – with a particular attention to the CO_2 intensity of the hydrogen produced, which should include an understanding of the CO_2 impact of the grid services mode selected
- Techno-economic analysis of the performance of these systems
- Projections of the value and size of the markets addressed by the project across Europe
- Assessment of the contractual arrangements required to access the balancing services and operate the electrolyser systems
- Assessment of the RCS implications of these systems and any issues identified in obtaining consents to operate the system
- Recommendations for policy makers and regulators on measures required to stimulate the market for these systems

Public-facing versions of these ‘lessons learnt’ reports should be prepared and disseminated across Europe and potentially wider.

The consortium should include outreach and dissemination activities to share the results of the project with European decision makers in this sector, including regulators, grid operators, utilities and policy makers.

Budget: Indicative total cost could approach €20 million. However, the budget should be defined by the FCHJU in the context of the total programme

Consortium: Consortia should include the complete value chain relevant to this business case, including: Electrolyser developers, Network operators, Electrolyser system operators, Utilities (i.e. market participants) and Hydrogen und users. In addition, the consortia may benefit from the inclusion of research partners to carry out cross cutting studies and national electricity system regulators

Type of action: Innovation

Appendix 4

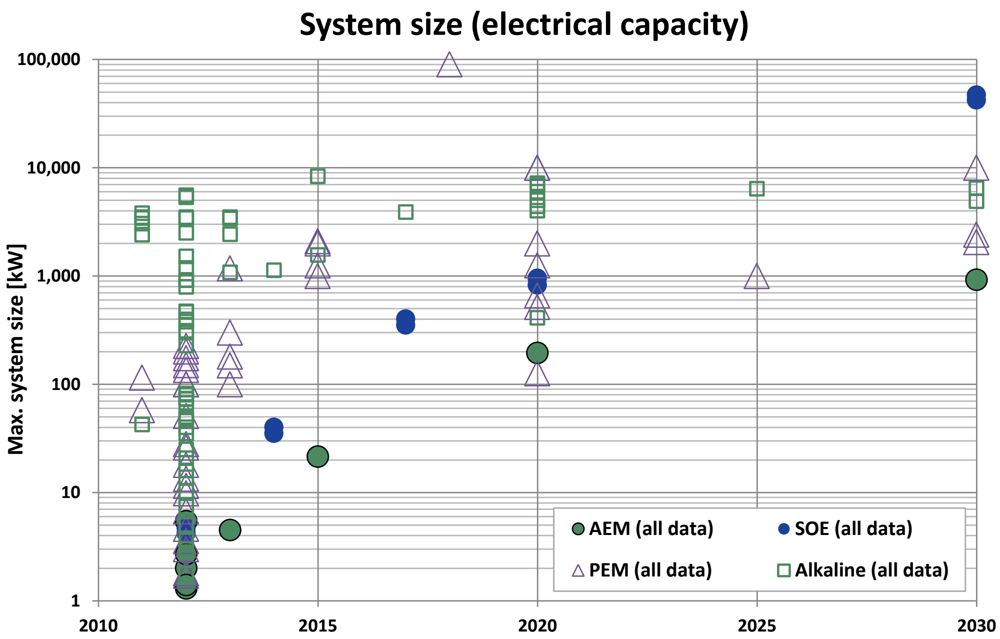
KPI data and trend lines

This appendix section provides detailed data on key performance indicators (KPIs) collected during Task 1 and the central case trend lines as well as ranges set in this project. It is worth noting that due to the small number of actors working on AEM and SOE, fewer data are available on these technologies than on alkaline and PEM.

System and stack size

System and stack size data are provided in electrical load at nominal capacity, as this unit is seen as more approachable in view of integration into the electricity grid. For data sources that only provide an output in hydrogen production per unit of time (typically Nm^3/hr), the hydrogen production rate was converted into electrical load using the nominal electrical input (typically given in kWh/Nm^3 or kWh/kg).

The collected data on system size show that alkaline electrolysers are currently the only technology available at beyond one MW system size. However, between 2015 and 2020 PEM systems are expected to catch up. Data points on more novel technologies like AEM and SOE are rare. AEM is currently only available at sub 10 kW sizes and the outlook on the scale-up of system size relies on the views of a very limited number of actors active in this technology. SOE has been demonstrated at lab scale in the form of short stacks[23], and views on system scale development are scarce, given the large uncertainty due to the early stage of technology development. Should SOE technology mature, system sizes comparable to or bigger than today's alkaline systems are forecast in the long term.



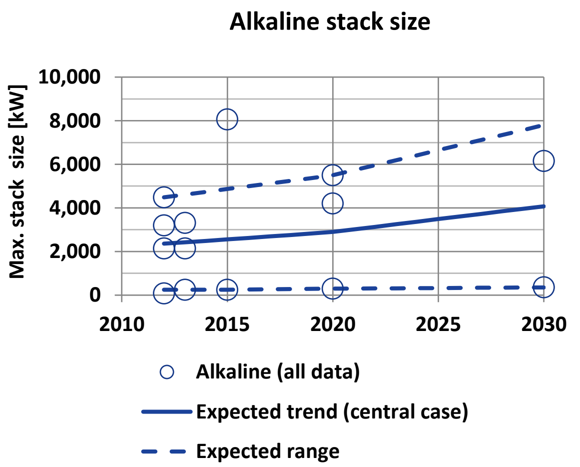
[23] A stack consisting of a few cells only (typically 5 to 50 stacked cells). Short stacks are often used for testing and demonstration at lab scale.

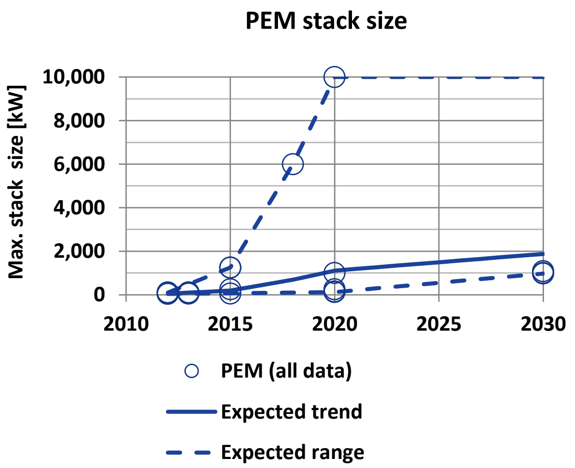
An expected typical range of maximal system sizes offered by manufacturers of alkaline and PEM electrolysers has been developed in consultation with stakeholders. In the Central case, it is expected that commercial PEM systems around 2020 will be comparable to alkaline systems in terms of size. The difference in the range of system sizes from 2020 onwards for the two chemistries is due to a single manufacturer with a targeted system size close to 100 MW in PEM technology.

System size			Today	2015	2020	2025	2030
kW	Alkaline	Central	**3,200**	**3,600**	**5,500**	**6,100**	**6,700**
		Range (1)	1,100 - 5,300	1,600 - 5,600	5,000 - 6,000	5,000 - 7,300	4,900 - 8,600
	PEM	Central	**180**	**2,100**	**5,400**	**5,900**	**6,400**
		Range (1)	100 - 1,200	1,300 - 10,000	1,600 - 90,000	1,800 - 90,000	2,100 - 90,000

(1) range indicates the largest systems offered for use in energy related applications. Smaller systems do exist.

The largest PEM systems available today consist of several stacks, and some alkaline manufacturers also combine several smaller stacks into their systems rather than designing single (multi-MW) stacks. Stack size is another indicator that characterises the status of scale development, since the strategies to achieve large system size differ among manufacturers. The data set on stack sizes is considerably smaller than that for system size, simply because stack size data are often not made public by the manufacturers.





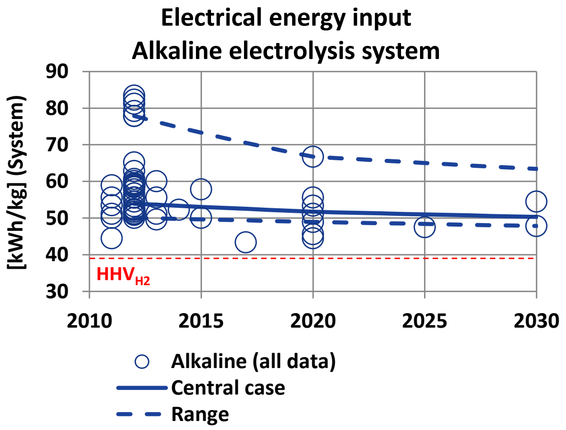
Stack size			Today	2015	2020	2025	2030
kW	Alkaline	Central	**2,400**	**2,600**	**2,900**	**3,500**	**4,100**
		Range (1)	200 - 4,500	200 - 4,900	300 - 5,500	300 - 6,700	400 - 7,800
	PEM	Central	**50**	**200**	**1,100**	**1,500**	**1,900**
		Range (1)	40 - 100	100 - 1,300	100 - 10,000	500 - 10,000	1,000 - 10,000

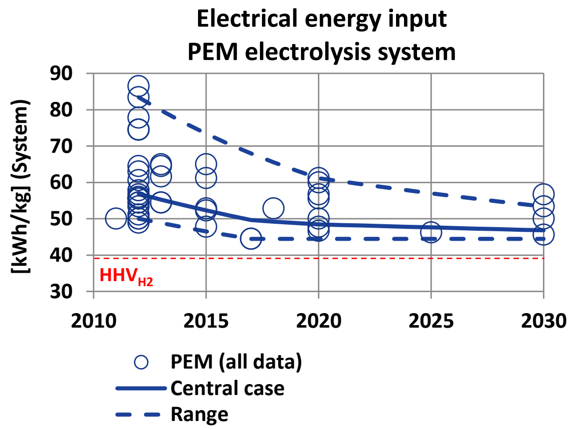
(1) range indicates the largest stacks offered for use in energy related applications. Smaller stacks do exist.

Electrical energy input and electric efficiency (LHV)

Data on electrical energy input in kWh/kg_{H2} and related electrical efficiency based on the lower heating value (LHV) of hydrogen has been collected from literature, technical data sheets and communication with manufacturers. These values refer to a system boundary that includes losses for AC-DC conversion, other typical balance of plant, gas purification and drying to achieve at least 99.4%

purity. Most of the efficiency data refer to hydrogen output at higher purities[24]. Data are not differentiated by hydrogen output pressures, and efficiency penalties due to optional external compression are not included.





Electricity input (1)			Today	2015	2020	2025	2030
kWh_{el}/kg_{H2}	Alkaline	Central	**54**	**53**	**52**	**51**	**50**
		Range (2)	50 - 78	50 - 73	49 - 67	48 - 65	48 - 63
	PEM	Central	**57**	**52**	**48**	**48**	**47**
		Range (2)	50 - 83	47 - 73	44 - 61	44 - 57	44 - 53

(1) at system level, incl. power supply, system control, gas drying (purity at least 99.4%). Excl. external compression, external purification and hydrogen storage

(2) some outliers excluded from range

LHV efficiency (electrical) (1)			Today	2015	2020	2025	2030
% (LHV, el)	Alkaline	Central	**62%**	**63%**	**64%**	**65%**	**66%**
		Range (2)	43% - 67%	45% - 67%	50% - 68%	51% - 69%	53% - 70%
	PEM	Central	**59%**	**63%**	**68%**	**69%**	**71%**
		Range (2)	40% - 67%	45% - 71%	54% - 74%	58% - 74%	62% - 74%

(1) at system level, incl. power supply, system control, gas drying (purity at least 99.4%). Excl. external compression, external purification and hydrogen storage.

(2) some outliers excluded from range

Data on AEM suggest substantial advancements in recent years with LHV efficiency climbing from 55% to 66% (60 kWh/kg_{H2} to 50 kWh/kg_{H2}). However, this has only been demonstrated for small systems (1 Nm^3/hr).

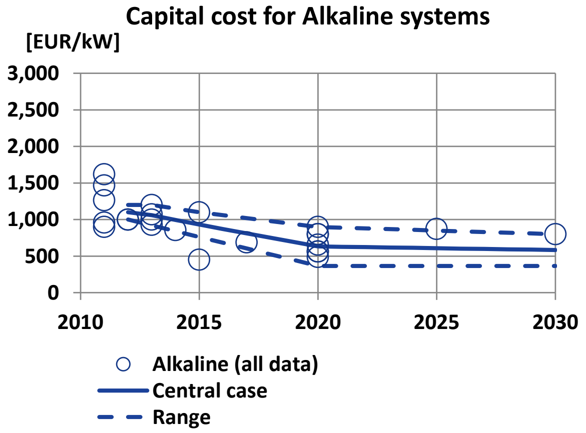
Dependable efficiency data for SOE systems is not available. A major driver for development of SOE is its potential to supply part of the required energy input in the form of heat which could come from a low cost, non-electric source or even from waste heat from an industrial process. Through this the electric energy input can be reduced considerably[25]. A roadmap for SOE development (planSOEC, 2011) and an electrolyser review (Van Mathiesen et al., 2013) suggest long term electrical system

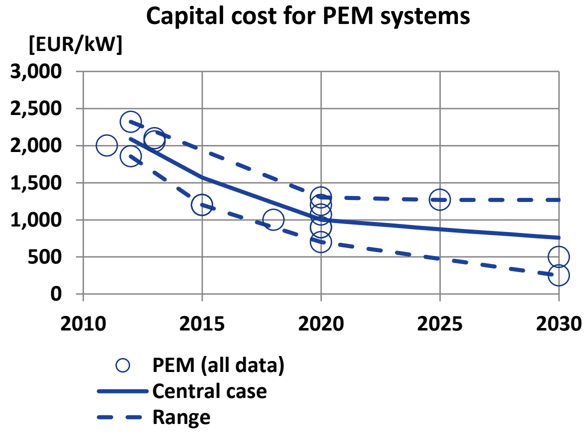
[24] Up to 99.9998%, water vapour <2 ppm, atmospheric dewpoint -72°C

[25] High temperature PEM (incorporating membranes suited for elevated temperatures) is being tried at elevated temperatures between 100°C and 200°C as well, while SOE would operate at about 800°C

efficiency of 75-79% based on LHV (44.5 kWh/kg$_{H2}$ – 42.5 kWh/kg$_{H2}$), if water at ambient temperature is fed into the system. If the system is fed with steam at 125°C temperature, the electrical system efficiency could reach 85-90% based on LHV (39 kWh/kg$_{H2}$ – 36.5 kWh/kg$_{H2}$). Actors in SOE also emphasise the potential for co-electrolysis of both steam and CO_2, producing syngas, from which hydrocarbons such as liquid fuels can be synthesised. The scope of this study did not include routes towards hydrocarbons that employ electrolysis. However, this route may have advantages over an electrolysis plus methanation process, should a hydrocarbon be desired as the final fuel.

System cost





System cost [(1)]			Today	2015	2020	2025	2030
EUR/kW	Alkaline	Central	**1,100**	**930**	**630**	**610**	**580**
		Range	1,000 - 1,200	760 - 1,100	370 - 900	370 - 850	370 - 800
	PEM	Central	**2,090**	**1,570**	**1,000**	**870**	**760**
		Range	1,860 - 2,320	1,200 - 1,940	700 - 1,300	480 - 1,270	250 - 1,270

[(1)] incl. power supply, system control, gas drying (purity above 99.4%). Excl. grid connection, external compression, external purification and hydrogen storage

SOE systems are currently not available, so dependable data on cost do not exist. Literature suggests a cost at market introduction of about 2,000 €/kW. Long term cost estimates for fully mature SOE technology are rather uncertain and vary widely from close to 300 €/kW to slightly above 1,000 €/kW.

Operational cost

Operational costs (opex) exclusive of electricity and stack replacement found in literature are typically 3-4% of the initial capital expenditure (capex) per year, with little difference among different chemistries. Manufacturers emphasize the fact that this number is very sensitive to location (labour cost) and size. We therefore used an approach that relates consumables, i.e. material cost for planned and unplanned maintenance, to the capex (1.5% of initial capex per year)[26]. On top of the consumables, we add an estimated labour cost in central Europe for regular checks by the operator

[26] NB this excludes the cost of stack replacements at the scheduled end of a stack lifetime, which are included separately in the model.

as well as planned and unplanned maintenance works, which all depend on system scale. For the different systems modelled in the TEA the estimated operational cost as a percentage of initial capex is given below.

Plant size [MW]	Opex [% of initial capex per year]
1	5.00%
5	2.20%
10	2.20%
20	1.85%
50	1.64%
100	1.61%
250	1.54%
1,000	1.52%

Translated into annual costs, the operational cost decreases slightly from now till 2030, as material costs related to initial capex also reduce, as described above.

Operational cost (excl. electricity)				Today	2030
EUR/kW/ year	Alkaline	Central	System size dependent ranges	**17-51**	**9-44**
		Range		15-53	6-47
	PEM	Central		**32-66**	**12-46**
		Range		28-70	4-54

Availability

The availability of electrolyser systems in hours per year is reduced by scheduled maintenance and unscheduled interruptions. Only very few manufacturers agreed to provide data here, as availability is naturally dependent on where a system is installed, which applications it serves (high availability may or may not be a crucial factor in a given application), and how it is operated (continuous or dynamically) and serviced. Data on availability can therefore not be generalised. However, the data points received suggest that both alkaline and PEM can achieve above 95% availability.

The limited data provided below is intended to be indicative only. Minor differences between PEM and alkaline today should not be taken to suggest that one technology has an advantage. Rather, these minor differences derive from the different applications in which the two chemistries are typically operated.

Availability			Today	2015	2020	2025	2030
hours/year	Alkaline	Central	**8,585**	**8,585**	**8,585**	**8,585**	**8,585**
		Range (1)	8,585 - 8,585	8,585 - 8,585	8,585 - 8,585	8,585 - 8,585	8,585 - 8,585
	PEM	Central	**8,443**	**8,459**	**8,586**	**8,586**	**8,586**
		Range (2)	8,585 - 8,300	8,618 - 8,300	8,672 - 8,500	8,672 - 8,500	8,672 - 8,500

(1) Only one alkaline manufacturer provided availability data

(2) Only two PEM manufacturer provided availability data

Lifetime of stack and system under continuous operation

Stacks rarely fail catastrophically, therefore stack lifetime is expressed as an 'acceptable' efficiency degradation over time. The 'acceptable' efficiency reduction strongly depends on the importance of electricity cost in a given application. Efficiency degradation is typically given as a voltage increase (µV/hour), and is often not included in technical data sheets of commercial products.

A linear voltage degradation of 1µV/hr translates into an additional electrical energy input of ~2 kWh/kg$_{H2}$ after 60,000 hours of continuous operation. Literature data and data received from manufacturers suggest degradation under continuous operation covers a wide range of 0.4–15 µV/hr.

Data on the lifetime of stacks provided by manufacturers include an efficiency drop accepted by the customers they are selling to, and is also driven by the lifetime of the most vulnerable parts such as the membrane.

Stack lifetime (1)			Today	2015	2020	2025	2030
hours	Alkaline	Central	**75,000**	**80,000**	**95,000**	**95,000**	**95,000**
		Range	60,000 - 90,000	70,000 - 90,000	90,000 - 100,000	90,000 - 100,000	90,000 - 100,000
	PEM	Central	**62,000**	**67,000**	**74,000**	**76,000**	**78,000**
		Range	20,000 - 90,000	30,000 - 90,000	50,000 - 90,000	55,000 - 90,000	60,000 - 90,000

(1) Available data is representative of continuous operation. Stack lifetime under dynamic operation may vary.

Data on system lifetime includes a certain number of stack swaps. Data on system life for commercial alkaline and PEM systems exceeds the lifetime of projects modelled in the TEA. Therefore, this value has no impact on the outcome of the TEA.

System lifetime (1)			Today	2015	2020	2025	2030
years	Alkaline	Central	**25**	**26**	**28**	**29**	**30**
		Range (2)	20 - 30	22 - 30	25 - 30	28 - 30	30 - 30
	PEM	Central	**20**	**22**	**25**	**28**	**30**
		Range	10 - 30	14 - 30	20 - 30	25 - 30	30 - 30

(1) Typically includes several stack replacements or overhauls under continuous operation.

(2) Range excl. outlier with 50 years lifetime

Dynamic operation

Within this study, the ability of an electrolyser system to operate dynamically has been captured by the following metrics, for which data tables are provided below:

- Minimum part load operation (also referred to as minimum turn-down ratio)
- Start-up time from ambient temperature
- Ramping up and down between minimum part load and full load

Minimum part load operation			Today	2015	2020	2025	2030
$\%_{(\text{full load})}$	Alkaline	Central	**30%**	**24%**	**15%**	**15%**	**15%**
		Range	20% - 40%	16% - 33%	10% - 20%	10% - 20%	10% - 20%
	PEM	Central	**9%**	**7%**	**4%**	**4%**	**4%**
		Range	5% - 10%	3% - 8%	0% - 5%	0% - 5%	0% - 5%

Startup time - from cold[(1)] to minimum part load (Hydrogen production)			Today	2015	2020	2025	2030
minutes	Alkaline [(2)]	Central	**20**	**20**	**20**	**20**	**20**
		Range	20min - several hours	20min - several hours	20min - several hours	20min - several hours	20min - several hours
	PEM [(3)]	Central	**5**	**5**	**5**	**5**	**5**
		Range	5 - 15	5 - 15	5 - 15	5 - 15	5 - 15

[(1)] pressurised if applicable

[(2)] Start-up times depend on system design (pressurised/unpressurised) and system optimisation. Start-up time in terms of electrical load typically quicker, while efficiecny during start-up phase reduced.

[(3)] Start-up times from power conservation mode can be <1min

Ramp up from minimum part load point to full load			Today	2015	2020	2025	2030
$\%_{(\text{full load})}$ /second	Alkaline	Central	**7%**	**13%**	**17%**	**17%**	**17%**
		Range [(1)]	0.13% - 10%	0.13% - 20%	0.13% - 25%	0.13% - 25%	0.13% - 25%
	PEM	Central	**40%**	**40%**	**40%**	**40%**	**40%**
		Range [(2)]	10% - 100%	10% - 100%	10% - 100%	10% - 100%	10% - 100%

[(1)] Based on data from three alkaline manufacturers

[(2)] Based on data from three PEM manufacturers

Ramp down from full load point to minimum part load			Today	2015	2020	2025	2030
$\%_{(\text{full load})}$ /second	Alkaline	Central	**10%**	**20%**	**25%**	**25%**	**25%**
		Range [(1)]	10% - 10%	20% - 20%	25% - 25%	25% - 25%	25% - 25%
	PEM	Central	**40%**	**40%**	**40%**	**40%**	**40%**
		Range [(2)]	10% - 100%	10% - 100%	10% - 100%	10% - 100%	10% - 100%

[(1)] Based on data from two alkaline manufacturers

[(2)] Based on data from three PEM manufacturers

In addition to these metrics, the ability to overload a *stack* at times to take up peaks of e.g., fluctuating renewable power is another metric that some manufacturers mention. However, this is complicated by the fact that peripheral components such as pumps and also the AC-DC converter and the grid connection would need to be sized for the maximum overload point. Therefore, at the *system* level, it is clearer to define the system nominal load as the maximum load possible, regardless of whether this is considered an overload condition or not.

Efficiency at different loads is connected with overload ability. At a cell level, the main driver of efficiency is the current density. High currents require higher overpotentials, reducing the efficiency.

At *cell and stack level*, best efficiency is therefore achieved at low loads. Whether or not this efficiency advantage at low loads is realised at the *system level* depends on whether the peripheral components within the system have been designed for part load operating conditions.

Since industrial electrolysis applications did not typically require operation at part load, many manufacturers have not yet optimised their systems for this need, and data on system level part load efficiency is very limited. A few data points suggest that best efficiencies at system level would be achieved between 40% and 60% of nominal load, but this is heavily dependent on system optimisation strategies. These few data points also suggest that for current technology, an efficiency advantage of about 10 percentage points could be achieved at 50% part load versus full load.

Current densities

Data on current densities at nominal load operation of electrolyser is shown below. The expectation for both alkaline and PEM, is that current densities can be increased substantially in the future, which is one of the main approaches to lower specific system cost.

Current density			Today	2015	2020	2025	2030
A/cm²	Alkaline	Central	**0.3**	**0.4**	**0.7**	**0.7**	**0.8**
		Range	0.2 - 0.4	0.2 - 0.7	0.3 - 1.0	0.5 - 1.0	0.6 - 1.0
	PEM	Central	**1.7**	**1.9**	**2.2**	**2.4**	**2.5**
		Range	1.0 - 2.0	1.2 - 2.2	1.6 - 2.5	1.6 - 2.8	1.6 - 3.0

AEM technology currently achieves about 0.5 A/cm² under continuous operation, with a long term potential seen at about 1.5 A/cm². Lab scale SOE currently achieves between 0.75 and 1 A/cm² and may reach 2 A/cm² once the technology is mature.

Hydrogen output pressure

Pressurised electrolysis is often discussed as one way to reduce the overall cost and potentially increase reliability of an electrolyser plant. Different strategies to pressurised operation exist. At the cell level, thermodynamically pressurising requires slightly more energy (a higher overpotential) than unpressurised electrolysis, but this can be balanced against fewer, smaller or simpler external compression stages which often add complexity and unreliability. In practice, some manufacturers report that they do not observe an efficiency penalty at pressures around 30 bars compared to operating the system unpressurised. Reduced bubble size (hence higher effective active electrode area) at elevated pressures is considered as one reason for this observation. Broadly, electrochemical compression of hydrogen within the stack is principally more energy efficient than external mechanical compression (provided oxygen is not pressurised in the stack), but system benefits are more complex to ascertain.

Pressurised operation is therefore linked to manufacturers' design choice and system philosophy. The trend is currently towards hydrogen output at greater than atmospheric pressure (30-80 bar), thus eliminating the first stage of external compression. In certain use cases (e.g., feeding into distribution gas grids) an electrolyser operating pressure of about 60 bar could completely eliminate the need for external compression. If a market for such applications arises, 60 bar systems may become available. Industrial applications often do not require pressurised hydrogen.

Hydrogen output pressure			Today	2015	2020	2025	2030
bar(g)	Alkaline	Central	**15**	**20**	**30**	**30**	**30**
		Range (1)	0.05 - 30	0.05 - 40	0.05 - 60	0.05 - 60	0.05 - 60
	PEM	Central	**20**	**30**	**30**	**30**	**30**
		Range (1)	10 - 30	20 - 80	30 - 100	30 - 100	30 - 100

(1) some outliers are excluded from the range (pressures up to 450 bar have been reported for a tubular design)

AEM systems available today operate up to 30 bar, while 50 bar operation has been tested in labs. SOE short stacks[27] are currently not pressurised and future pressure levels are uncertain.

Operating temperature

The required cell potential to split water reduces with increased temperature. This does not reduce the minimum *total* energy requirement (39.4 kWh/kg_{H2}) for production of hydrogen from liquid water, but reduces the required minimum *electrical* energy input to split water by increasing the *thermal* energy input.

Operating at elevated temperatures is therefore one strategy to improve overall electrical efficiency. Alkaline and PEM electrolysers available today operate between 50°C and 80°C. AEM systems currently operate at 50°C, but operation at higher temperatures is also being explored.

Operating temperature			Today	2015	2020	2025	2030
°C	Alkaline	Central	**70**	**70**	**70**	**73**	**75**
		Range (1)	60 - 80	60 - 80	60 - 80	60 - 85	60 - 90
	PEM	Central	**60**	**64**	**70**	**70**	**70**
		Range (2)	50 - 80	54 - 84	60 - 90	60 - 90	60 - 90

(1) excludes outliers of up to 150°C (pressurised)

(2) excludes outliers of up to 200°C (pressurised)

[27] A stack consisting of a few cells only (typically 5 to 50 stacked cells). Short stacks are often used for testing and demonstration at lab scale.

Appendix 5

Detailed techno-economic analysis

Further detail on the techno-economic analysis is provided in the following slides.

Final report: Task 2
Techno-economic modelling of electrolyser systems

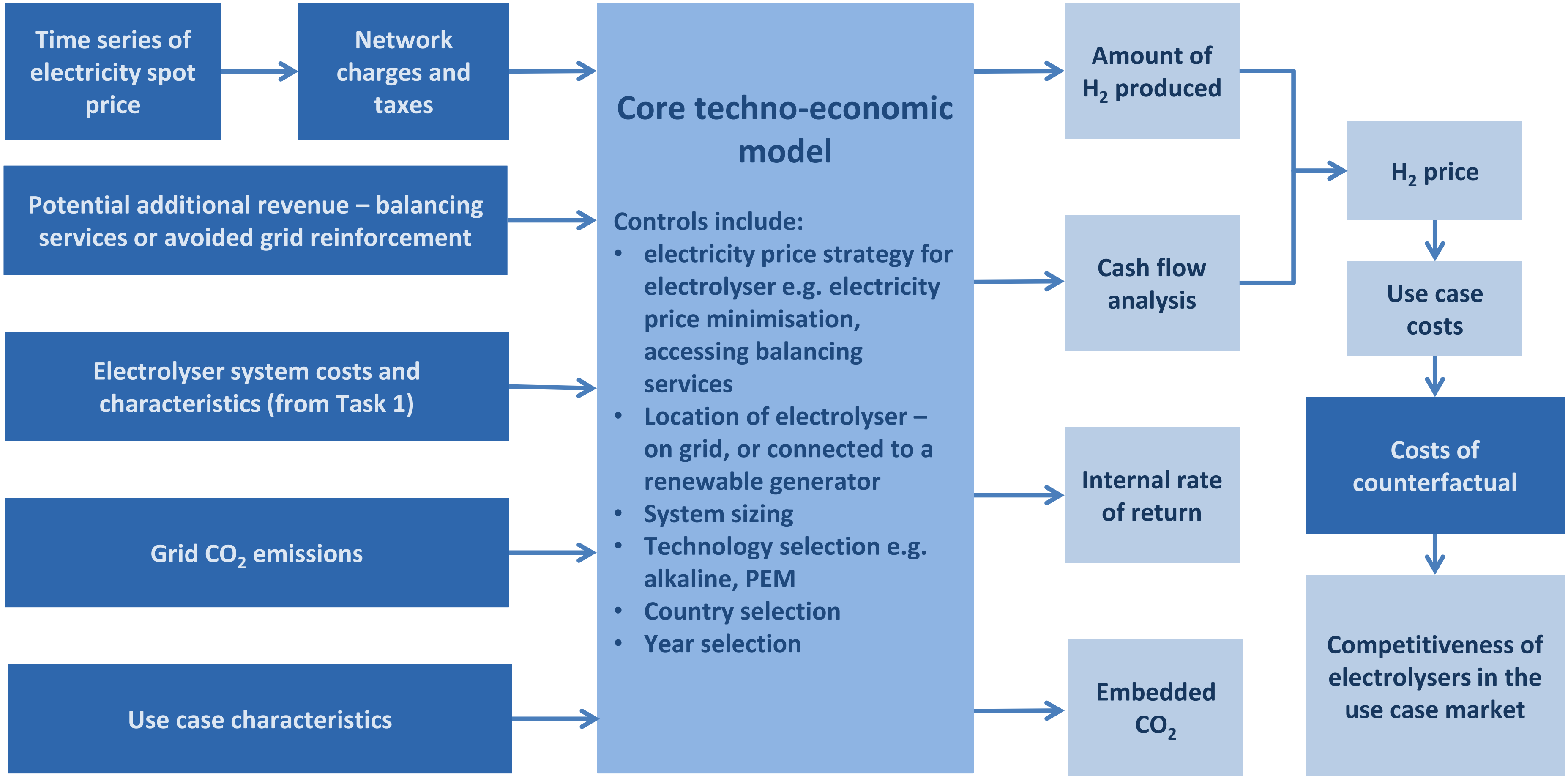
FCH JU

7/2/2014

Ben Madden
Eleanor Standen
Alvin Chan
Element Energy Limited

- Introduction to the techno economic model and data
- Results of the techno-economic modelling
- Target setting: sensitivity of the hydrogen price to the key parameters
- Conclusions
- Appendices
    - Energy markets and data
    - Electrolyser operating modes

A techno-economic model of the electrolyser system has been constructed

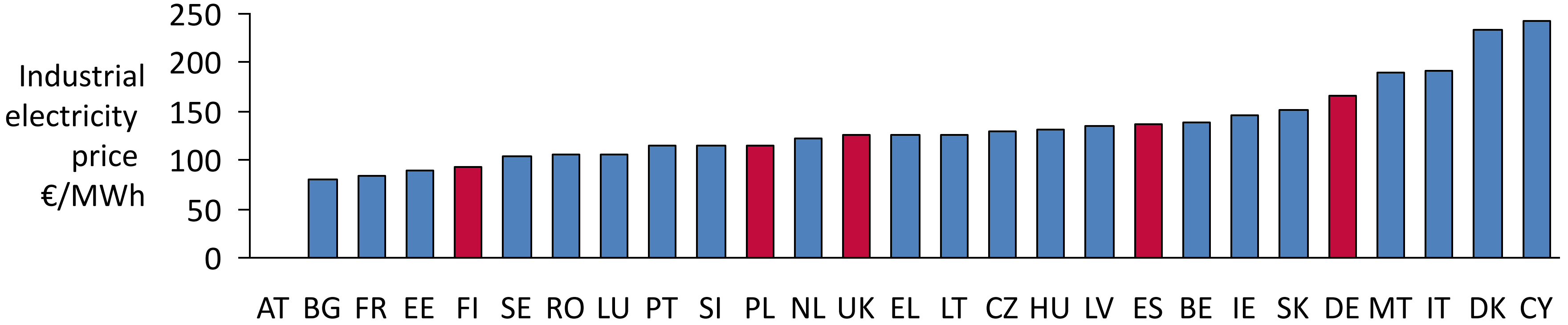


The model is fed by the input data from Task 1, along with a number of other data sources and assumptions, which are detailed in the appendix

Five countries are selected for analysis: Germany, Spain, the UK, Poland and Finland

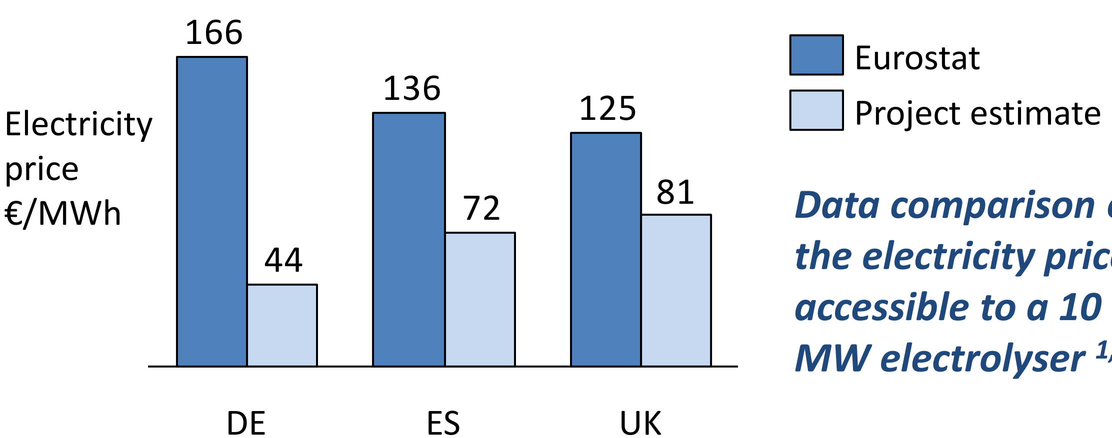
There were 3 aims to the country selection:

1/ To select countries which spanned the range of industrial electricity prices[1]:



Comparison of industrial electricity prices across the EU in 2011 [1]. Countries selected for further analysis are highlighted in red.

However, based on detailed analysis of three of the selected countries, the electricity price which electrolysers can access can be lower than the industrial prices quoted by Eurostat:

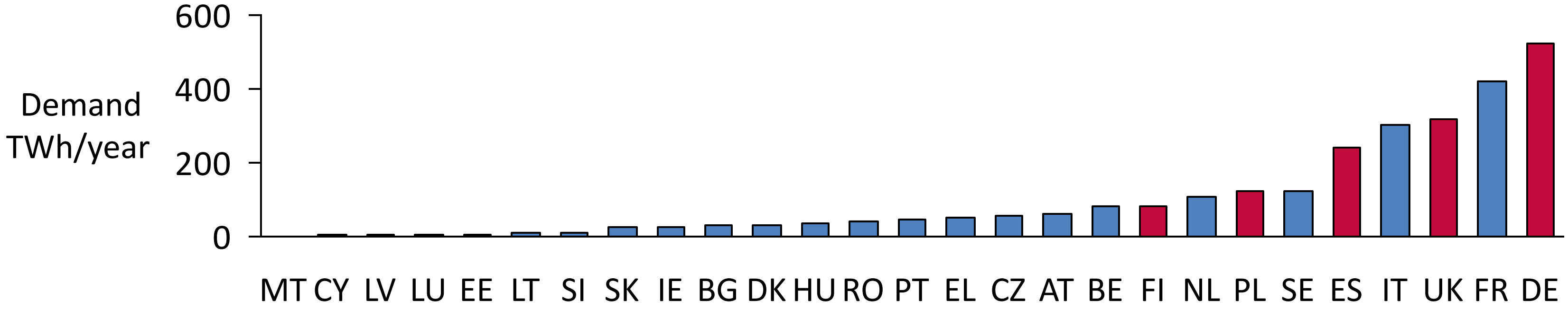


Data comparison of the electricity price accessible to a 10 MW electrolyser [1, 2]

1 – Source: Eurostat, Band IC : 500 MWh < Consumption < 2 000 MWh. Data is not available for all Member States for higher consumption bands. 2 – Project estimates based on country specific data sources see appendix.

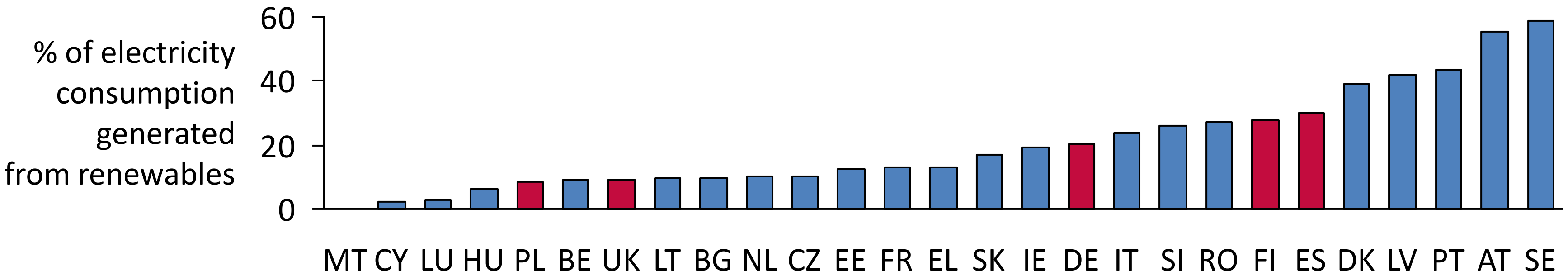
Five countries are selected for analysis: Germany, Spain, the UK, Poland and Finland

2/ To select countries which would be representative of the EU market as a whole, by covering a large proportion of the EU market. The countries selected were those with larger and medium sized markets so that the analysis covered nearly 50% of the EU market



Graph to show the electrical demand in EU Member States in 2011. Countries selected for further analysis are highlighted in red[1]

3/ To select countries which represent differing proportions of renewable energy generation



Graph to show the percentage of electricity consumed which is generated from renewable resources in 2011. Countries selected for further analysis are highlighted in red[2]

Three use cases are specified for the end use of the hydrogen:

Use case 1: Transport

1a: Small car HRS
- 1 MW onsite 400 kg/day
- 700 bar refuelling
- 1 day's storage

1b: Large car HRS
- 5 MW onsite
- 2000 kg/day
- 700 bar refuelling
- 1 day's storage

1c: large bus depot
- 10 MW onsite
- 4000 kg/day
- 350 bar refuelling
- 1 day's storage

1d: distribution from central electrolyser
- 20 MW
- tube trailer deliveries
- Serves 20 x 400kg/day car HRS

Use case 2: Industrial hydrogen

2a
- 10 MW electrolyser
- 1 day's storage plus pipeline

2b
- 100 MW electrolyser
- 1 day's storage plus pipeline

2c
- 250 MW electrolyser
- 1 day's storage plus pipeline

Use case 3: Energy storage

3a: Re-electrification
- 100 MW electrolyser
- Geological storage
- Hydrogen turbines
- H2 produced at low elec prices, and burnt at high elec prices

3b: Domestic heating
- 10 MW electrolyser
- Injected into gas grid via a network entry plant
- Storage in the high pressure gas grid

3c: Transport
- 1 GW electrolyser
- Geological storage
- Distributed to HRS as per use case 1 x

Three categories of system size, and end use for the hydrogen, are considered to explore the markets which water electrolysers could serve

The use case is needed to determine the steps, and associated costs required to take the hydrogen out of the electrolyser system, and deliver it to the end user. Three broad categories are explored, which vary by both the size of the electrolyser systems, and the end use for the hydrogen. The three use cases are as follows:

1. **Small systems for transport applications.** This use case explores the steps and associated costs required to use electrolytic hydrogen in hydrogen refuelling stations (HRS) for fuel cell vehicles and buses. A range of system sizes is explored, serving car HRS or bus depots. The relative merits of on-site electrolysis compared to delivery from a large centralised electrolyser is also explored.

2. **Medium systems for industrial applications.** This use case explores the steps and associated costs required to use electrolytic hydrogen in industrial applications, such as ammonia production. A range of system sizes is explored, and it is assumed that an electrolyser produces hydrogen for an industrial park, and the hydrogen is transported to individual sites by pipeline.

3. **Large systems for energy storage applications.** This use case explores the steps and associated costs required to use electrolytic hydrogen as an energy storage medium, by considering large scale systems which could take advantage of excess renewables or other cheap electricity. The end uses considered are re-electrification, or for use as heating by injection into the gas grid, or for use as a transport fuel.

Use case scenarios and assumptions
1. Small use case – transport applications

Use case	Sizing	Compression requirement	Storage	Other requirements	Data sources
Small use case <25 MW System is sized by demand as per the assumptions below. The electrolyser systems are sized according to demand, with limited redundancy included in case of failure of one or more of the electrolyser units. Storage provides 24 hours worth of hydrogen in case of short periods of down-time. In the case of longer periods of downtime, hydrogen would be delivered from an alternative source. MW equivalents are given on the basis of efficiencies of 60 kWh/kg					
1a **Small Car HRS**	100 cars @ 4 kg 400 kg/day 1 MW	700 bar	1 day's worth	Dispenser costs and HRS additional engineering costs	US H2A, plus Element Energy aggregated deployment project dataset
1b **Large Car HRS**	500 cars @ 4 kg 2000 kg/day 5 MW	700 bar		Dispenser costs and HRS additional engineering costs	
1c **Large bus depot**	200 buses @ 20 kg 4000 kg/day 10 MW	350 bar		Dispenser costs and HRS additional engineering costs	
1d **20 MW electrolyser distributes to 20 small car HRS**	20 small HRS: Each 100 cars @ 4kg/day 20 MW	700 bar		Transport (tube trailer) costs, dispenser & HRS costs	

Counterfactual: These use cases for electrolytic hydrogen are then compared to using Steam Methane Reformer (SMR) derived hydrogen, produced in a 100 tonne/day centralised facility , which is then delivered to the hydrogen refuelling station by tube trailer.

Use case scenarios and assumptions
1. Small use case – transport applications

Small use case <25 MW
The electrolyser systems are sized according to demand, with limited redundancy included in case of failure of one or more of the electrolyser units. Storage provides 24 hours worth of hydrogen in case of short periods of down-time. In the case of longer periods of downtime, hydrogen would be delivered from an alternative source.

Use Case	Pre HRS Compression and Distribution (€/kg)	HRS (€/kg)	Use Case Electricity Annual Demand (MWh)
1a Small Car HRS	-	1.59	692
1b Large Car HRS	-	1.20	3,334
1c Large bus depot	-	1.00	4,620
1d 20 MW electrolyser distributes to 20 small car HRS	0.81	1.59	13,830

Counterfactual: These use cases for electrolytic hydrogen are then compared to using Steam Methane Reformer (SMR) derived hydrogen, produced in a 100 tonne/day centralised facility , which is then delivered to the hydrogen refuelling station by tube trailer.

Use case scenarios and assumptions
2. Medium use case – Industrial use of hydrogen

Use case	Sizing	Compression requirement	Storage requirement	Other requirement	Data sources
Medium use case 10 to 250 MW System is not sized according to demand, but instead according to a range of possible electrolyser system sizes.					
2a	10 MW	170 bar for extra storage required under intermittent electrolyser operation. Pipeline pressure requires hydrogen at 75 bar.	1 day's worth in addition to storage within the pipelines	Trunk pipeline to industrial site, then distribution pipelines to individual sites within the industrial site	US H2A
2b	100 MW				
2c	250 MW				

Counterfactual: These use cases for electrolytic hydrogen are then compared to using SMR hydrogen, produced on site, and delivered to the industrial; facilities using the same pipeline configuration and costs as set out for the use cases above.

Use case scenarios and assumptions
1. Small use case – transport applications

Medium use case 10 to 250 MW System is not sized according to demand, but instead according to a range of possible electrolyser system sizes.					
Use Case	**Size**	**Pipeline Cost (€/kg)**	**Compression Cost (€/kg)**	**Storage Cost (€/kg)**	**Use Case Electricity Annual Demand (MWh)**
2a	10 MW	1.33	0.14	0.27	1,414
2b	100 MW	0.44	0.09	0.27	14,143
2c	250 MW	0.19	0.06	0.27	35,358

Counterfactual: These use cases for electrolytic hydrogen are then compared to using Steam Methane Reformer (SMR) derived hydrogen, produced in a 100 tonne/day centralised facility , which is then delivered to the hydrogen refuelling station by tube trailer.

Use case scenarios and assumptions
3. Large use case – energy storage applications

Use case	Sizing	Compression requirement	Storage requirement	Other requirement	Data sources
Large use case 10 – 1000 MW System is not sized according to demand, but instead according to a range of possible electrolyser system sizes.					
3a re-electrification 100 MW	Peak output 390 tonnes/day	200 bar	10 days' geological storage	Hydrogen turbines	US H2A Hydrogen turbine: NREL 2009, Siemens (E4Tech pers comm)
3b injection into high pressure gas grid 10 MW	Output 3.9 tonnes/day	75 bar	No storage requirement - assume that gas grid acts as store	Network injection plant	US H2A Element Energy data UK H2 TINA
3c delivery to HRS 1,000 MW	Output 39 tonnes/day	200 bar for storage, then 500 bar for tube trailer delivery	10 days' geological storage	Tube trailer delivery, then HRS costs as per use case 1d	US H2A

Counterfactuals:

3a – Considers the cost of re-electrification, which would have value if there was an energy storage market. As this market does not exist at the moment, there isn't an appropriate counterfactual. Instead, we determine the value which an energy storage market would need to place on on-demand green electricity for this use case to be competitive.

3b - This use case is compared to the cost of the incumbent, which is natural gas in the gas grid for heating. The carbon price which would be required to make hydrogen competitive with natural gas can then be determined.

3c – As for use case 1, this use case is compared to SMR produced in a 100 tonne/day centralised facility.

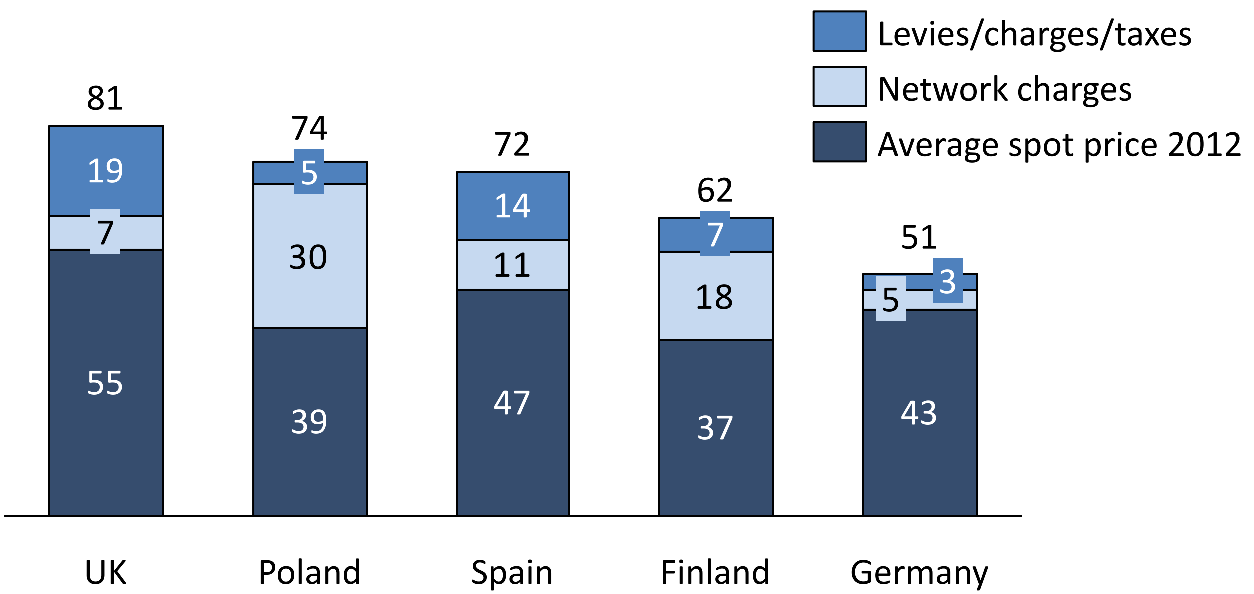
Use case scenarios and assumptions
1. Small use case – transport applications

Large use case 10 – 1000 MW System is not sized according to demand, but instead according to a range of possible electrolyser system sizes.							
Use Case	**Size**	**Pre HRS Compression and Distribution (€/kg)**	**HRS (€/kg)**	**Geological Storage and Compression (€/kg)**	**Gas injection plant and compression (€/kg)**	**Gas Turbine (€/kW)**	**Use Case Electricity Annual Demand (MWh)**
3a re-electrificatio n 100MW	100 MW	-	-	0.16	-	550	8,802
3b injection into high pressure gas grid 10 MW	10 MW	-	-	-	0.27	-	836
3c delivery to HRS 1000 MW	1,000 MW	0.81	1.59	0.09	-	-	181,558

Counterfactual: these use cases for electrolytic hydrogen are then compared to using Steam Methane Reformer (SMR) derived hydrogen, produced in a 100 tonne/day centralised facility , which is then delivered to the hydrogen refuelling station by tube trailer.

Industrial electricity prices vary between the five countries selected (2012)

Average electricity cost to industrial electrolysers, €/MWh



Cheaper electricity prices are found in countries where the regulatory regime allows exemptions from network charges and taxes in favour of electrolysers or industrial applications, e.g. Germany

Sources
Wholesale prices:
- Average spot price on the day-ahead market : UK: APX.com. Germany: EEX.com. Spain: OMIE/OMEL. Finland: ELSPOT. Poland: TGE.pl. Average gas wholesale costs: DG Energy (2013)

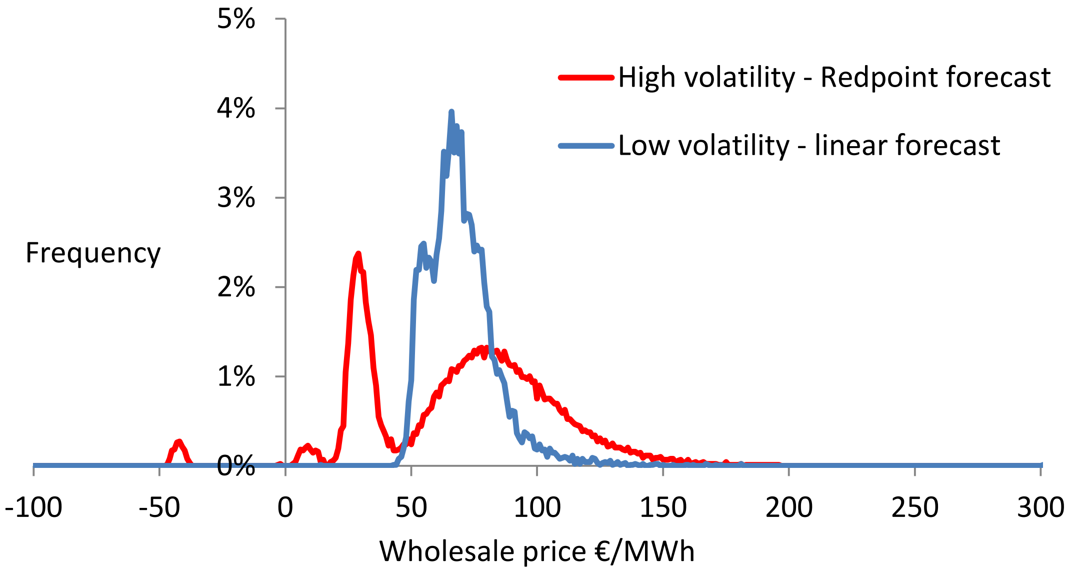
Network charges:
- UK: assumes distribution scale extra high voltage connection, 22 kV–132 kV. Germany: assumes medium voltage connection 1 kV–72.5 kV. Spain: assumes medium voltage connection 36 kV–72 kV
- Finland and Poland: as per Eurostat data for industrial consumers Band IC : 500 MWh < Consumption < 2,000 MWh

Levies, taxes and charges (VAT is not included):
- UK and Germany information taken from national legislation
- Spain, Finland and Poland as per Eurostat data for industrial consumers Band IC : 500 MWh < Consumption < 2,000 MWh

Two different models for wholesale electricity price volatility are used in the analysis

Electricity price volatility is important for strategies such as price minimisation—i.e. turning the electrolyser off when the spot price goes above a certain threshold. Two different models for volatility are used in the analysis:

- "Low volatility" – this is the volatility of today's markets. The frequency distribution curve for 2012 prices is used, and scaled to the mean price for the year in question***. This scenario is the central assumption used in the following analysis.***
- "High volatility"— assumes that an increase in renewable generation will lead to an increase in the volatility on the wholesale market. The dataset used here is the "environmentally favourable conditions" scenario from a 2009 study on the UK by Redpoint[1].



Graph to show two scenarios for the volatility of UK electricity prices in 2030. The linear forecast takes the 2012 electricity spot price frequency distribution and modifies it to be consistent with the DG ENER price for 2030. The Redpoint forecast takes the "environmentally favourable conditions" frequency distribution curve (i.e. a high renewables penetration scenario) for 2030 and modifies it so that the mean is consistent with the DG ENER for 2030.

1 Decarbonising the GB power sector, Redpoint report to the UK Committee on Climate Change

A range of KPIs are adapted from Task 1 for use in the techno-economic modelling

The model uses the following input data from Task 1, for alkaline and PEM systems:

- **Capital costs:** Central and upper and lower bounds for capital costs (€/kW) are used. Note that the Task 1 results suggest no clear evidence to justify a large variation in the specific capital cost by size of the system, so the same trend line, lower and upper bounds apply to all sizes of system in the modelling.
- **Non-electricity operation costs**: comprised of material costs and labour costs. The material costs do not vary with scale, and are set as 1.5% of the capital costs. The labour costs do scale. Note that stack replacement is considered separately from these costs.
- **Electrolyser efficiency:** Central and upper and lower bounds for peak load efficiency (kWh/kg) is used. A dynamic efficiency curve is also modelled.
- **System and stack lifetime:** The system lifetime is measured in years and is independent of the hours of use of the electrolyser. In contrast, the stack lifetime is measured in hours of operation, and if the electrolyser operates beyond the lifetime of the stack, stack replacement costs are accounted for, as well as the residual value of the stack at the end of the project lifetime.
- **Minimum turn-down ratio:** This is the minimum proportion of the total rated power the electrolyser can operate at.
- **Start-up time:** This is the time taken for the electrolyser to go from being fully shut down to get to the minimum turn-down point.
- **Ramp-up and ramp-down rates:** This is the speed at which the electrolyser can respond to signals to turn up or turn down.
- **System pressure:** The use cases assume that hydrogen is produced at 20 bar. However the sensitivity to different pressures is explored (see later slides).

Summary of the electrolyser KPIs from Task 1 used in the modelling (1/2)

2012

	Alkaline Water Electrolysers, 2012			PEM Water Electrolysers, 2012		
	Lower	**Central**	**Upper**	**Lower**	**Central**	**Upper**
Capex (€/kW)	1,000	1,100	1,200	1,856	2,088	2,320
Opex (€/kW/yr) - scale dependent)	15–50	17–51	18–53	28–63	32–66	35–70
Energy input (kWh/kg)	50	54	78	50	57	83
Stack Lifetime (hours)	90,000	75,000	60,000	90,000	62,000	20,000
Minimum turn-down ratio (%)	20	30	40	5	9	10
Start-up time (minutes)	20	20	Several hours	5	10	15
Ramp-up rate (%/sec)	10	6.7	0.1	100	40.6	10
Ramp-down rate (%/sec)	10	10	10	100	40.6	10
System pressure (bar(g))	30	15	0.05	30	20	10

Summary of the electrolyser KPIs from Task 1 used in the modelling (2/2)

2030

	Alkaline Water Electrolysers, 2030			PEM Water Electrolysers, 2030		
	Lower	**Central**	**Upper**	**Lower**	**Central**	**Upper**
Capex (€/kW)	367	583	800	250	760	1270
Opex (€/kW/yr) - scale dependent)	6–41	9–44	12–47	4–39	12–46	19–54
Energy input (kWh/kg)	48	50	63	44	47	53
Stack Lifetime (hours)	100,000	95,000	90,000	90,000	78,000	60,000
Minimum turn-down ratio (%)	10	15	20	0	4	5
Start-up time (minutes)	20	20	Several hours	5	10	15
Ramp-up rate (%/sec)	25	16.8	0.1	100	40.6	10
Ramp-down rate (%/sec)	25	25	25	100	40.6	10
System pressure (bar(g))	60	30	0.05	100	30	30

Dependence of specific capex on system scale

- Although the data from certain individual manufacturers did suggest that specific capex for larger scale systems would be lower than for smaller scale systems, taken collectively, the data from all the manufacturers did not show a trend that depends on system scale
  - i.e., some of the data 'best case' capex KPI trendline is for small systems and some is for large systems
- We believe that there are a number of factors that contribute to this:
  - Very large electrolysers (say > 50 MW) are largely conceptual at this point, so cost reductions for such systems have yet to be demonstrated
  - Different manufacturers have adopted different strategies for electrolyser deployment, with some pursuing large scale systems whilst others are not
  - There is considerable uncertainty in longer term KPI forecasts
- The specific capex KPI trendlines capture the full range of data from manufacturers and the literature and, we believe, are a reasonable representation of what is feasible regardless of individual system scale
- Given the uncertainties around the effects of scale, the current modelling does not account for effects of scale on specific capex. The effect on opex is include through reductions in labour costs for larger plants.
- Because of their very wide variation by country and region, neither civil works and installation nor land-use related costs are included in the analysis. It is entirely possible that these factors could affect the electrolysis systems and counterfactuals differently.

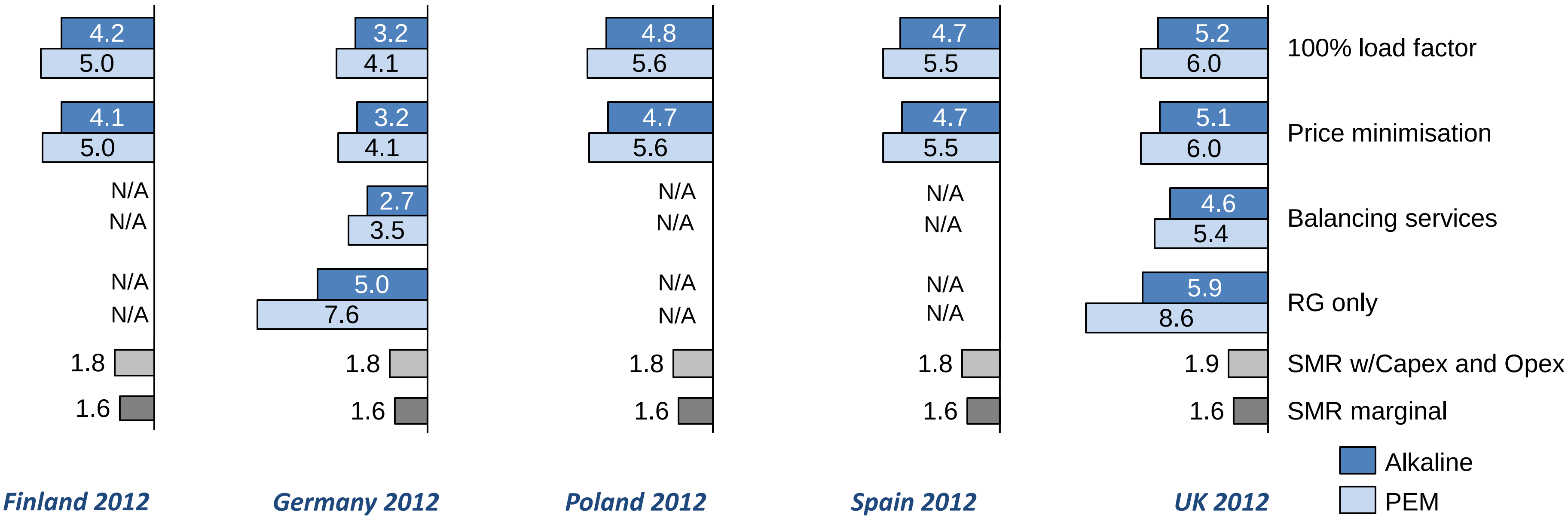
- Introduction to the techno economic model and data
- Results of the techno-economic modelling
- Target setting: sensitivity of the hydrogen price to the key parameters
- Conclusions
- Appendices
    - Energy markets and data
    - Electrolyser operating modes

Summary results for hydrogen production costs at the production site for all 5 countries (1)

2012, Best Case KPIs

Excluding end-use

Hydrogen production cost (€/kg)



Hydrogen costs (€/kg) in 2012 for best case KPIs for Alkaline and PEM electrolysers in a variety of electricity market scenarios described in the Appendix. Only UK and Germany publish load balancing data. **'RG only' refers to an off-grid scenario**, connected by private wire to a 31% capacity factor wind farm only.

Key points:

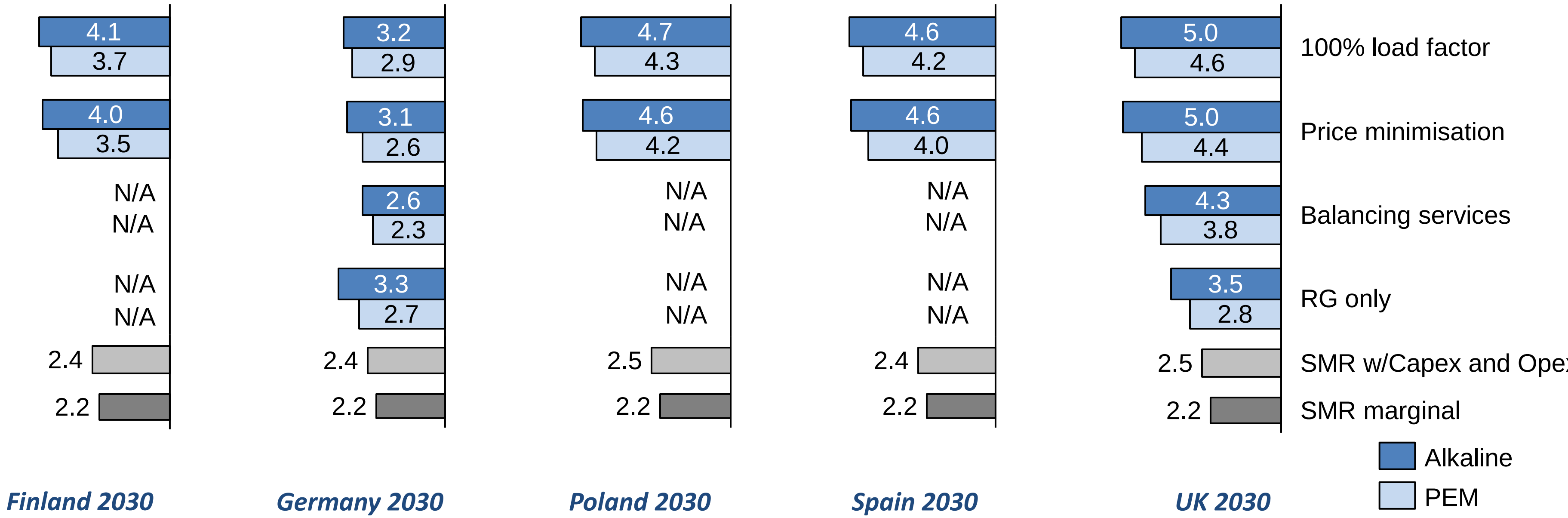
- Germany exhibits the lowest hydrogen production costs as the WE can access a combination of low wholesale electricity prices and very low electricity transmission and distribution fees
- Conversely, the UK exhibits the higher hydrogen costs due to high transmission and distribution charges
- PEM is systematically more expensive than Alkaline WEs due to the lower maturity level of the technology in 2012
- The renewable generation (RG) only scenarios include renewable subsidy (UK: ROC at € 51/MWh; Germany: EEG: at € 48/MWh as base support for 20 years plus a premium of € 88/MWh for first 5 years)

Summary results for hydrogen production costs at the production site for all 5 countries (2)

2030, Best Case KPIs

Excluding end-use

Hydrogen production cost (€/kg)



Hydrogen costs (€/kg) in 2030 for best case KPIs for Alkaline and PEM electrolysers in a variety of electricity market scenarios described in the Appendix. Electricity price volatility as per 2012. **RG only refers to an off-grid scenario**, connected by private wire to a 31% capacity factor wind farm only.

Key points:

- PEM can be more competitive than alkaline by 2030 thanks to a greater cost reduction and efficiency improvement potential over time
- Germany exhibits the lowest H_2 production costs thanks to low wholesale electricity prices and transmission/distribution fees. As a consequence, the best operating strategy for WEs is to source grid electricity and provide grid balancing services
- The situation reverses in the UK where high electricity prices and transmission/distribution fees implies that the best operating strategy for WE is to be powered by off-grid renewable generators (e.g. wind turbines)
- The RG hydrogen sharp cost reduction from the 2012 levels is driven by the WE Capex/Opex reduction and efficiency improvement. The renewable subsidy level in the UK is assumed constant at the 2012 level, whilst this is tapered in Germany (reduction: 1.5% p.a.)

Two countries are then selected as case studies for detailed analysis of the hydrogen costs with the use case costs included

Germany is selected for further analysis for the following reasons:

- Cheapest industrial electricity prices, allowing electrolysers to be close to competitive
- Electrolysers can participate in the balancing services market, allowing additional revenues to be accessed to reduce the production cost of hydrogen

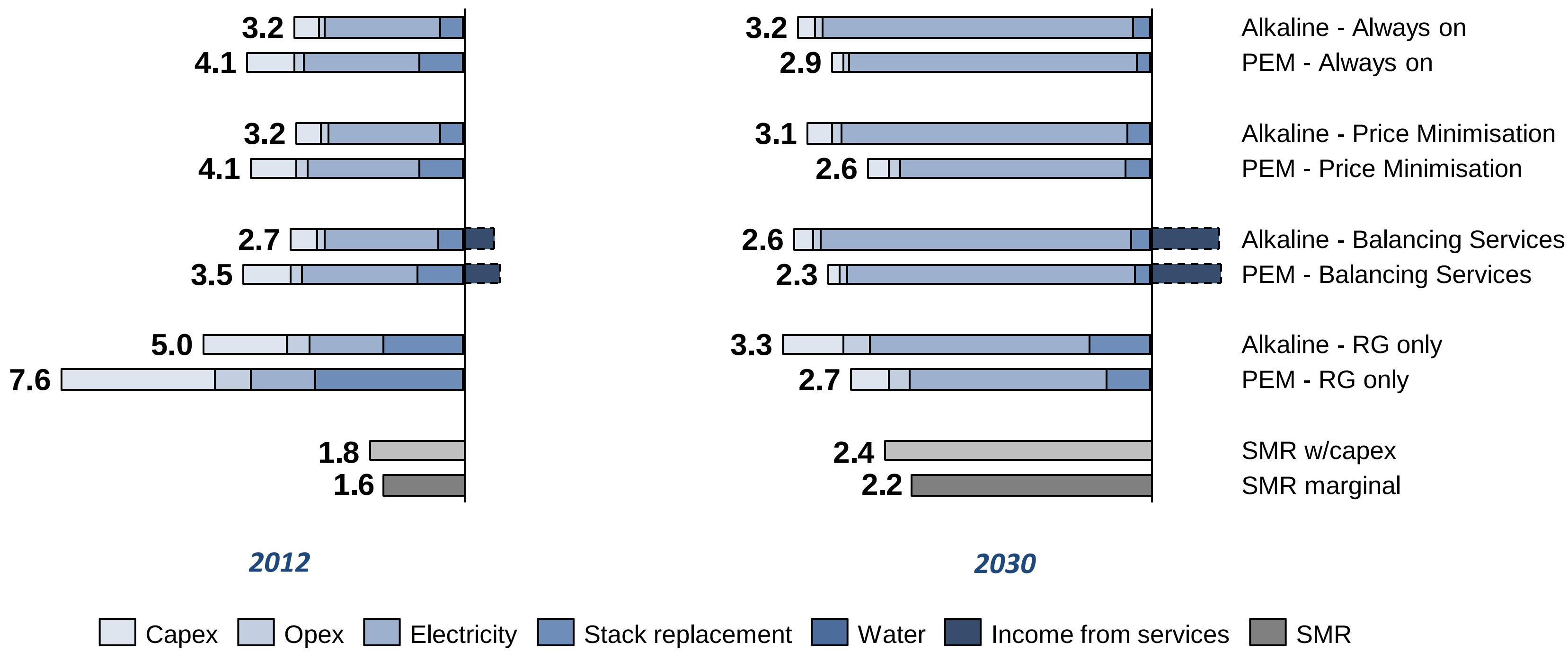
The **UK** has the highest grid electricity prices of all of the five countries. The UK is selected for further analysis in order to:

- Demonstrate that low cost electricity can be accessed in certain situations – in this example by connecting directly to a renewable generator and accessing renewable certificates.

Germany case study – electrolyser operating mode

Germany, 2012 and 2030
Best Case KPIs

Hydrogen production cost (€/kg)

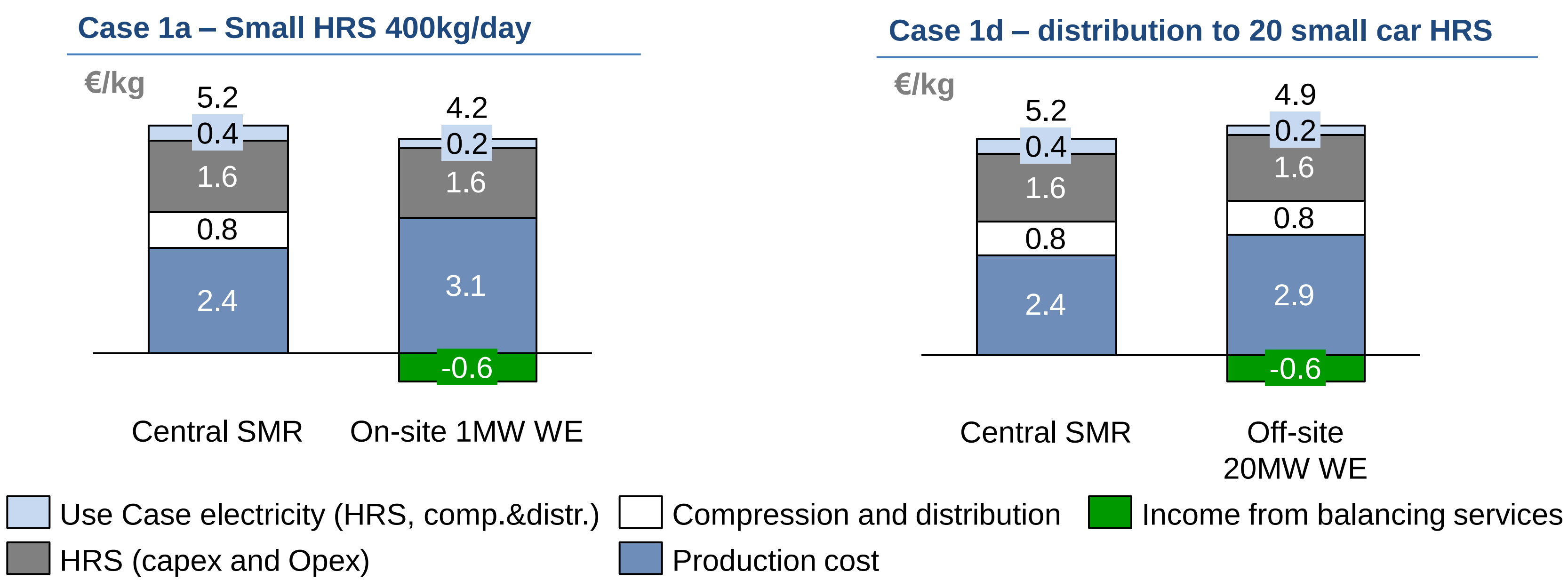


- In both 2012 and 2030 offering balancing services appears to be the best strategy for reducing costs of hydrogen production
- The following analysis of hydrogen costs in the German market therefore assumes that the electrolyser operator adopts the approach of using grid electricity and offering balancing services

In addition to the cost of hydrogen, the model adds additional downstream costs for each end use (example)

Germany, 2030

Hydrogen cost at the nozzle (**PEM** technology, CO_2 price excluded)



Comments:

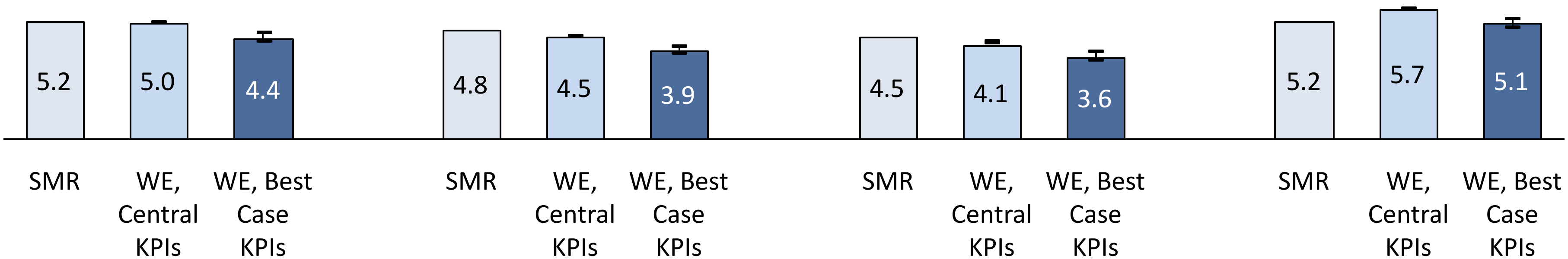
- Compressor cost and electricity requirement based on US H2A model
- Compressor electricity cost based on average price paid by electrolyser in Germany, 2030
- Storage and other HRS costs (dispenser plus additional engineering cost) based on US H2A model
- Learning rate is applied to 2012 HRS costs to get to 2030 costs
- Distribution cost: assumes tube trailer delivery – HRS located 100 km from the centralised SMR plant. Tube trailers operate within a delivery network to reduce costs.

US DOE H2A model, projected average electricity and gas price prices (DG Energy),

Use case results: 1 – small systems (≤20MW WE) providing hydrogen for transport

Germany, 2030

Hydrogen cost at the nozzle[1], €/Kg (CO$_2$ price excluded)



1a (on-site 1MW WE)
Small car HRS
400kg/day

1b (on-site 5MW WE)
Large car HRS
2000kg/day

1c (on-site 10MW WE)
Large bus depot
4000kg/day

1d (off-site 20MW WE)
8000 kg/day electrolyser distributes to 20 small HRS

All costs including compression, distribution (for SMR and cases 1d only) and HRS costs. Error bars reflect difference between PEM and Alkaline technology.

Discussion

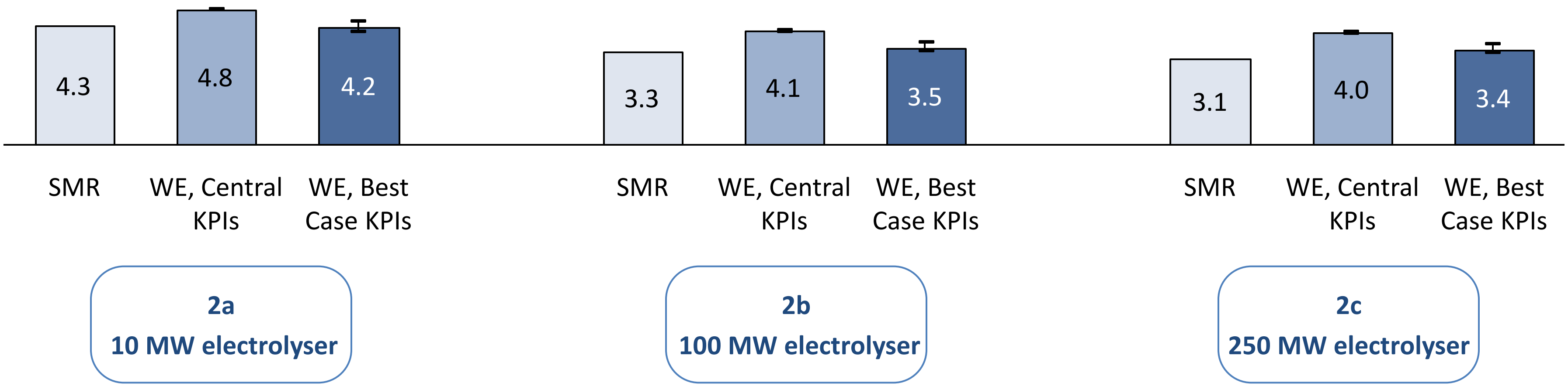
- The analysis suggests that WE technology (both on-site and offsite) can compete with SMR-derived hydrogen on all transport scenarios (1a to 1d) by 2030 in Germany
- On-site WE appears to offer a marginally cheaper solution than centralised WE plants as in the modelled scenarios 1) on-site plants of the MW scale can access to the same electricity prices and low network charges as for centralised WE plants, 2) the system Capex (€/MW installed) do not scale with size and 3) there are no distribution costs
- Results vary little with the WE technology choice. In the central KPIs case the difference between PEM and Alkaline is marginal (e.g. below 5 Euro cents per kg of hydrogen dispensed). The model returns a greater difference in the Best Case KPIs scenarios as a greater Capex difference per MW installed favours PEM (circa €0.35/kg cheaper than Alkaline technology)
- A carbon price of ~€55/tCO$_2$ would be sufficient to bridge the gap with central KPIs for all of these cases.

1 Average PEM and Alkaline values. Electricity price strategy: response services

Use case results: 2 – systems producing industrial hydrogen

Germany, 2030

Hydrogen cost[1], €/Kg (CO$_2$ price excluded)



WE are assumed to replace large on-site SMR units to produce industrial hydrogen. No HRS costs included. Scenarios include cost for a hydrogen pipeline connecting plants with the industrial end-use. Scenarios only reflects different WE sizes (from 10MW to 250MW).

Discussion

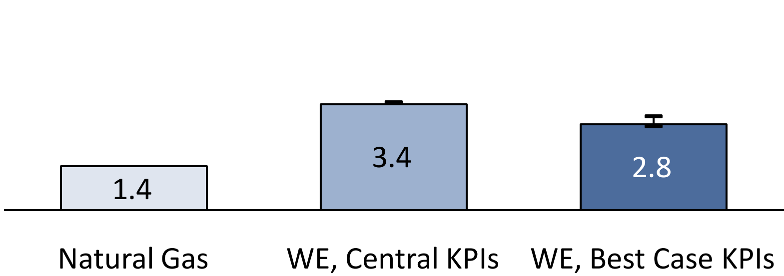
- Medium scale WE units (~100MW) struggle to compete with SMR-derived hydrogen by 2030, even if the WE technologies achieve the cost and efficiency improvements implied by the Best Case KPIs scenario
- Large scale water electrolysers (>100 MW) may have difficulty competing with SMR-derived hydrogen for large scale industrial applications.
- This is because whilst the hydrogen pipeline impact per kg$_{H2}$ decreases with the increasing dimension of the system, large WE plants have access to lower relative balancing revenues as the model only allows up to 60MW of their installed capacity to offer grid balancing services (→ threshold based on the largest capacity currently present in the balancing market[2]).
- As for the previous application case, results vary little with the WE technology choice. PEM overall performs marginally better than Alkaline solutions (circa up to €0.08/kg of hydrogen cheaper in the Central case and circa €0.35/ kg cheaper in the Best Case scenario)

[1] Average PEM and Alkaline values. Electricity price strategy: response services
[2] Based on UK Short Term Operating Reserve market, scaled for the German market

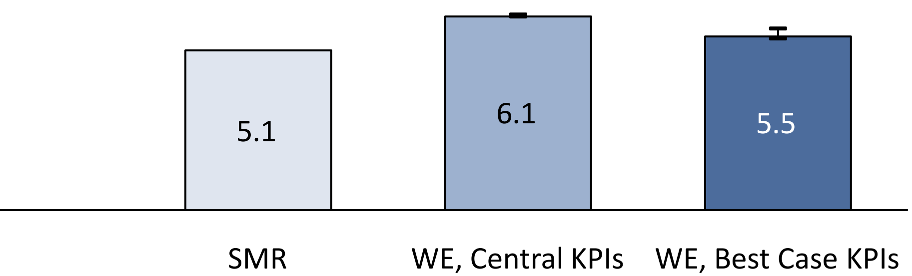
Use case results: 3 – systems for gas injection and large centralised WE production for transport

Germany, 2030

Hydrogen cost [1], €/Kg (CO_2 price excluded)



Hydrogen cost at the nozzle[2], €/Kg (CO_2 price excluded)



3b
10 MW gas grid injection

3c
1000 MW transport

CO_2 price range required for cost parity with natural gas:

3b:
Upper: €300/tCO_2
Lower: €180/tCO_2

3c:
Upper: €115/tCO_2
Lower: €35/tCO_2

Discussion

<u>Gas Injection</u>

- The analysis suggests that water electrolysers are will find it challenging to compete with natural gas injection, regardless of their size, unless otherwise supported via targeted policy intervention (e.g. gas grid decarbonisation targets, renewable heat incentives, CO_2 pricing etc.) or larger system balancing payments than modelled here.
- For example, the analysis suggest that the CO_2 price required to achieve cost parity with gas injection should be ranging between circa € 180 - 300/tCO_2 (depending on the scenario and technology choice)

<u>Transport application</u>

- The analysis also suggest that centralised, large scale (~1000MW) WE systems dedicated to the production of hydrogen for transport application is less cost competitive than smaller ($\leq$20MW) WE systems . This is due to the assumptions that 1) large WE units cannot use their full installed capacity to offer grid balancing services (capped to up to 60MW as discussed in the previous slide) and 2) the system specific Capex (€/MW installed) do not scale with size in the modelling.

1 Average PEM and Alkaline values. Electricity price strategy: response services
2 All costs including compression, distribution and HRS costs

Use case results: 1 – small systems (≤20MW WE) providing hydrogen for transport – costs breakdown

Germany, 2030

Hydrogen cost at the nozzle[1], €/Kg (CO$_2$ price excluded)

	Small car HRS (1MW)			Large car HRS (5MW)			Large bus depot (10MW)			Off-site WE, Delivery to Small car HRS (20MW)		
	SMR	Central KPIs	Best KPIs	SMR	Central KPIs	Best KPIs	SMR	Central KPIs	Best KPIs	SMR	Central KPIs	Best KPIs
Water	2.41	0.02	0.02	2.41	0.02	0.02	2.41	0.02	0.02	2.41	0.02	0.02
Electricity		2.74	2.61		2.74	2.61		2.74	2.61		2.74	2.61
Opex		0.27	0.21		0.11	0.06		0.11	0.06		0.09	0.04
Capex		0.35	0.11		0.35	0.11		0.35	0.11		0.35	0.11
Stack replacement		0.50	0.13		0.50	0.13		0.50	0.13		0.50	0.13
Use Case	2.76	1.81	1.80	2.36	1.42	1.40	2.08	1.15	1.14	2.76	2.63	2.61
Balancing Services	-	- 0.64	- 0.63	-	0.64	- 0.63	-	- 0.64	- 0.63	-	- 0.64	- 0.63

1 PEM Water Electrolysers. Electricity price strategy: response services

Use case results: 2 – systems producing industrial hydrogen – costs breakdown

Germany, 2030

Hydrogen cost at the nozzle[1], €/Kg (CO$_2$ price excluded)

	10 MW			100 MW			250 MW		
	SMR	Central KPIs	Best KPIs	SMR	Central KPIs	Best KPIs	SMR	Central KPIs	Best KPIs
Water	2.41	0.02	0.02	2.41	0.02	0.02	2.41	0.02	0.02
Electricity		2.74	2.61		2.74	2.61		2.74	2.61
Opex		0.11	0.06		0.07	0.03		0.07	0.02
Capex		0.35	0.11		0.34	0.11		0.34	0.10
Stack replacement		0.50	0.13		0.49	0.12		0.48	0.12
Use Case	1.86	1.78	1.77	0.93	0.84	0.84	0.64	0.56	0.55
Balancing Services	-	- 0.64	- 0.63	-	- 0.39	- 0.37	-	- 0.15	- 0.15

1 PEM Water Electrolysers. Electricity price strategy: response services

Use case results: 3 – systems for gas injection and large centralised WE production for transport – costs breakdown

Germany, 2030

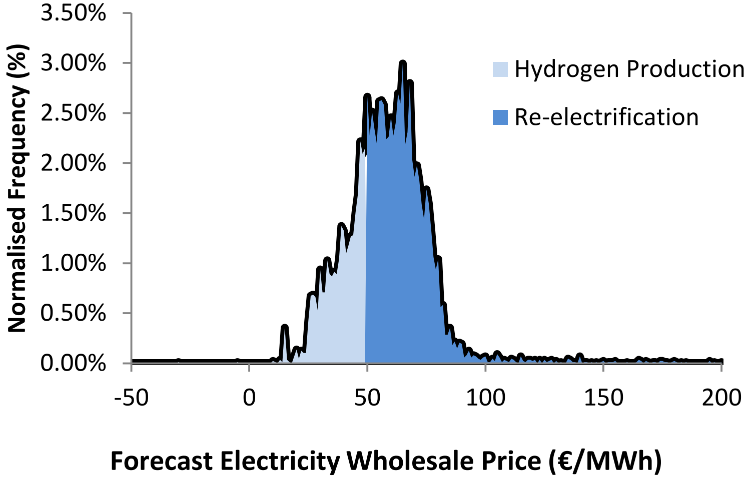
Hydrogen cost at the nozzle[1], €/Kg (CO_2 price excluded)

	Grid Injection (10 MW)			Centralised Transport (1000 MW)		
	Natural Gas	Central KPIs	Best KPIs	SMR	Central KPIs	Best KPIs
Water	1.37	0.02	0.02	2.41	0.02	0.02
Electricity		2.74	2.61		2.74	2.61
Opex		0.11	0.06		0.06	0.02
Capex		0.35	0.11		0.34	0.10
Stack replacement		0.50	0.13		0.48	0.12
Use Case	-	0.31	0.30	2.65	2.55	2.55
Balancing Services	-	- 0.64	- 0.63	-	- 0.04	- 0.04

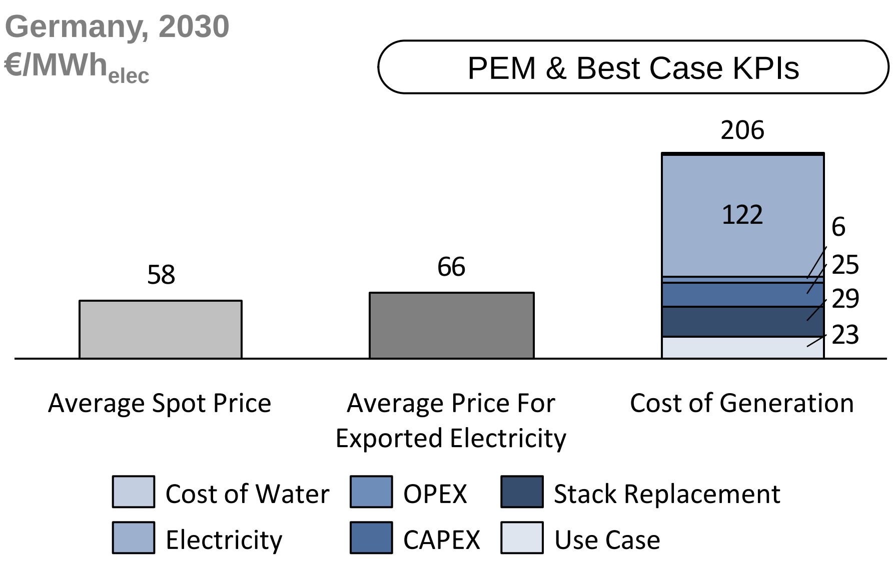
1 PEM Water Electrolysers. Electricity price strategy: response services

Re-electrification is unlikely to be viable in electricity markets with current volatility

Electricity Wholesale Price: Low Volatility, €/MWh



Electricity Price/Cost [1], €/MWh



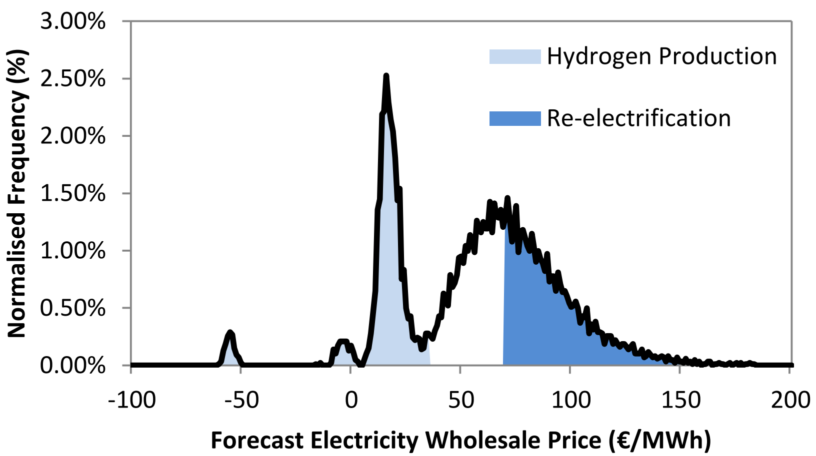
Discussion

- In markets with **current electricity price volatility**, re-electrification using hydrogen as a storage medium is not financially viable, as the spread between high and low electricity prices cannot compensate for the efficiency losses in the system.

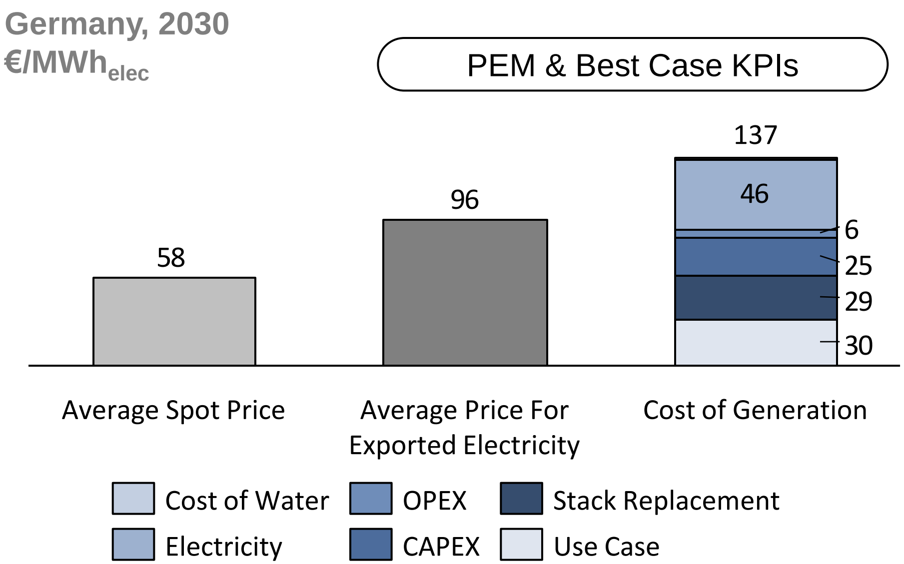
1 Redpoint Energy (2009) – Decarbonising the GB Power Sector

Re-electrification is only likely to be viable in volatile electricity markets and still requires support for provision of energy storage

Electricity Wholesale Price: High Volatility, €/MWh



Electricity Price/Cost [1], €/MWh



Discussion

- In markets with **highly volatile electricity prices** (an example is shown above for Germany, using a graph adapted from an industry forecast for the UK's volatility[1]), re-electrification using hydrogen as a storage medium has value, by producing inexpensive hydrogen during periods with low electricity price, and generating electricity (via a turbine) during periods of high electricity price.

- The cost of electricity from re-electrification, using an optimised strategy, is €41/MWh greater than the average spot price received for the **exported** electricity . The value of energy storage in the electricity network by 2030 is uncertain, and there is potential for re-electrification use cases via hydrogen in highly volatile electricity markets should these services become valuable. Stored electricity would need a value of at least €41/MWh to make this scenario viable.

1 Redpoint Energy (2009) – Decarbonising the GB Power Sector

Germany – overarching conclusions

Transport

- The analysis performed for the German market suggests that the most competitive use case for water electrolysis (WE) is hydrogen production for the transport sector
- Smaller WE units ($\leq$ 20MW) using grid electricity can be competitive with SMR-derived hydrogen by 2030 in Germany regardless of the WE technology, although PEM could offer a more cost effective solution thanks to a greater scope in their cost reduction and efficiency improvement by 2030
- Distributed (on-site) WE units appears to offer a marginally cheaper solution than large ($\geq$ 50 MW) centralised (off-site) WE plants as in the modelled scenarios 1) on-site plants (above 1MW) can access to the same electricity prices and low network charges as for centralised WE plants, 2) the system specific Capex (€/MW installed) does not scale with size, 3) there are no distribution costs for distributed WE and 4) very large MW units are unlikely to use their full installed capacity to offer grid balancing services, as this market is limited in scale.

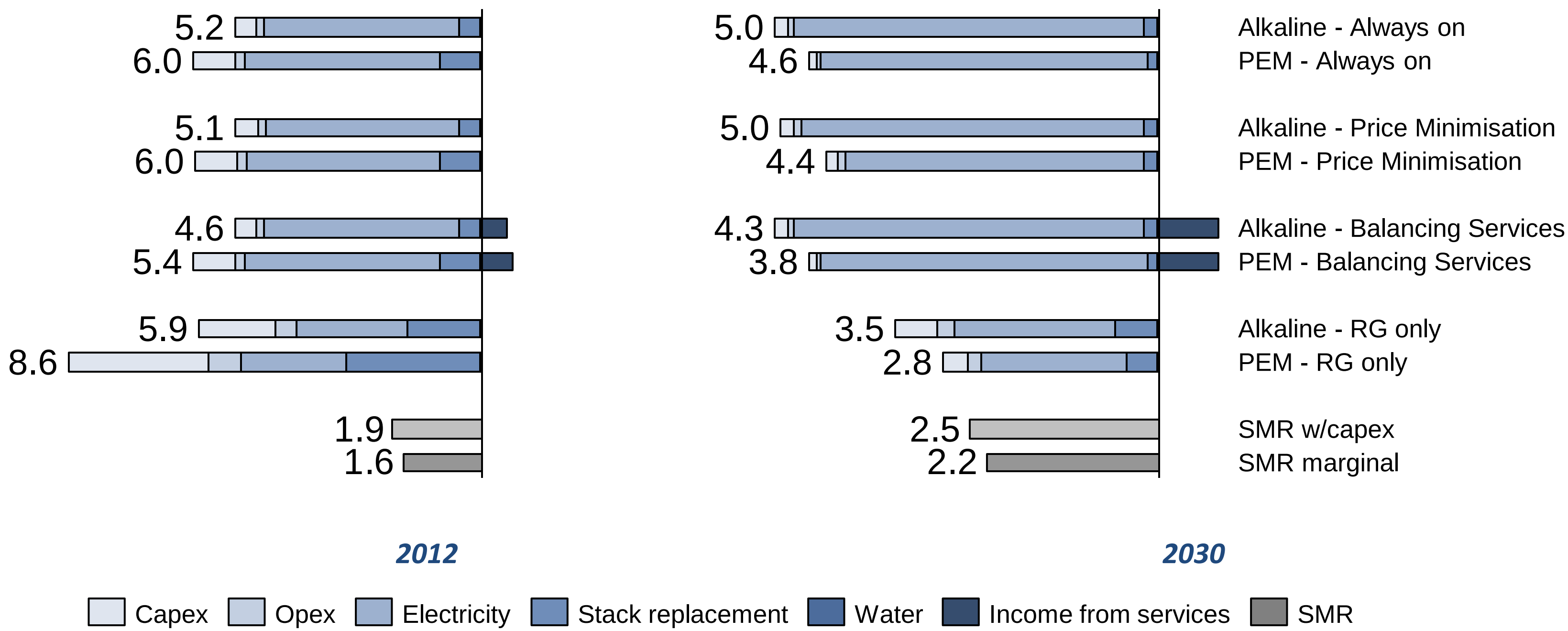
Other applications

- WE will find it challenging to compete against natural gas-based solutions in the other applications analysed in this study by 2030 (hydrogen for industrial consumption and gas injection) unless the best case KPIs are achieved or the sectors is supported by a targeted policy intervention (e.g. gas grid / industrial decarbonisation targets / mandate, renewable heat incentives, CO_2 pricing, etc.) or very high balancing benefits are paid (see below).
- For example, the analysis for the gas injection case suggests that the CO_2 price required to achieve cost parity with gas injection should range between circa € 180-300/tCO2 (depending on the scenario and technology choice)

UK case study – electrolyser operating mode

UK, 2012 and 2030

Hydrogen production cost (€/kg)

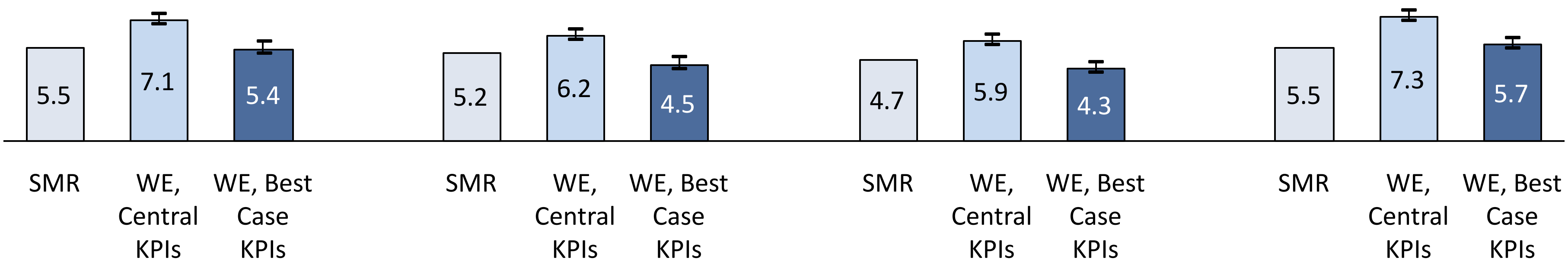


- In the UK, the best strategy in 2012 is for the electrolyser operator to be connected to the electricity grid and to offer balancing services. However, by 2030, the increasing electricity price makes strategies where the electrolyser is instead connected to a dedicated generator more attractive (in this case a 31% load factor wind turbine). Further details of these strategies are given in the appendix.
- The following analysis of hydrogen costs in the 2030 UK market therefore assumes that the electrolyser operator adopts the approach connecting directly and only to a renewable generator via a private wire arrangement

Use case results: 1 – small systems (≤20MW WE) providing hydrogen for transport

UK, 2030

Hydrogen cost at the nozzle[1], €/Kg. Off-Grid System connected to wind farm. (CO_2 price excluded)



1a (on-site 1MW WE)
Small car HRS
400kg/day

1b (on-site 5MW WE)
Large car HRS
2000kg/day

1c (on-site 10MW WE)
Large bus depot
4000kg/day

1d (off-site 20MW WE)
8000 kg/day electrolyser distributes to 20 small HRS

All costs including compression, distribution (for SMR and cases 1d only) and HRS costs. Error bars reflect difference between PEM and Alkaline technology.

Discussion

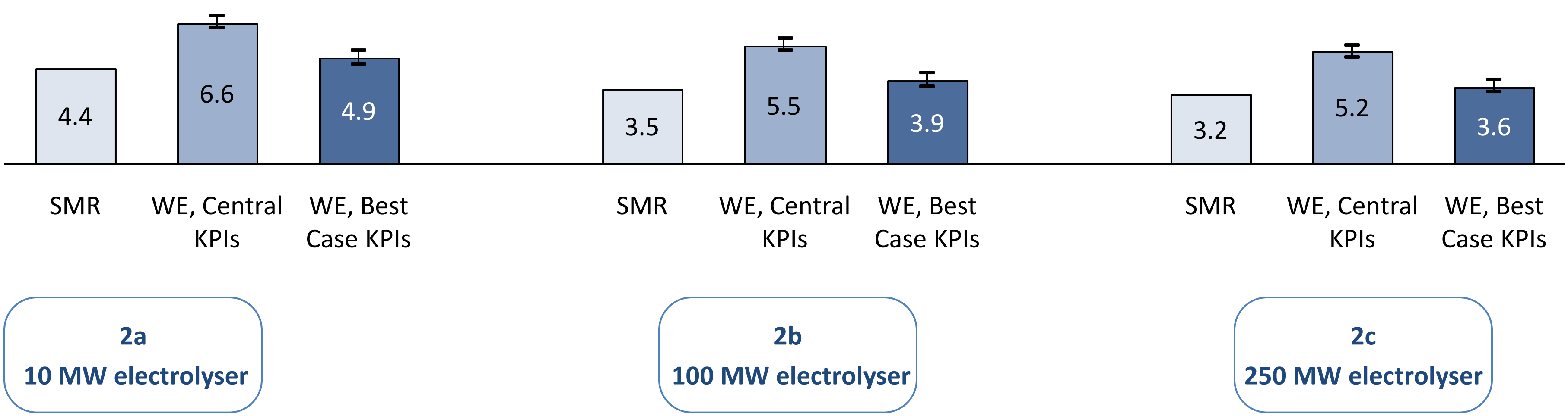
- The analysis suggests that WE technology (both on-site and offsite) powered with off-grid electricity (e.g. WE directly connected to a local renewable generator such as a wind farm) can compete with SMR-derived hydrogen by 2030 in the UK should the WE technology achieve the cost and efficiency improvements implied by the Best Case KPIs scenario.
- Under these assumptions, on-site WE offer a cheaper solution than centralised WE plants as 1) the system specific capex (€/MW installed) does not scale with size; 2) there are no distribution costs and 3) subsidies for wind farms (ROCs) remain at 2012 levels.
- Results also suggest that PEM technology could provide a better proposition than Alkaline technology (circa up to €0.5/kg_{H2} for both the Central and Best Case scenarios). This is because as modelled PEM technology is assumed to offer a wider operational range, via lower minimum load factors, which is better suited to capture volatile renewable generation, therefore increasing annual hydrogen production of the WE plant.
- Carbon price of ~€55/tCO_2 is sufficient for best case KPIs across Use Case 1. For central KPIs, a price between €75-230/tCO_2 is needed

1 Average PEM and Alkaline values. Electricity price strategy: off-grid renewable electricity only (wind farm, 31% load factor), no provision of grid balancing services

Use case results: 2 – systems producing industrial hydrogen

UK, 2030

Hydrogen cost at the nozzle[1], €/Kg. Off-Grid System connected to wind farm. (CO_2 price excluded)



WE are assumed to replace large on-site SMR units to produce industrial hydrogen. No HRS costs included. Scenarios include cost for a hydrogen pipeline connecting plants with the industrial end-use. Scenarios only reflects different WE sizes (from 10MW to 250MW).

Discussion

- The analysis suggests that WE operated in this mode may find it challenging to compete against SMR for industrial hydrogen applications even in the Best Case KPIs scenario in the UK by 2030
- Results suggests that 1) the WE economic performance increases with the WE installed capacity and 2) systems with a lower turn down level perform considerably better in these stand alone cases. In other words, as modelled, large PEM systems (with a 0% turn-down level) are better suited to capture volatile renewable generation than alkaline (modelled at 10%), therefore benefitting from a higher average load factor
- The analysis suggests that the minimum cost gap with SMR is of the order of circa €0.50/kg_{H2} (Best Case KPIs, 250 MW PEM electrolyser), meaning that WE would need additional support from the regulatory framework (e.g. balancing payments, electricity tariffs) or direct policy support top compete in these markets.

1 Average PEM and Alkaline values. Electricity price strategy: off-grid renewable electricity only (wind farm, 31% load factor), no provision of grid balancing services

Use case results: 3 – systems for gas injection and large centralised WE production for transport

UK, 2030

Hydrogen cost [1], €/Kg (CO$_2$ price excluded)

Hydrogen cost at the nozzle[2], €/Kg (CO$_2$ price excluded)

3b
10 MW gas grid injection

3c
1000 MW transport

CO_2 price range required for cost parity with natural gas:

3b	3c
Upper: €600/tCO2	Upper: €250/tCO2
Lower: €250/tCO2	Lower: €5/tCO2

Discussion

Gas Injection

- The analysis suggests that water electrolysers are unlikely to compete effectively with natural gas injection given current price projections, regardless of their size or cost/efficiency improvement, unless otherwise supported via targeted policy interventions (e.g. gas grid decarbonisation targets, renewable heat incentives, CO_2 pricing etc.). For example, the analysis suggest that the CO_2 price required to achieve cost parity with gas injection should range between circa € 250-600/tCO_2 (depending on the scenario and technology choice)

Transport application

- Large scale (≥1000MW) centralised WE systems dedicated to the production of hydrogen for transport applications perform as smaller systems (~ 20MW, see case 1d) but are still less cost competitive than on-site (decentralised) solutions (see cases 1a-c) . As for case 1d, this is because 1) the system specific capex (€/MW installed) are not modelled to scale with size; 2) off-site hydrogen production implies extra hydrogen distribution costs; and 3) additional costs are involved in geological storage in off-site production.

1 Average PEM and Alkaline values. Electricity price strategy: off-grid renewable electricity only (wind farm, 31% load factor), no provision of grid balancing services

Use case results: 1 – small systems (≤20MW WE) providing hydrogen for transport – costs breakdown

UK, 2030

Hydrogen cost at the nozzle[1], €/Kg (CO_2 price excluded)

	Small car HRS (1MW)			Large car HRS (5MW)			Large bus depot (10MW)			Off-site WE, Delivery to Small car HRS (20MW)		
	SMR	Central KPIs	Best KPIs	SMR	Central KPIs	Best KPIs	SMR	Central KPIs	Best KPIs	SMR	Central KPIs	Best KPIs
Water		0.02	0.02		0.02	0.02		0.02	0.02		0.02	0.02
Grid Electricity		-	-		-	-		-	-		-	-
Opex	2.48	0.84	0.66	2.48	0.33	0.18	2.48	0.33	0.18	2.48	0.27	0.12
Capex		1.11	0.34		1.11	0.34		1.11	0.34		1.11	0.34
Stack replacement		1.58	0.40		1.58	0.40		1.58	0.40		1.58	0.40
Use Case	2.99	1.76	1.74	2.58	1.36	1.35	2.24	1.11	1.10	2.99	2.57	2.56
Wind Farm (inc. ROCs)	-	2.06	1.91	-	2.06	1.91	-	2.06	1.91	-	2.06	1.91

- Wind farm costs include capex, opex and subsidies available (Renewable Obligation Certificates for the UK)
- Wind farm costs per kg H_2 higher for central case due to lower electrolyser efficiency.

1 PEM Water Electrolysers. Electricity price strategy: Always on, modulated by electricity availability

Use case results: 2 – systems producing industrial hydrogen – costs breakdown

UK, 2030

Hydrogen cost at the nozzle[1], €/Kg (CO$_2$ price excluded)

	10 MW			100 MW			250 MW		
	SMR	Central KPIs	Best KPIs	SMR	Central KPIs	Best KPIs	SMR	Central KPIs	Best KPIs
Water	2.48	0.02	0.02	2.48	0.02	0.02	2.48	0.02	0.02
Grid Electricity		-	-		-	-		-	-
Opex		0.33	0.18		0.23	0.08		0.21	0.07
Capex		1.11	0.34		1.11	0.34		1.11	0.34
Stack replacement		1.58	0.40		1.58	0.40		1.58	0.40
Use Case	1.95	1.76	1.76	**1.01**	0.83	0.83	**0.73**	0.54	0.54
Wind Farm (inc. ROCs)	-	2.06	1.91	-	2.06	1.91	-	2.06	1.91

1 PEM Water Electrolysers. Electricity price strategy: Always on, modulated by electricity availability

Use case results: 3 – systems for gas injection and large centralised WE production for transport – costs breakdown

UK, 2030

Hydrogen cost at the nozzle[1], €/Kg (CO_2 price excluded)

	Grid Injection (10 MW)			Centralised Transport (1000 MW)		
	Natural Gas	Central KPIs	Best KPIs	SMR	Central KPIs	Best KPIs
Water	1.42	0.02	0.02	2.48	0.02	0.02
Grid Electricity		-	-		-	-
Opex		0.33	0.18		0.21	0.07
Capex		1.11	0.34		1.11	0.34
Stack Replacement		1.58	0.40		1.58	0.40
Use Case	-	0.30	0.30	2.75	2.54	2.54
Wind Farm (inc. ROCs)	-	2.06	1.91	-	2.06	1.91

1 PEM Water Electrolysers. Electricity price strategy: Always on, modulated by electricity availability

UK – overarching conclusions

Transport

- As with Germany, the analysis suggests that the best application for water electrolysis (WE) in the UK is hydrogen production for the transport sector (Use case 1a-1d)
- Due to the higher wholesale electricity prices and electricity transmission/distribution charges (see Appendix) water electrolysers are likely to be cost competitive compared to centralised SMR production when
    1. Technologies achieve the cost and efficiency improvements implied by the Best Case KPIs scenario
    2. Powered with low cost electricity close to the point of generation (e.g. WE directly connected to a local renewable generator such as a wind farm)
    3. With larger policy or regulatory support to lower the effective price of electricity to grid connected electrolysers
- Water electrolyser technologies that offer a wider operational range via lower minimum load factors appear better suited to capture volatile renewable generation in off-grid scenarios, and therefore ensure a higher annual load factor.

Other applications

- WEs are unlikely to compete against natural gas-based solutions (Use case 2a-2c, 3b) in the other applications analysed in this study by 2030 (hydrogen for industrial consumption and gas injection) unless supported by a targeted policy intervention (e.g. gas grid / industrial decarbonisation targets / mandate, renewable heat incentives, CO_2 pricing, etc.)

Factors affecting price: 1. Volatility - hydrogen cost from WE can be further reduced by having access to volatile electricity prices

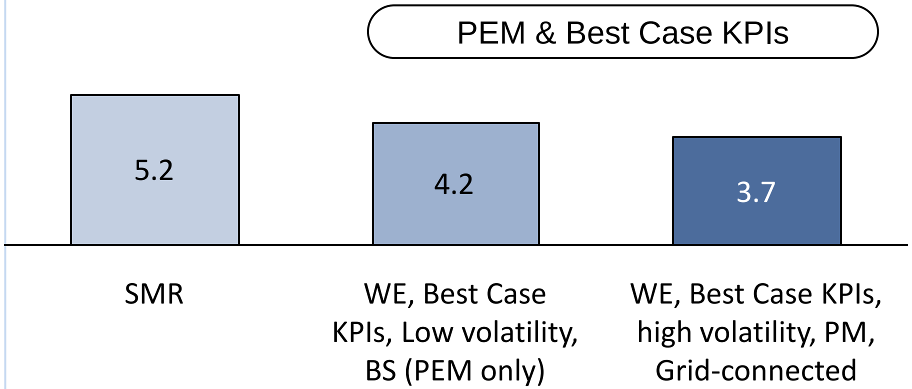
Context and emerging conclusions

- The preceding analysis is based on a world where the volatility of electricity prices does not change significantly.
- The analysis suggest that the economic performance of water electrolysers can be greatly improved in high electricity price volatility scenarios (see slides in the introduction for volatility assumptions)
- In these circumstances, price minimisation (PM) strategies (i.e. turning the electrolyser off when the spot price goes above a certain threshold) can give access to below-average electricity tariff s
- The cost reduction potential available by exploiting volatile electricity prices is higher for technologies not subject to a minimum load factor, meaning that the system can be reactively easily switched on/off to follow the best available tariff
- Overall the analysis suggests that in Germany in a volatile grid world, a PM strategy executed with PEM technology can achieve a hydrogen cost reduction as high as up to **~ €0.5/kg H_2** in the Best Case KPI scenario
- In the UK, the reduction is larger (~1.5€/kg compared to on-grid options) allowing a WE sourcing grid electricity to 1) reach an economic performance close to WE systems powered with off-grid electricity and 2) be close to competitive against centralised SMR.

Hydrogen cost at the nozzle[1], €/Kg

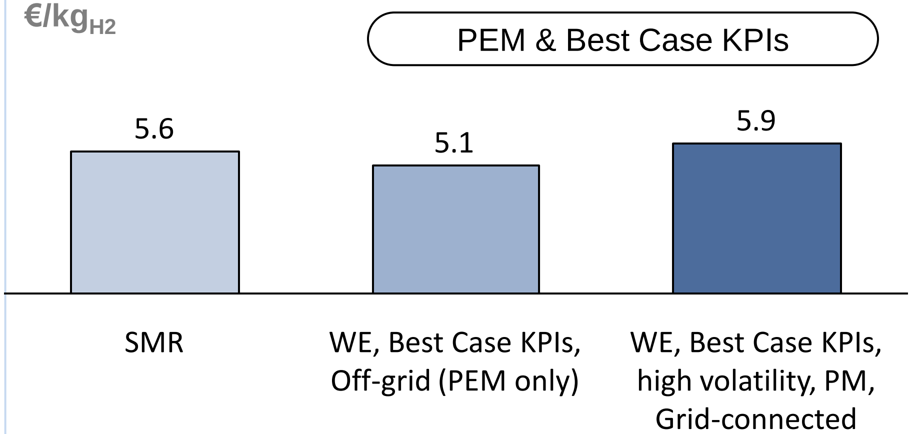
Case 1a, Germany, 2030

€/kg_{H2}



Case 1a, UK, 2030

€/kg_{H2}

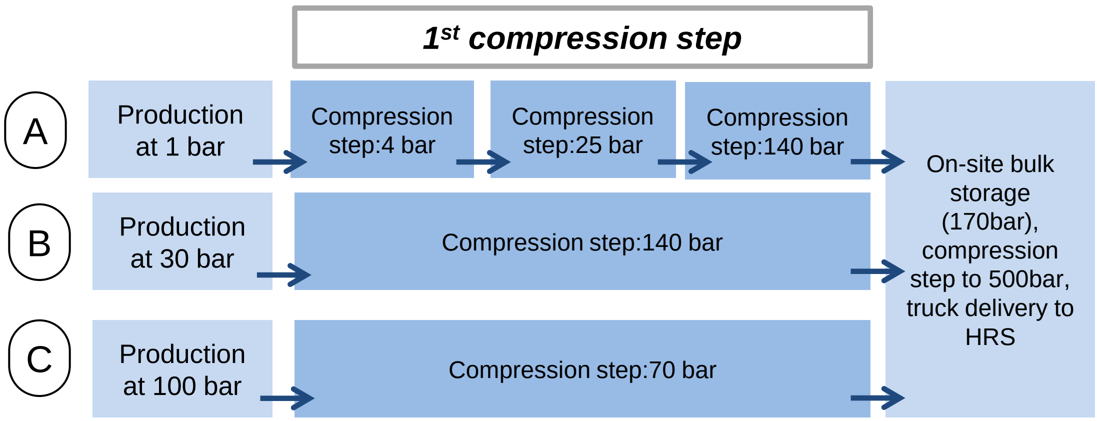


BS = balancing services; PM = price minimisation

Factors affecting price: 2. outlet pressure - Increasing WE outlet pressure leads to relatively small reductions in hydrogen costs

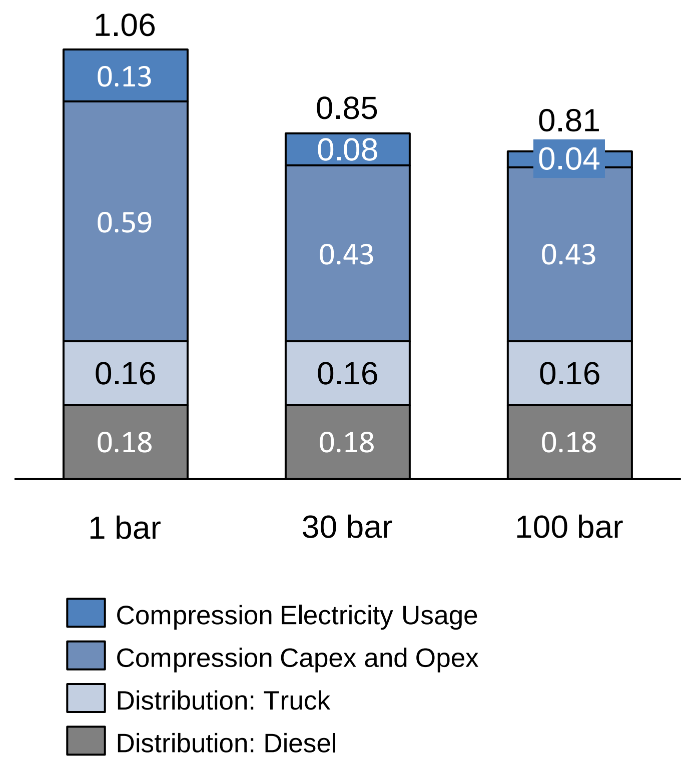
Context and emerging conclusions

- Data gathered for PEM electrolysers suggest that future systems could produce hydrogen at a higher pressures with little efficiency penalty (self pressurised systems).
- In these circumstances, less electrical energy is required in the first compression step up to the on-site bulk storage pressure.
- Depending on the electrolyser output pressure, some cost reduction can be expected from compressor capex/opex, though it would still be necessary to procure a compressor of some form even at the highest output pressure.
- Savings in compression costs are likely to be in the order of ~€0.20/kg$_{H2}$ when moving from 1 to 30 bar, and an further reduction of ~€0.05/kg$_{H2}$ when moving from 30 to 100 bar pressures.



Compression and Distribution Costs, €/kg$_{H2}$

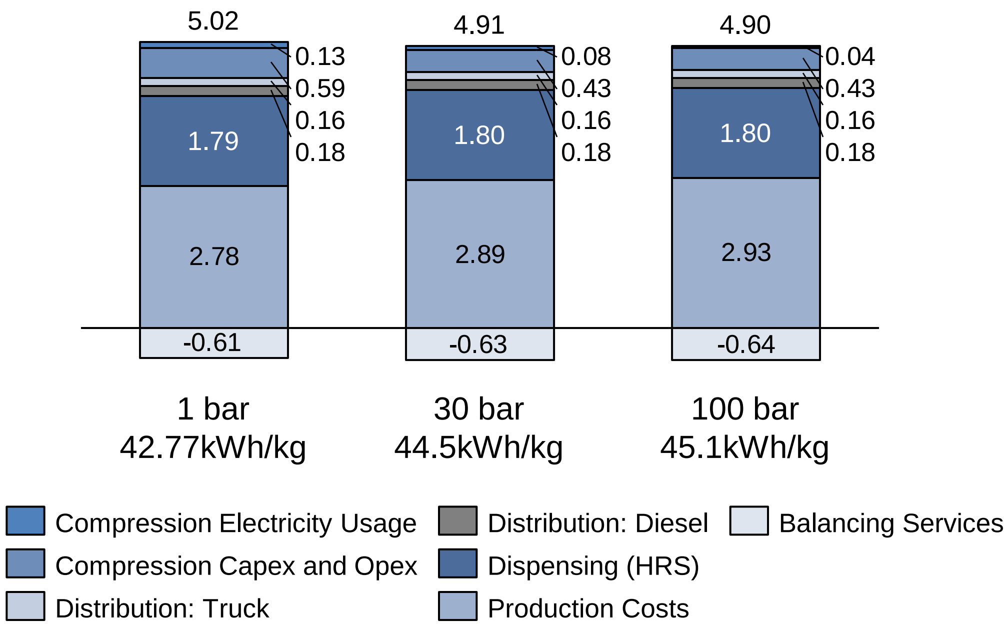
Pathway investigated: **delivery via gaseous truck (1d)**

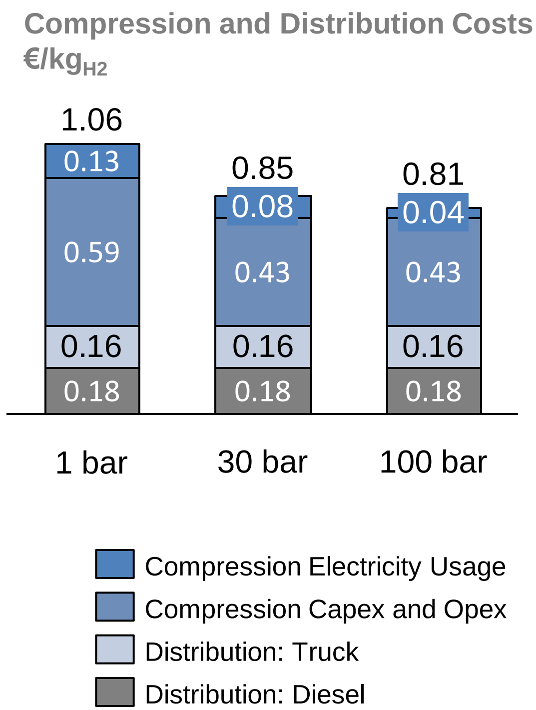


Factors affecting price: 2. outlet pressure - Increasing WE outlet pressure leads to relatively small reductions in hydrogen costs

PEM - Hydrogen cost at the nozzle, €/Kg

Pathway investigated: **delivery via gaseous truck (1d)**





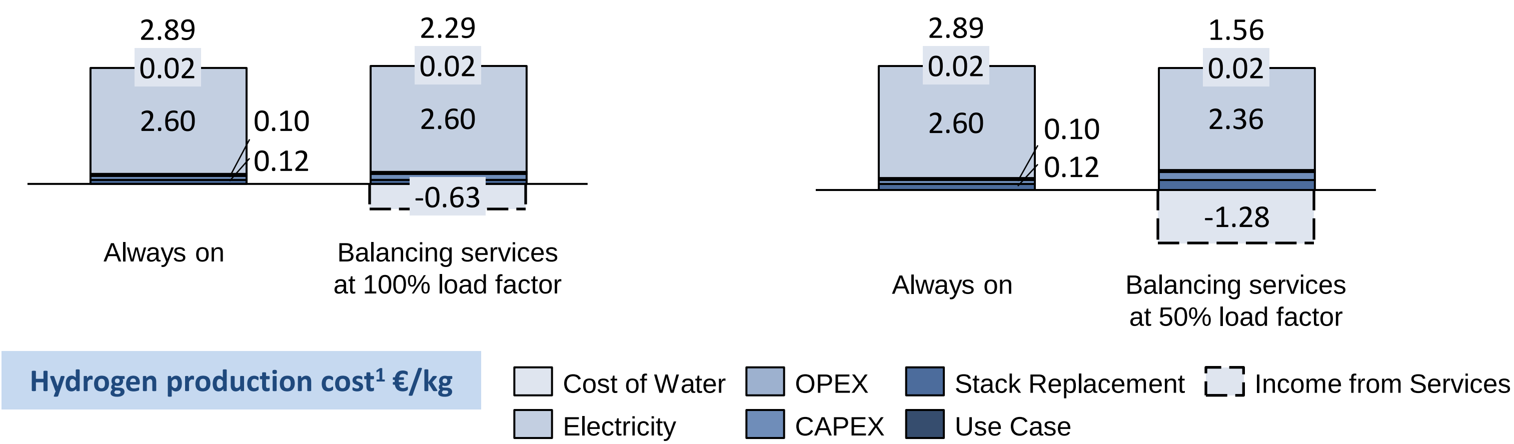
Discussion

- By increasing output pressure from 1 bar to 100 bar, ~€0.25/kg$_{H2}$ in compressor capex/opex and electricity consumption costs can be avoided.
- However, *internal* electrochemical compression in the electrolyser results in a higher specific electricity input required (higher voltage required) compared to unpressurised operation, indicated on the graph label for each pressure.
- Reduction in compressor cost is partially offset by higher energy input required per kg H_2, leading to an increase in production costs.
- Modest reductions in hydrogen cost at the nozzle, on the order of €0.10/kg$_{H2}$ can be expected by moving from systems with 1 bar to 100 bar output pressure.

Note: Compression and distribution costs derived from DOE H2A model

Factors affecting price 3 – Increasing access to balancing services - Electrolyser operating mode could increase the balancing values

	Germany, 2030 – mode 1 **Electrolyser always on 100% to provide balancing services (as modelled above)**	**Germany, 2030 – mode 2** **Electrolyser always on at 50% load factor to maximise efficiency while securing revenues from balancing services[2]**
Mode of operation	Assumes electrolyser is operating with a 100% load factor, and offering 100% of it's rated power as positive reserve	Electrolyser is operated with a 50% load factor, and offers 50% of its rated power as positive reserve, and 50% of its rated power as negative reserve. This allows the operator to benefit from the same amount of revenue as in mode 1, but as the hydrogen produced is half of that in mode 1, the benefit per kg of hydrogen is doubled. Increased efficiency at this 50% set point can offset the additional capex burden[2]
Value of balancing services in 2030 - PEM		

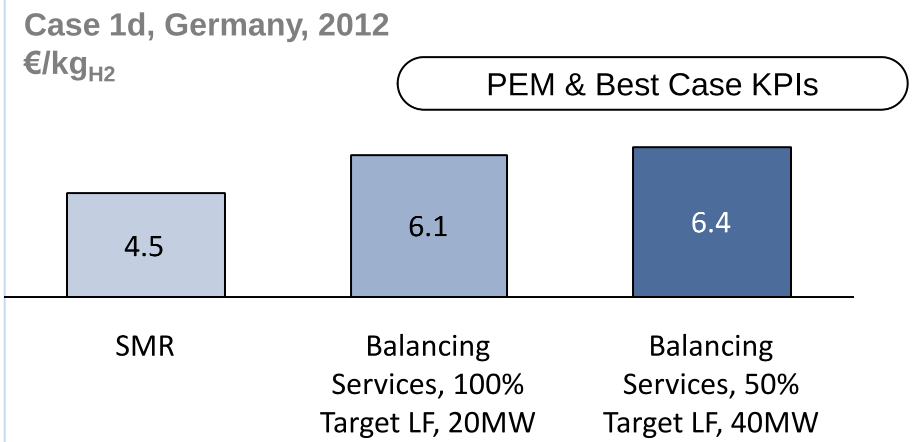


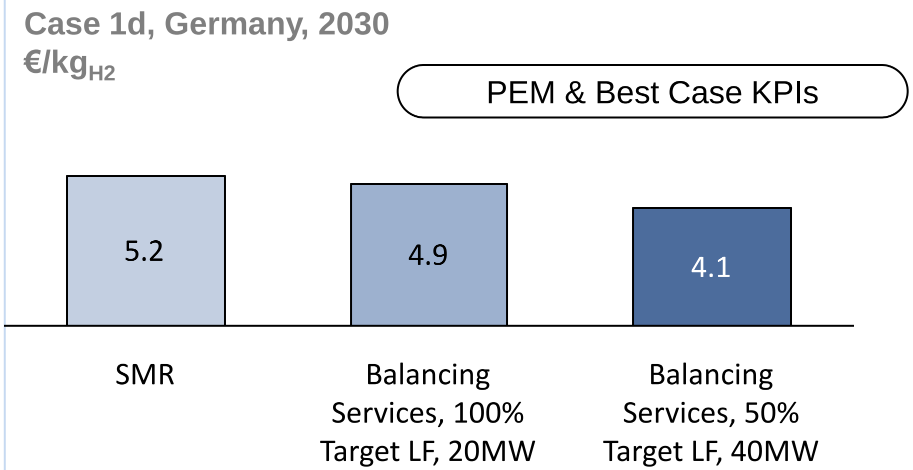
[1] Hydrogen costs based on **PEM** technology, best case KPIs, with no end use costs

[2] Operating at a 50% load factor allows the operator to take advantage of the improved part-load efficiency of electrolysers, especially for alkaline electrolysers. However, in most cases, the €/kg capital cost increases resulting from the lower load factor are greater than the electricity cost saving, and so the impact is small.

Factors affecting price 3 – Electrolyser operating mode could increase the balancing values considerably for the transport case

Hydrogen cost at the nozzle[1], €/Kg





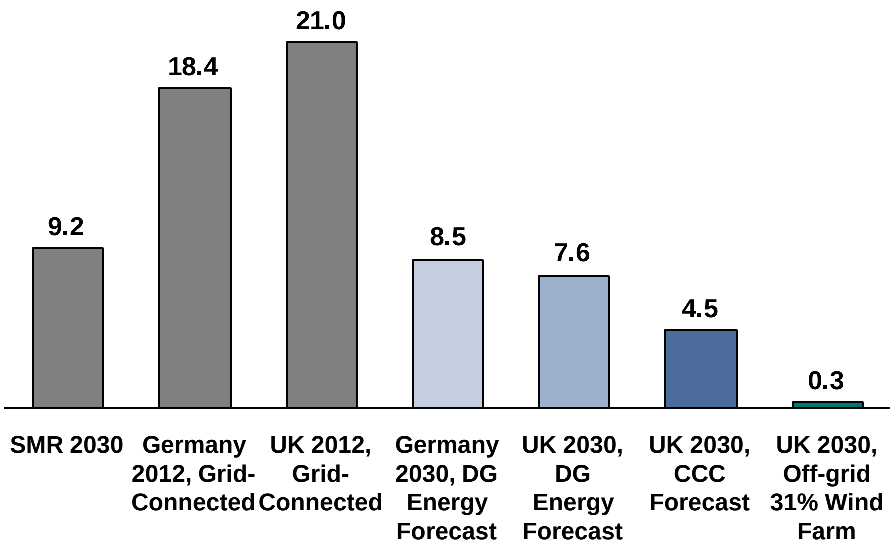
Balancing services limited to a maximum of 60MW per Water Electrolyser.

Context and emerging conclusions

- The following analysis is based on a PEM water electrolyser with 10% lower energy input requirement at 50% load factor.
- The system is sized to satisfy all demand required by the use case, accounting for 50% load factor.
- With 2012 performance and costs, no benefits are expected from operating at part load, even if lower energy input at part load is witnessed.
- Given 2030 performance and costs (reduced energy input per kg hydrogen at rated power, lower capex), the cost of hydrogen can be reduced by up to €0.9/kg_{H2}.
- A combination of reduction in capex, improved energy input per kg of hydrogen and an optimised operating strategy is likely to far outweigh the forecast increases in electricity price.
- Balancing services provides benefits of €1.3/kg_{H2} and €0.6/kg_{H2} at 50% and 100% target load factors, respectively.

Carbon intensity of hydrogen can be reduced by decarbonising the grid or using renewable electricity sources

Embedded CO_2 per kg H_2 (kg CO_2 / kg H_2)



Assumptions:

- PEM & Best Case KPIs, with Response Services, Grid-connected unless stated
- Germany 2030, DG Energy Forecast[1] – Grid CO_2 intensity: 190g/kWh
- UK 2030, DG Energy Forecast[1] – Grid CO_2 intensity: 170g/kWh
- UK 2030, Committee for Climate Change Forecast – Grid CO_2 intensity: 100g/kWh
- UK 2030, Off-grid 31% wind farm – Generator CO_2 intensity: 7g/kWh

Discussion

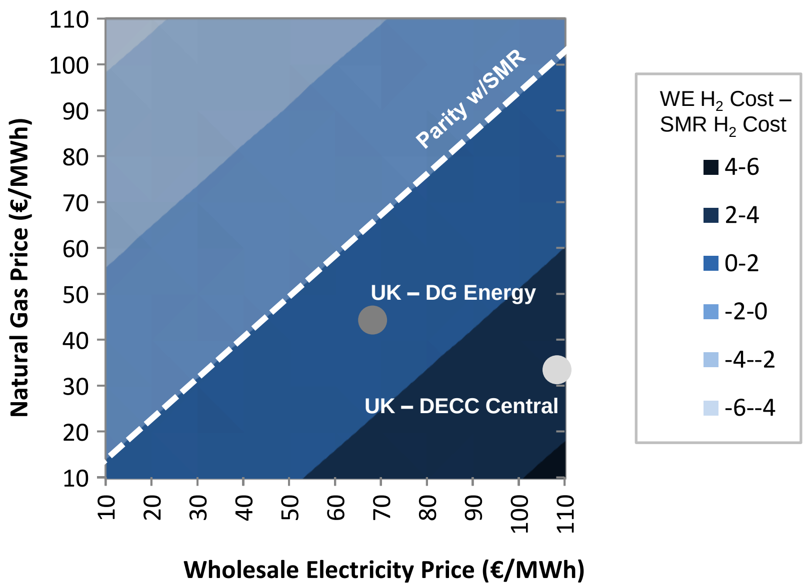
- Today's grid intensity figures imply a higher CO_2 intensity for grid connected electrolysers than SMR (approx 100% higher)
- However, this may overstate the case, as if electrolysers are providing grid services, they are offsetting other potentially more carbon intensive ways of providing the same services.
- Further work is required to quantify the benefits of electrolysers to the grid in this case.
- Even in 2012, it is possible to source 100% green electricity and hence decarbonise the hydrogen generated.
- With projected decarbonisation targets in both the UK and Germany, this conclusion is reversed by 2030 and grid connected water electrolysers can offer significant carbon benefits per unit of hydrogen (depending on which CO_2 intensity projection is used)
- Alternatively, electrolysers which are directly linked to renewable generators, and import little/no electricity from the grid can produce hydrogen with very little embedded CO_2 per kg.

1 European Commission – Directorate General of Energy, "EU Energy Trends to 2030", Update 2009

- Introduction to the techno economic model and data
- Results of the techno-economic modelling
- Target setting: sensitivity of the hydrogen price to the key parameters
- Conclusions
- Appendices
    - Energy markets and data
    - Electrolyser operating modes

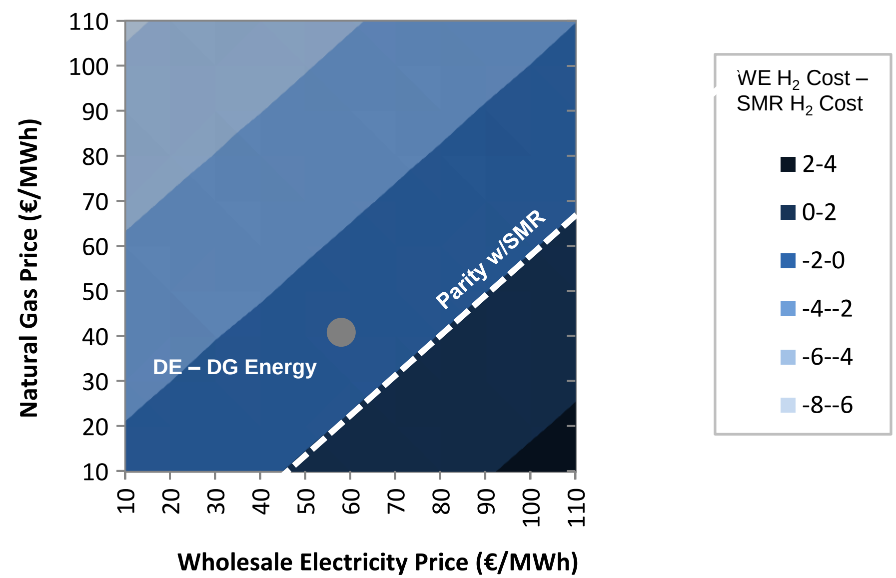
Competitiveness of electrolysers is fundamentally affected by the costs of natural gas and electricity (transport case)

Different in H_2 cost between WE and SMR, €/kg
Use Case 1a, UK, 2030, Grid Connected



PEM & Best Case KPIs, with Response Services

Different in H_2 cost between WE and SMR, €/kg
Use Case 1a, Germany, 2030, Grid Connected



PEM & Best Case KPIs, with Response Services

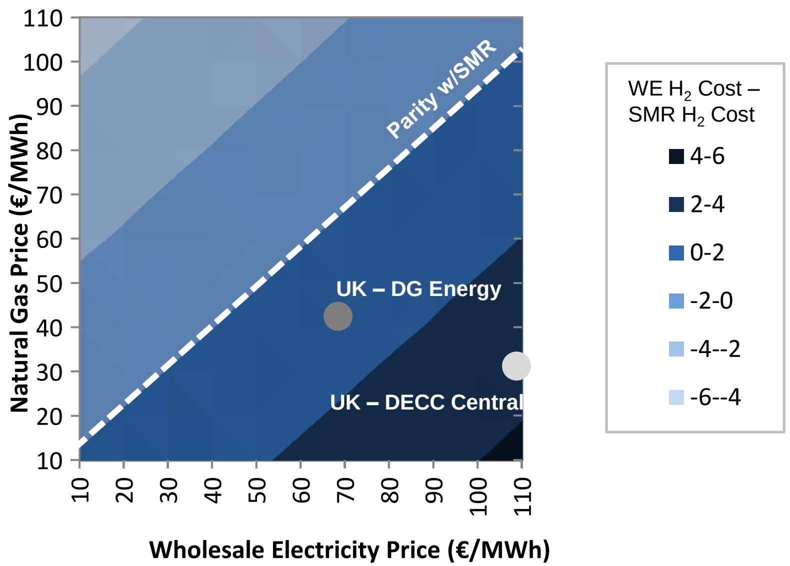
Discussion

- Grid-connected water electrolysers are sensitive to both natural gas price (for counterfactual SMR production) and wholesale electricity cost. **In this grid-connected scenario**, some barriers to cost parity with SMR remain in the UK, in the form of high network charges. With moderate support or revisions to the regulatory regime as in Germany , **distributed grid-connected systems** can challenge SMR on cost terms in transport applications. In the UK, transmission and distribution network charges add substantially to the total electricity cost, hence a lower wholesale electricity price is required to achieve parity than in Germany.
- Two projections for electricity and natural gas prices from DG Energy[1] and DECC[2] are plotted for the UK and Germany– DECC does not publish projections for Germany.

1 DG Ener – REF
2 Department of Energy and Climate Change – REF

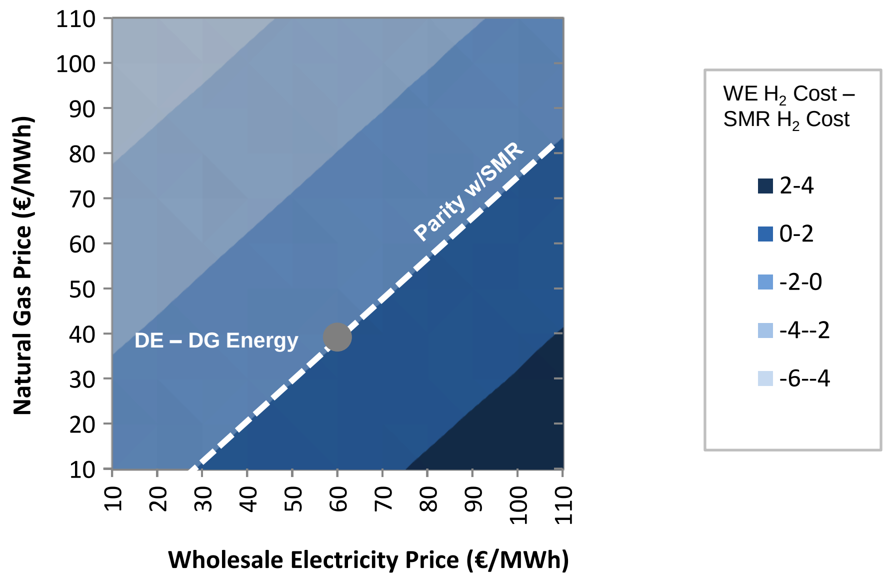
The use of electrolyser for industrial hydrogen is similarly affected

Different in H_2 cost between WE and SMR, €/kg
Use Case 2a, UK, 2030, Grid Connected



PEM & Best Case KPIs, with Response Services

Different in H_2 cost between WE and SMR, €/kg
Use Case 2a, Germany, 2030, Grid Connected



PEM & Best Case KPIs, with Response Services

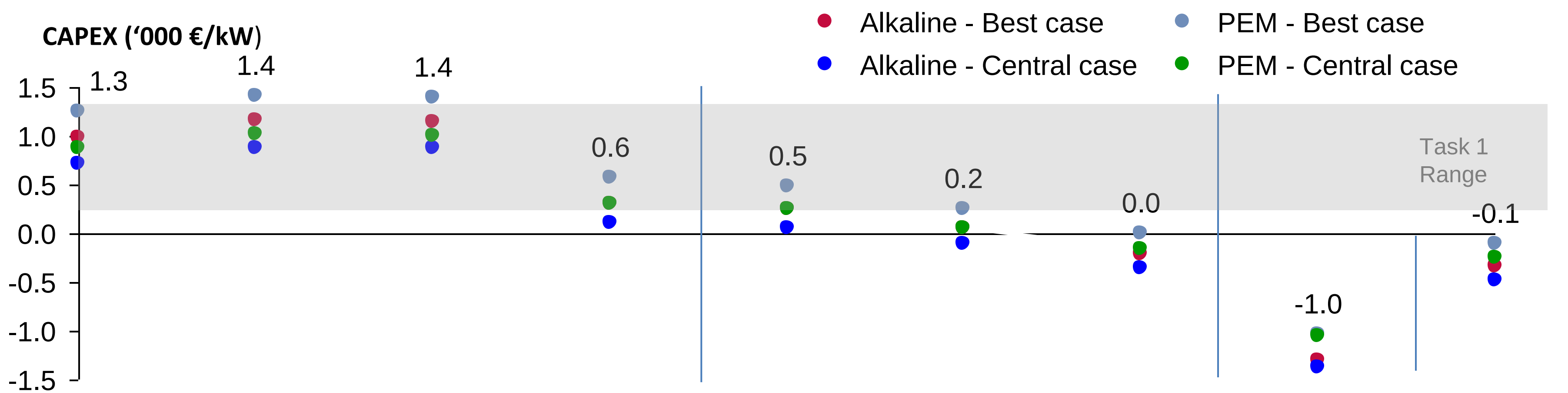
Discussion

- In the UK, **grid-connected** water electrolysers appear far from bring competitive with SMR in provision of industrial heat, due in part to high network charges when connected to the grid.
- In Germany, targets in line with Task 1 or small changes in the electricity or natural gas price could lead to such systems being viable.

Target setting – CAPEX thresholds to achieve parity with counterfactuals

Germany, 2030

Alkaline and PEM Water Electrolysers – Grid Connected



Case 1a (1MW)	Case 1b (5MW)	Case 1c (10MW)	Case 1d (20MW)	Case 2a (10MW)	Case 2b (100MW)	Case 2c (250MW)	Case 3b (10MW)	Case 3c (1000MW)
Transport applications				**Industrial hydrogen applications**			**Gas injection**	**Transport**

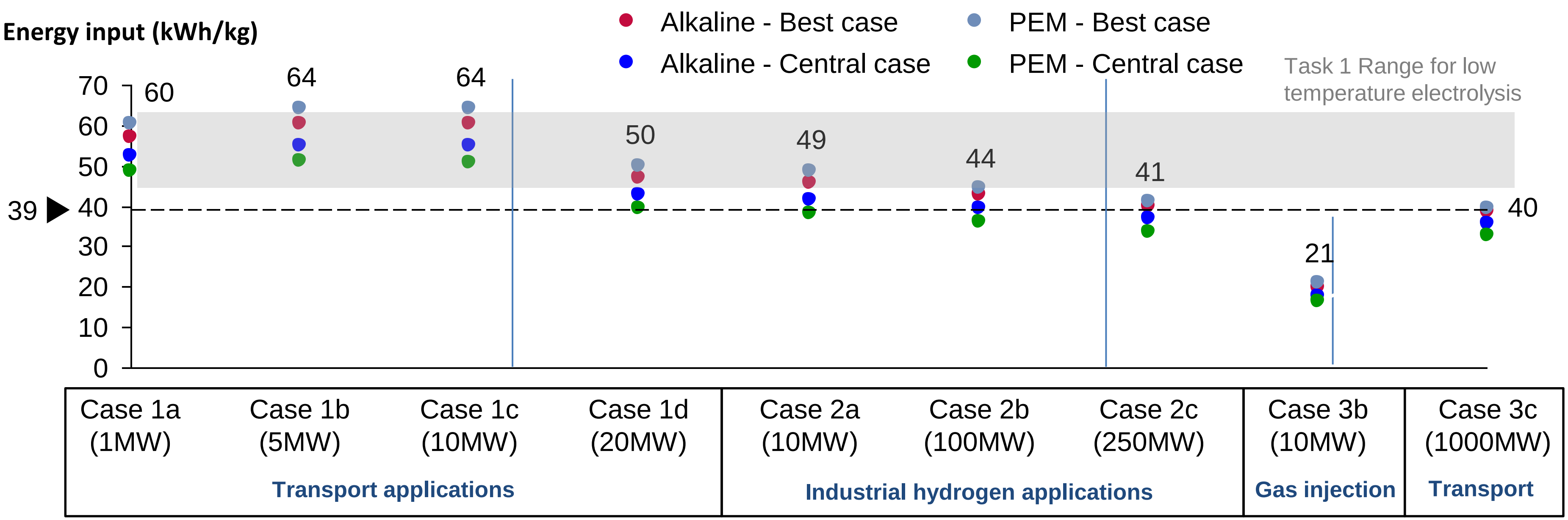
Discussion

- The graph shows the Capex level required so that each use case competes with the counterfactual when assuming either best case or central values for all of the other KPIs for the two WE technologies (PEM and Alkaline)
- The analysis confirms that the best application for water electrolysis (WE) is hydrogen production for the transport sector, with a preference for on-site production (to avoid distribution costs)
- All of the other use cases either requires very low (~ €100/kW) or negative Capex levels

Target setting – Energy input thresholds to achieve parity with counterfactuals

Germany, 2030

Alkaline and PEM Water Electrolysers – Grid Connected



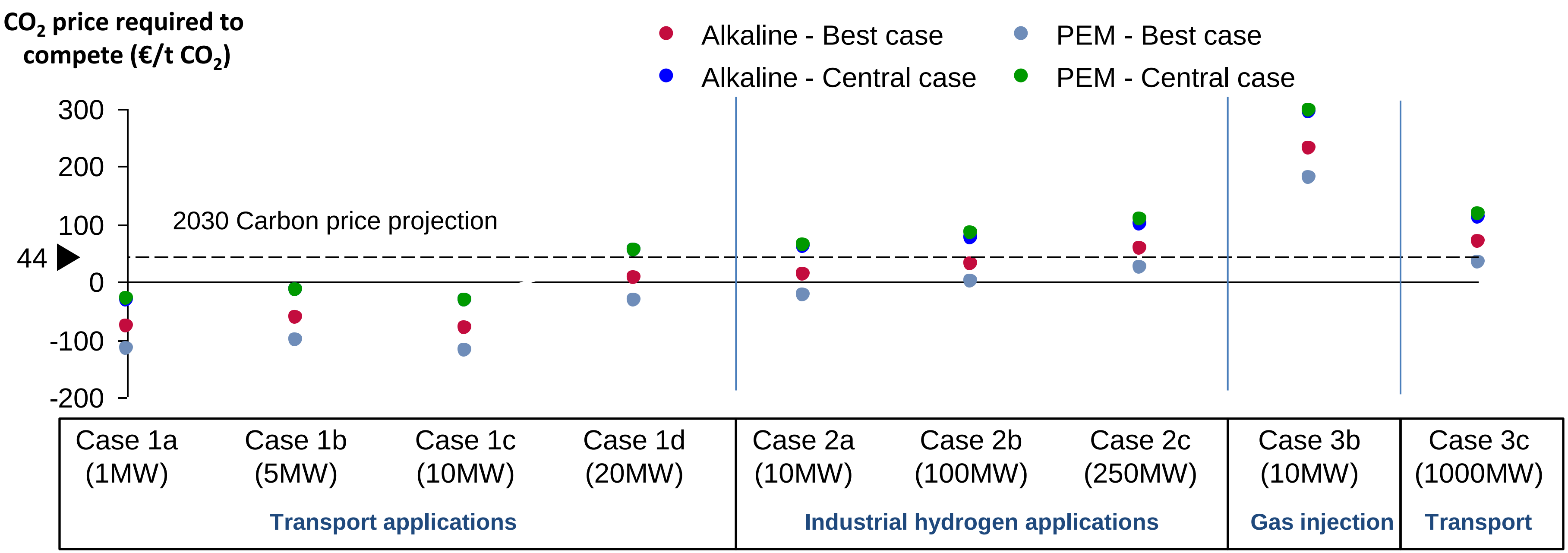
Discussion

- The graph shows the energy input (kWh/kg) required so that each use case competes with the counterfactual when assuming either best case or central values for all of the other KPIs for the two WE technologies (PEM and Alkaline)
- The analysis confirms that the most competitive application for water electrolysis (WE) is hydrogen production for the transport sector, while many applications require energy inputs outside the range gathered in Task 1 (PEM, Alkaline).
- For the depicted technologies all required energy is supplied in electrical form, which results in a minimum electrical energy input of 39.4 kWh/kg. The required electrical energy input may be reduced below 39.4 kWh/kg if suitable heat is provided to the system.

Target setting – Carbon price to achieve parity with counterfactuals

Germany, 2030

Alkaline and PEM Water Electrolysers – Grid Connected



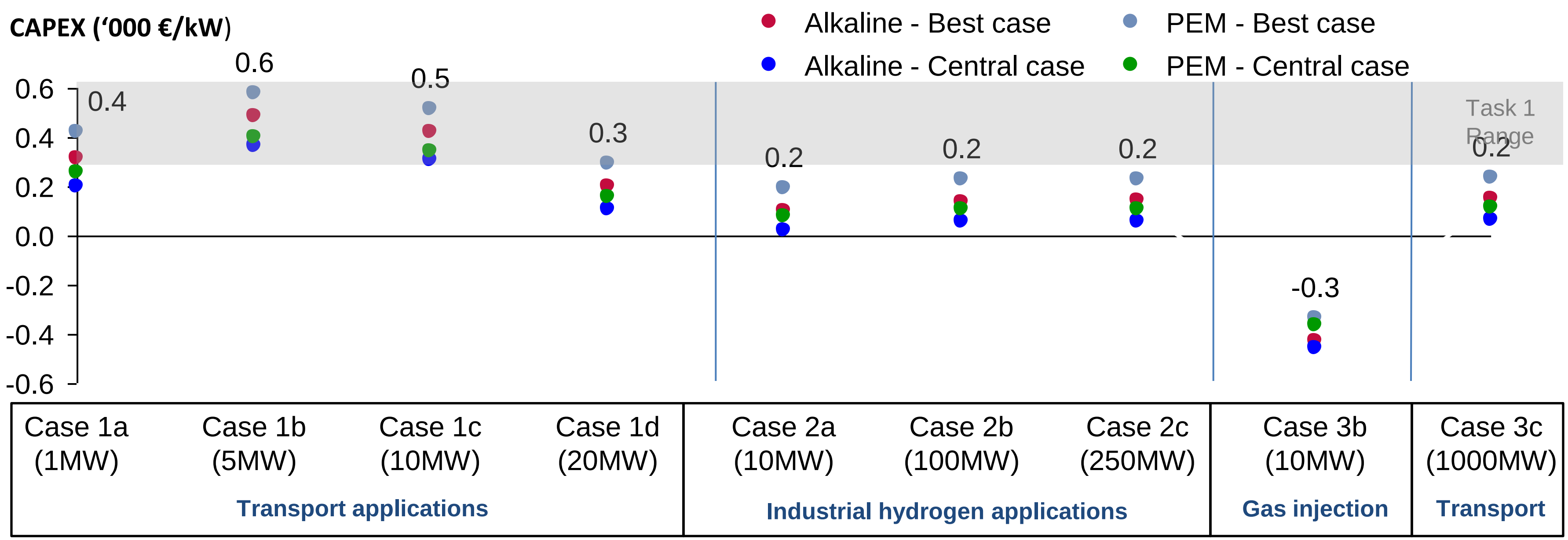
Discussion

- The graph shows the CO_2 price required so that each use case competes with the counterfactual when assuming either best case or central values for all of the other KPIs for the two WE technologies (PEM and Alkaline)
- With best case KPIs the industrial use cases are within the range of the expected carbon price in Germany in 2030 – suggesting that they are within reach of policy intervention.
- A similar conclusion applies to large scale transport applications, though for these applications, the central KPIs are some way from a plausible carbon price.
- Gas injection applications do not appear competitive with the counterfactual due to the relatively small increase in gas price by 2030, and the low embedded CO_2 content of natural gas.

Target setting – CAPEX thresholds to achieve parity with counterfactuals

UK, 2030

Alkaline and PEM Water Electrolysers – Off-grid, 31% Wind Farm Connection



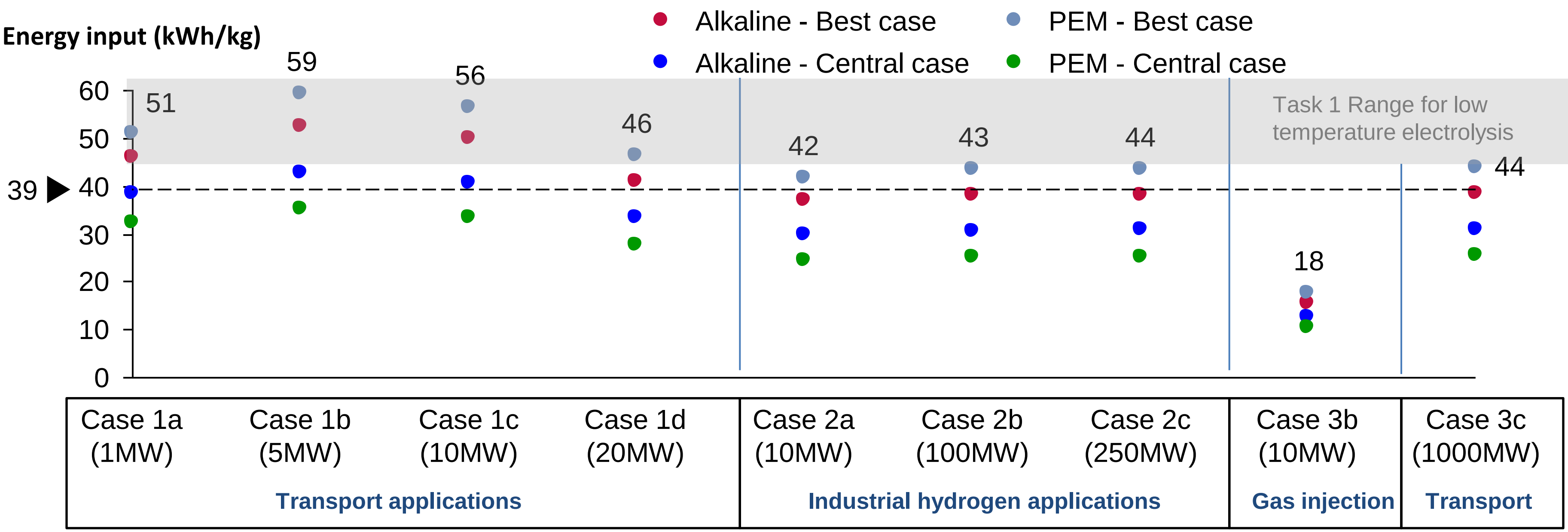
Discussion

- The graph shows the Capex level required so that each use case competes with the counterfactual when assuming either best case or central values for all of the other KPIs for the two WE technologies (PEM and Alkaline)
- The analysis confirms that the best application for water electrolysis (WE) is hydrogen production for the transport sector, with a preference for on-site systems as for the German case
- All of the other use cases either requires very low (~ €100/kW) or negative Capex levels

Target setting – Energy input thresholds to achieve parity with counterfactuals

UK, 2030

Alkaline and PEM Water Electrolysers – Off-grid, 31% Wind Farm Connection



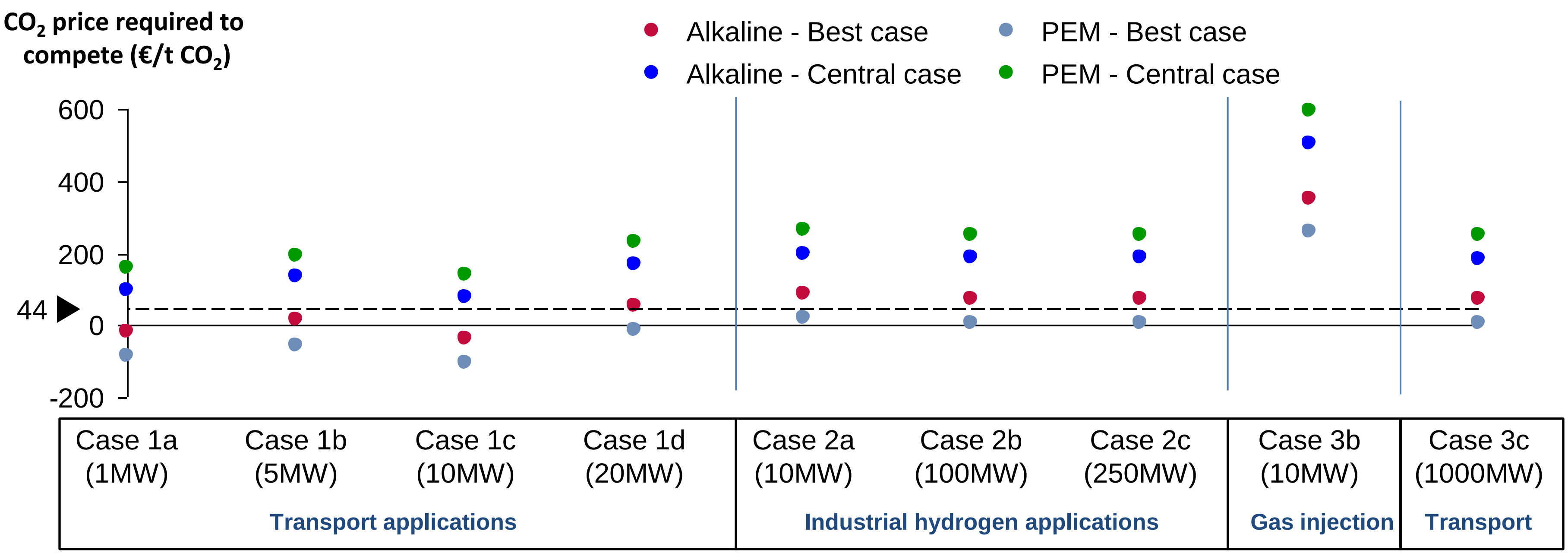
Discussion

- The graph shows the energy input (kWh/kg) required so that each use case competes with the counterfactual when assuming either best case or central values for all of the other KPIs for the two WE technologies (PEM and Alkaline)
- The analysis confirms that the best application for water electrolysis (WE) is hydrogen production for the transport sector
- Industrial hydrogen applications and large off-site WE for transport applications could become more economically viable should the efficiency of the WEs achieve best case KPIs an energy input of less than 40 kWh/kg (e.g. close to 100% efficiency) . All of the other use cases requires unphysical (greater than 100%) efficiencies (this assuming the H2 energy content ~ 39.4 kWh/kg HHV)

Target setting – Carbon price to achieve parity with counterfactuals

UK, 2030

Alkaline and PEM Water Electrolysers – Off-grid, 31% Wind Farm Connection



Discussion

- The graph shows the CO_2 price required so that each use case competes with the counterfactual when assuming either best case or central values for all of the other KPIs for the two WE technologies (PEM and Alkaline)
- For the transport case, best case KPIs are required to bring the end sue within the rang of predicted carbon prices.
- Very best case KPIs could bring the industrial cases within range of carbon price based policies.
- For gas injection a higher than predicted carbon price is required even for the best case KPIs – due to the relatively low CO_2 content of natural gas at 56 t-CO_2/TJ.

- Introduction to the techno economic model and data
- Results of the techno-economic modelling
- Target setting: sensitivity of the hydrogen price to the key parameters
- Conclusions
- Appendices
    - Energy markets and data
    - Electrolyser operating modes

Conclusions (1/4) – the effectiveness of electrolysers is linked to the price of electricity, network services and gas

- The techno-economic modelling reveals the sensitivity of any conclusions on the viability of different electrolyser uses to the assumptions about industrial electricity and gas prices in different markets.
- The price of these commodities is a regulatory issue, particularly for electricity. For example, the exemptions from taxes and network charges that can be available to an electrolyser operator in Germany can lead to an input electricity cost approximately 50% lower than the equivalent operator in the UK.
- The cost of balancing services will affect the strategy adopted for generating hydrogen and this again is affected by regulation. In 2012, the best strategy for operating electrolysers appears to be operating at high load factor to provide balancing services – this mode allows a high load factor for the electrolyser (which ensures good utilisation of a capital intensive asset), whilst reducing the effective price of electricity for the system. This conclusion only applies in markets where balancing services apply for demand response. In markets such as Poland, this is not possible and hence electrolysers will struggle to compete without a change in the regulatory regime.
- Unless the price of electricity becomes more volatile, it is likely that in Germany (for example), the strategy of continued reliance on providing balancing services will remain valid until 2030. There may be strategies to increase the value of balancing services as the cost of electrolyser decrease, which allows operation at lower load factors (e.g. 50%). At this point, the efficiency of the system is increased and it may be possible to access both positive and negative balancing benefits (by turning the electrolyser up or down), which increases the overall value of balancing services per kg of hydrogen produced.

Conclusions (2/4) – as electrolyser capital costs decrease, the value of an ability to modulate across the power range increases

- In markets with higher industrial electricity prices due to higher network charges and taxes, a search for cheaper electricity is required. Here, as the cost of electrolysers decrease, options to generate hydrogen at the point of electricity generation (effectively offering a different market for the electricity generator)using responsive electrolysers operated at lower load factors appear most viable.
- In each case, there appears to be a trend towards electrolysers operating at lower load factors and away from their set point input, suggesting a need to be able to modulate inputs over a wide range. Furthermore, the analysis suggests that a low turn-down ratio is particularly important for electrolysers connected to very volatile sources of electricity (e.g. a wind farm) .

Transport End Use

- The analysis of use cases suggests that electrolysers will enjoy the most favourable markets in the transport sector, where the energy value of their products is higher.
- Here, in Germany using 2030 projections and even with central KPIs electrolysers appear able to compete with the incumbent option of generating hydrogen in large central SMR plants and distributing to filling stations.
- In other markets with more expensive electricity, the best case KPIs for electrolyser capex and efficiency appear to be required to ensure competition with SMR (in the absence of any supportive policies targeting the sector).
- The modelling also suggests that there is a preference for generating on-site hydrogen rather than pushing for larger centralised production facilities. This is because the high cost of distributing hydrogen is higher than the assumed benefits of operating at scale. This is a sensitive conclusion and depends on the scale advantages expected in the capital costs of large electrolyser projects (for which there is a lack of reliable data) and electricity price advantages at scale. Small changes in these assumptions affect the conclusion on the relative merit of on-site vs. large centralised electrolysers. What is clear is that there are no clear advantage for large scale electrolysis over small on-site plant once they reach beyond the 1MW+ scale.

Conclusions (3/4) – the non-transport end uses will require best case electrolysers KPIs and a supportive regulatory environment

Non-transport uses

- The non-transport use cases (gas injection and industrial hydrogen replacement) suffer from a much lower cost counterfactual, which is dominated by the cost of natural gas. As a result, the electrolyser options struggle to compete for all but the best case KPIs for capital cost and efficiency.
- In many cases, even with best case costs and efficiencies a considerable carbon price is required to bridge the gap between the electrolyser derived hydrogen and the counterfactual.
- Only in the low electricity price regimes with favourable balancing systems (especially Germany) are these carbon prices below the projected 2030 carbon price, suggesting that electrolysers could begin to compete in these markets in 2030 if the technology develops to its lowest cost and highest performance points.
- In other markets, changes in the electricity market regulatory regime and/or a high carbon price will be needed alongside best case KPIs for the electrolysers to compete for non-transport uses.

Upsides for hydrogen price from electrolysers

- There are two plausible cases where electrolytic hydrogen costs could drop considerably below those modelled here. Hydrogen price reductions over 20% could be achieved, which are sufficient to make the non-transport cases viable with best case KPIs (and even with central KPIs in Germany):
    1) increased balancing services – operating either side of nominal 50% load factors (for low cost electrolysers) could double balancing services per kg of hydrogen generated and in so doing considerably reduce the effective cost of hydrogen
    2) Increased volatility of electricity prices increases the value of a strategy of controlling electrolyser output to take advantage of periods of low cost electricity

Both scenarios merit further analysis.

Conclusions (4/4) – Electricity to electricity storage as a stand alone use case appears challenging given the system efficiency

Electricity to electricity storage

- Using hydrogen to store and then regenerate electricity incurs a high round trip efficiency penalty.
- These losses are such that in a world with today's electricity price volatility, it is not possible to envisage a competitive scenario for using hydrogen to store electricity on a grid scale (note the analysis does not include off-grid applications for storage)
- Even in a highly volatile world with large swings in electricity price, it still appears that an additional value would be required to incentivise the storage and regeneration of electricity using hydrogen. I.e. arbitraging the market volatility using hydrogen as an electricity store is not enough on its own and a new "storage" tariff would be needed.

CO_2 considerations

- At today's grid mix carbon intensities, the carbon intensity of electrolytic hydrogen is considerably higher than that derived from SMR derived hydrogen.
- As grids decarbonise, this conclusion is reversed so that by 2030 (according to national projections), electrolysers using grid mix electricity have a lower carbon intensity than hydrogen from natural gas.
- Before then, mechanisms to justify a lower carbon status for electrolytic hydrogen will be required. These would benefit from further analysis and development of appropriate certification systems. They include:
  - Use of green certificates to create a contractual link between electricity generated at a low carbon source and the electrolyser
  - Direct coupling of renewable generators to electrolysers
  - Better accounting for the CO_2 benefits of providing grid balancing services using electrolysers instead of other more carbon intensive mechanisms (such as operating a thermal plant away from its peak efficiency).

- Introduction to the techno economic model and data
- Results of the techno-economic modelling
- Target setting: sensitivity of the hydrogen price to the key parameters
- Conclusions
- Appendices
  - Energy markets and data
  - Electrolyser operating modes

Appendix I - Energy markets and data - subtopics

- Energy markets and data
  - Country choice
  - Data sources
  - 2012 industrial electricity and gas prices
  - Energy price projections
  - Impact of projections on electricity and gas prices – 2030
  - Carbon prices

Market structure of the selected countries

Country	United Kingdom	Germany	Spain	Poland	Finland
Electricity generation mix[1]	46% gas 28% coal 16% nuclear 8% renewables	14% gas 42% coal 22% nuclear 17% renewables	36% gas 12% coal 17% nuclear 26% renewables	4% gas 87% coal 7% renewables 2% petroleum products	15% gas 28% nuclear 30% renewables 26% solid fuels 1% other
2020 RES target[1]	15%	18%	20%	15%	38%
TWh pa[1]	400	619	303	158	85
Market structure	Liberalised, separation of generation and supply, unregulated prices to all customers	Fully liberalised, four vertically integrated suppliers control 50% of market	Deregulated, but relatively concentrated	Some unbundling, lots of power still sold within vertically integrated companies.	Largely unbundled, unregulated prices to all customers
Price to industrial customers[2] (excluding VAT)	€81/MWh (based on UK data sources)	€51/MWh (based on DE data sources)	€72/MWh (based on ES data sources)	€74/MWh (based on Eurostat data)	€62/MWh (based on Eurostat data)

1. Source: EU Energy in figures, statistical pocketbook 2012. 2. Sources as per slide 10

Data sources

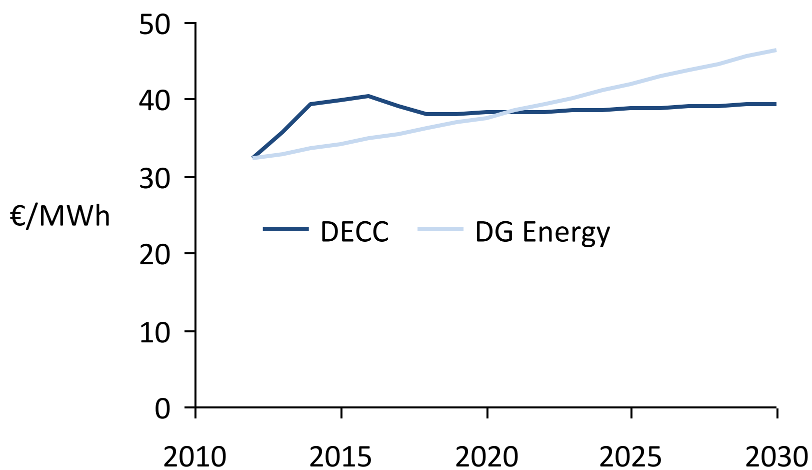
	United Kingdom	Germany	Spain	Poland	Finland
2012 spot market data	APX	EEX	OMIE/OMEL	TGE	Elspot
Tariff structure for large consumers	Network charges: UK DNOs Levies/taxes: DECC Other charges: confidential project data	Network charges: Eurostat. Taxes and levies: BDEW, Exemptions/reductions: national legislation	Network charges: national data Taxes: Eurostat	Network charges and taxes from Eurostat	Network charges and taxes from Eurostat
Projections for future prices	DG ENER Energy Roadmap to 2050, Impact Assessment, 2011. Current policy initiatives scenario				
Projection of future volatility	Decarbonising the GB power sector, Redpoint report to the UK Committee on Climate Change, 2009	No public price duration or frequency duration information found			
Current demand and prices for balancing services	National Grid	Ampiron, Tennet TSO, 50 Hertz, Transnet BW, and Regelleistung	N/A	N/A	N/A
Future demand and prices for balancing services	National Grid Operating the Networks in 2020	No public projections found	N/A	N/A	N/A

Energy price projections vary widely between forecasters – hence this needs to be understood as a key sensitivity in the analysis

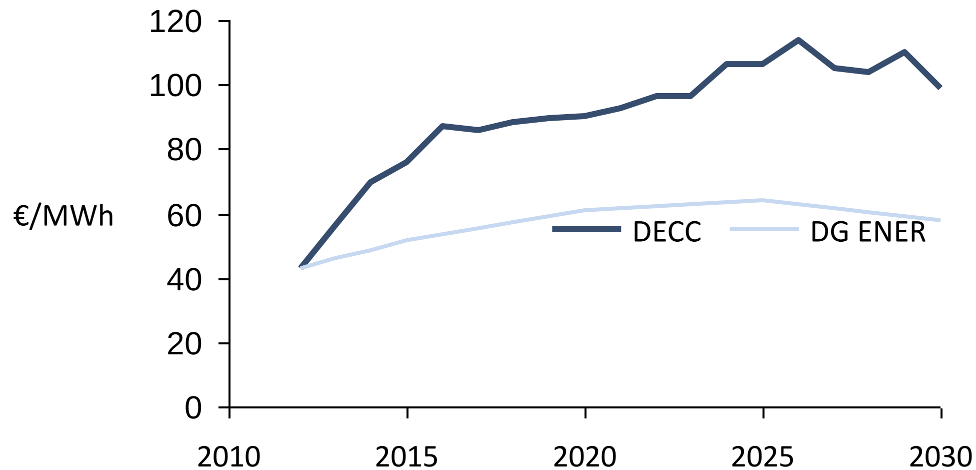
Energy prices in 2030

- There are different views on how energy prices will evolve over the coming years.
- The graphs below show two different projections for industrial electricity and gas prices.
- Energy price projections from DECC are shown in dark blue. DECC project a c. 100% increase in electricity prices between now and 2030, and relatively flat gas prices.
- One particular energy price projection by DG Energy (the current policy initiatives scenario) is shown in light blue. This projects a c. 15% increase in electricity prices between now and 2030, and a c. 50% increase in gas prices.
- Given the critical dependence of the price of natural gas versus electricity on the relative attractiveness of natural gas or electricity derived hydrogen production, it is important to recognise that this is a key sensitivity in the analysis.

Industrial gas price projections



Industrial electricity price projections

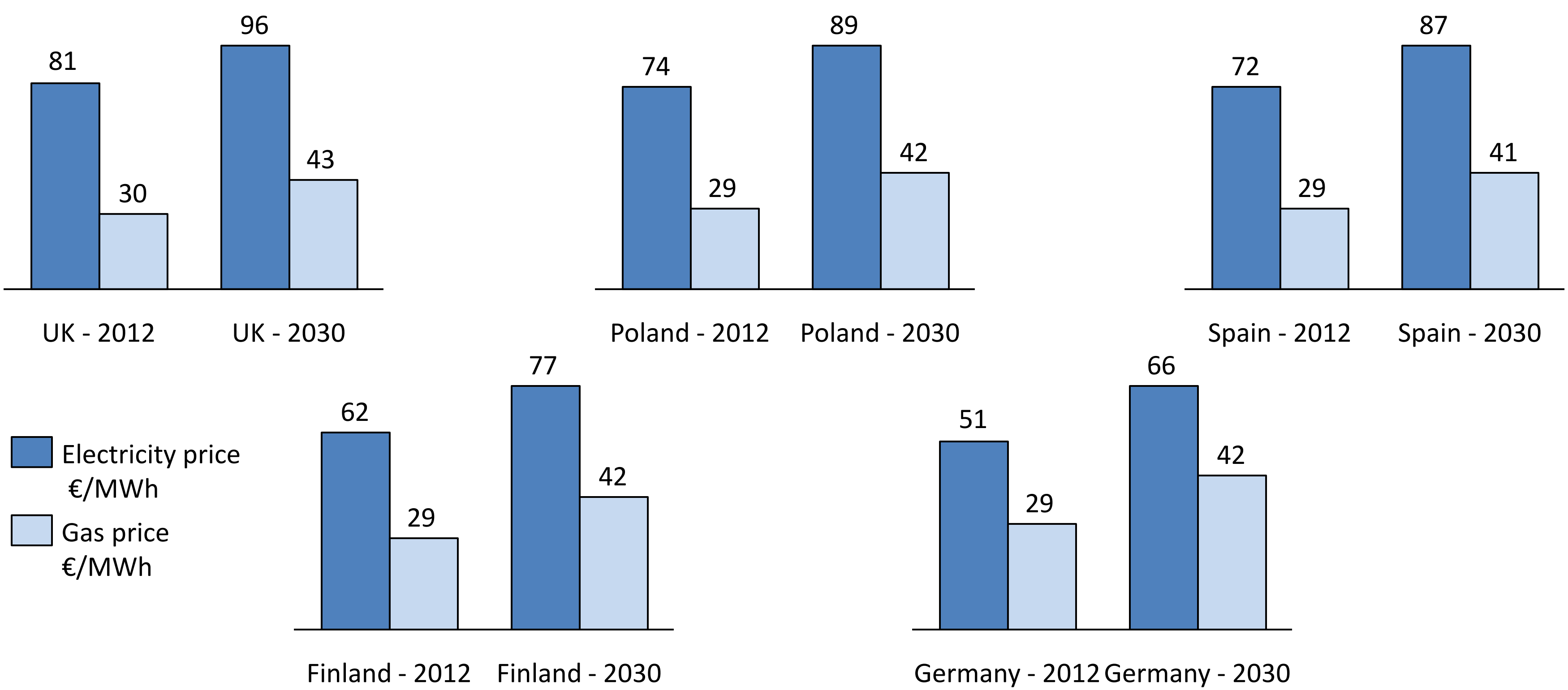


Energy price assumptions used are based on DG ENER forecasts for all countries

Energy prices in 2030

- In order to ensure consistency across the analysis, we have used DG ENER forecasts of electricity and gas price in each market to scale today's energy prices in each market (based on spot market data). 2012 values for network costs, taxes, levies and any other charges are then added in.
- The resulting energy price forecasts for larger industrial customers are illustrated below.

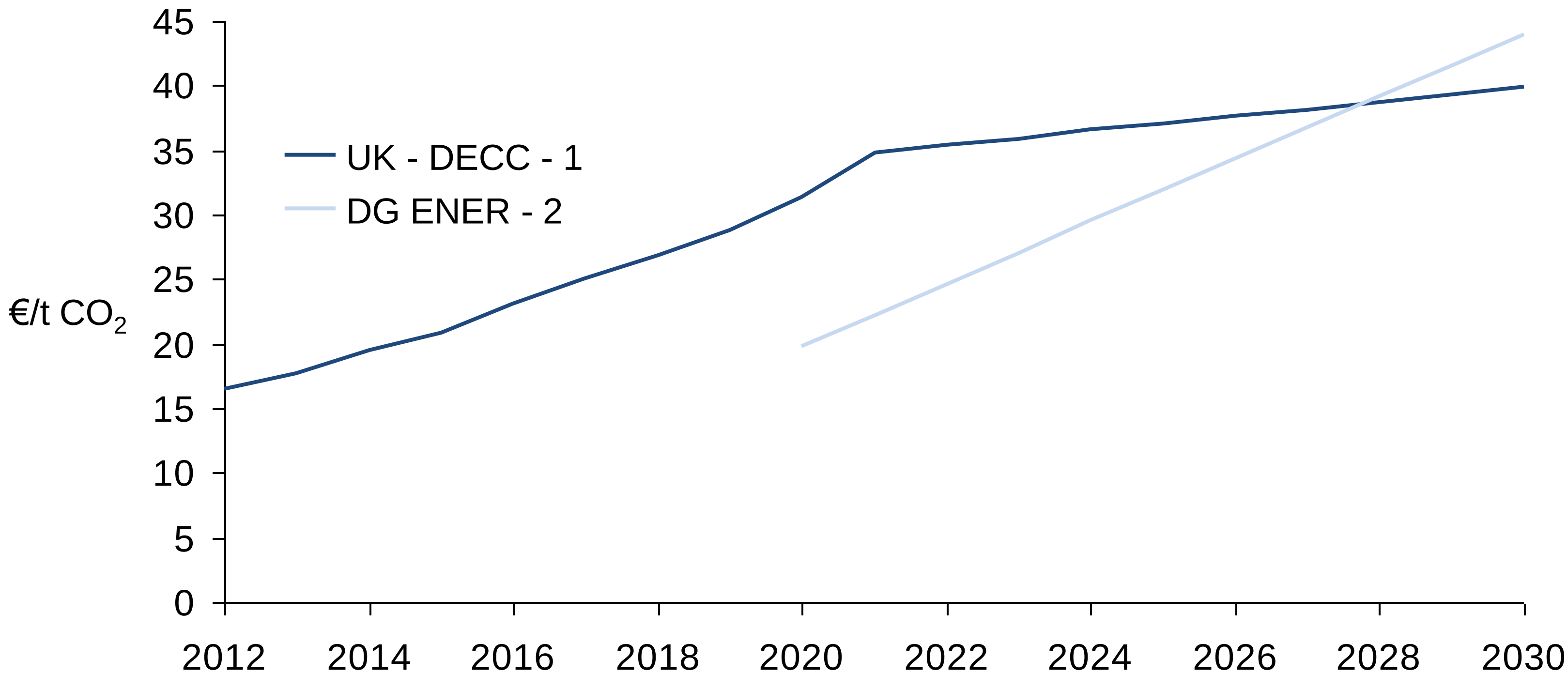
Electricity and gas prices in 2012 and forecasts for 2030, €/MWh



Carbon prices are not included in the modelling, instead the value of carbon to compete with the counterfactual is recorded

Carbon prices

- Carbon prices are calculated within the modelling to understand the required carbon price to compete with a counterfactual.
- These can then be compared with projections of the carbon price to understand whether the carbon prices envisaged are comparable to that required to allow competition with the counterfactual
- The carbon pricing assumptions used for this comparison are shown below:



1 – Carbon values used in DECC modelling, October 2011. 2 – DG ENER Energy Roadmap to 2050, reference scenario carbon price projections. 3 – EU Energy Trends to 2030 DE grid emissions of 0.190kg CO_2/kWh in 2030. 4 – Urban buses – alternative powertrains for Europe. 5 – Natural gas emissions of 0.203kgCO_2/kWh from Defra.

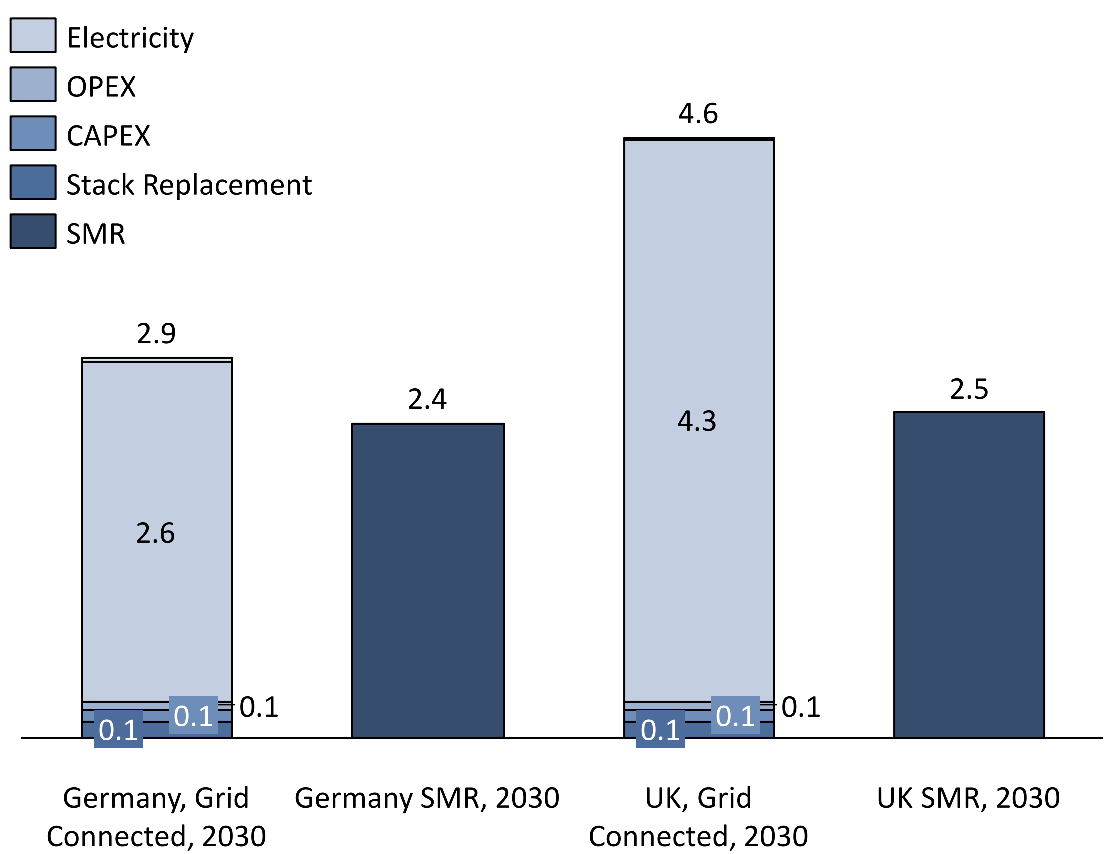
Appendix II - Electrolyser operating modes - subtopics

- Electrolyser operating modes
    - 100% load factor
    - Price minimisation
    - Balancing services
    - Accessing low cost electricity via a renewable generator

The simplest electrolyser operating mode is to maximise use of the system by achieving a 100% load factor

2030

Hydrogen cost at the electrolyser, €/Kg



PEM & Best Case KPIs

Even though this strategy aims to maximum use of the equipment, and hence reduce the capital cost per unit of hydrogen produced, the electricity costs dominate.

This highlights the value of looking to reduce electricity prices or gain additional revenue by offering services to the grid.

Strategies to access low cost electricity

It is clear that electrolysers need to access low cost electricity in order to become close to competitive with SMR produced hydrogen. We have therefore investigated a number of strategies for reducing electricity costs/increasing revenues:

Price minimisation - A threshold electricity price is set, above which the electrolyser will be switched off. This aims to keep costs to a minimum.

Response and reserve - Electrolyser is operated to access additional revenues by providing response and reserve services. In this scenario the electrolyser is always on, unless the system operator requests it to be turned off.

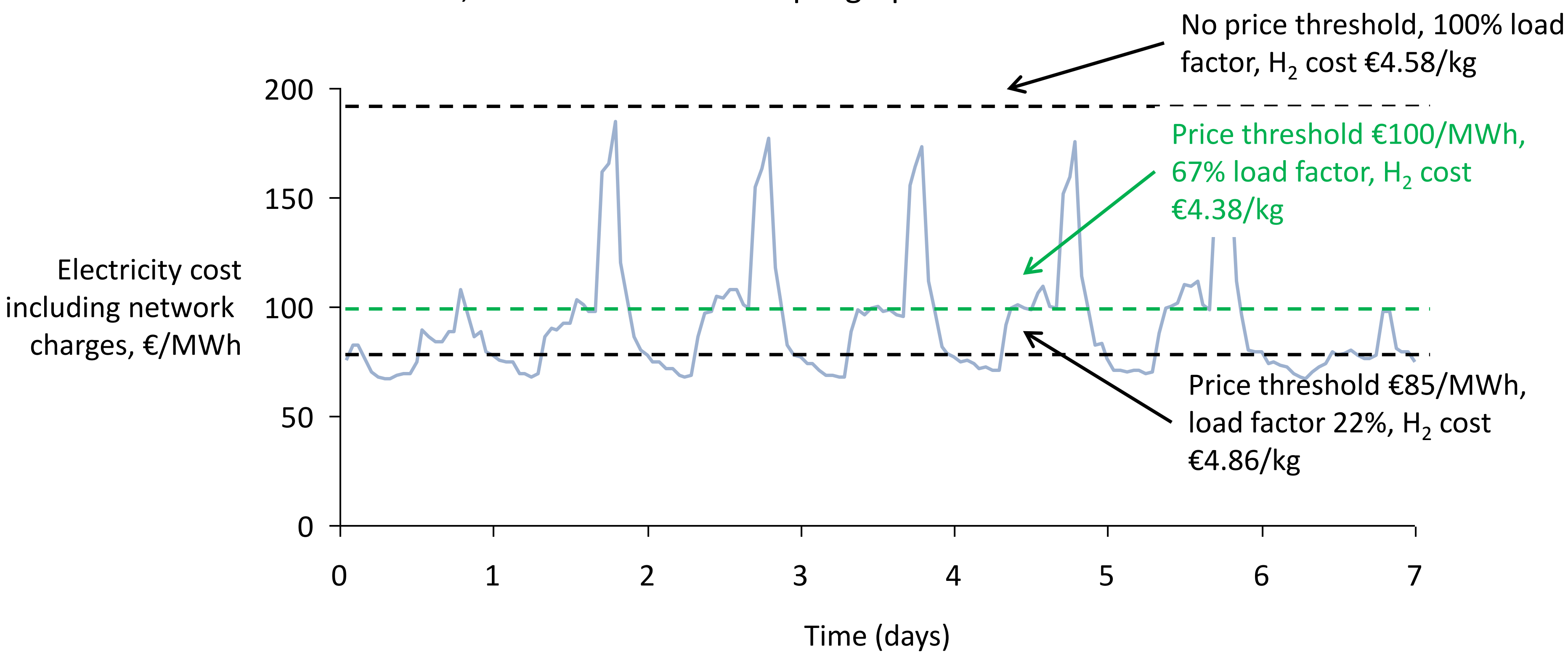
Grid reinforcement - Electrolysers located in strategic places for the electricity network can avoid the need for expensive, and underutilised transmission and distribution upgrades required to accommodate peak output of intermittent generation.

Access to low cost electricity which would not otherwise be able to connect to the grid – e.g. where transmission capacity means they would face constraints, or specific locations where the connection costs could be high, and timescales for connection could be long.

We have also considered combinations of the first three strategies above

An optimisation is required for the price minimisation strategy

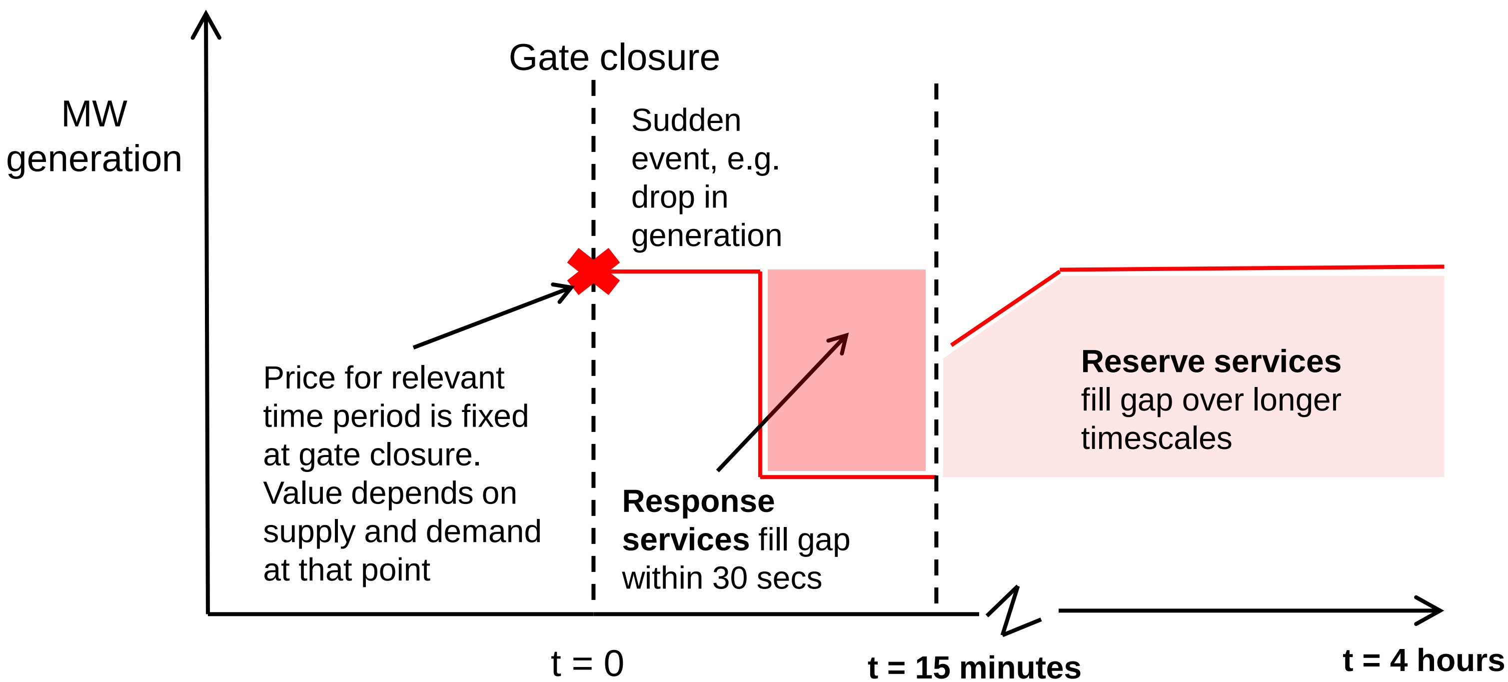
- This strategy looks to take advantage of variations in the spot electricity price, as well as variations in the network charges depending on the time of day.
- Switching the electrolyser off at times when the electricity price is above a certain price reduces costs. However this also reduces the load factor, increasing the amount of capital cost which needs to be included in the cost of each kg of hydrogen. An optimisation is therefore undertaken, as shown in the example graph below.



Electrolysers can access additional revenues by offering balancing services

- Changes in supply and demand before "gate closure" for the delivery hour in question are managed by the system operator and result in the price for the hour in question.
- **Balancing services** are the services procured by the system operator to manage changes in supply and demand following gate closure. The services vary by the timescale of response , and by duration. Terminology varies between UK and the rest of Europe, and therefore we define common timescales and terminology below – response and reserve services.

Schematic of timescales over which reserve and response services help to balance supply and demand following gate closure



Overview of the potential for electrolysers to offer balancing services in the five countries studied

	United Kingdom	Germany	Finland	Spain and Poland
Type of service electrolysers can offer	Response (Frequency control by demand management) or reserve (Short-term operating reserve)	Reserve (secondary control reserve or tertiary control reserve)	Interruptible load contracts	Electrolysers cannot compete in the balancing services market
Service selected for modelling	Reserve for maximum available hours (c. 50% of the year), and response outside of these hours	Secondary control reserve, as value is higher than for tertiary control reserve	Not modelled as no price or service data is available	
Value of service in 2012	Reserve: Availability: €11/MWh[1] Utilisation: €523/MW/hour[2] Response: Utilisation: €244/MW/hour[1]	Reserve[3]: Availability: €3.8/MWh Utilisation: €187/MW/hour		
Future value of services	Expected to increase[2]	No data available to support increasing value		
Modelling assumption: Largest capacity a single provider can offer	Largest single provider currently offers 30 MW. Model assumes the limit is double this level – i.e. 60 MW in a reserve market of 2.3 GW	UK data and assumption is scaled to German market size, so that maximum capacity that can be offered is 55 MW		

Sources:

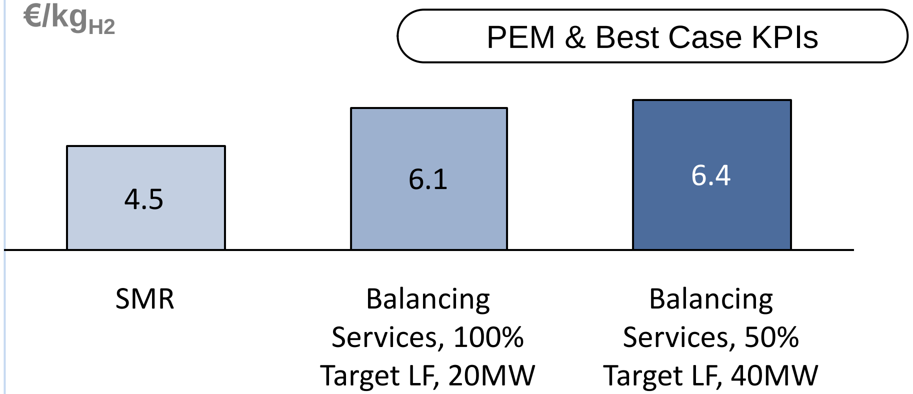
1- historical data from National Grid End of Year Reports . 2 – National Grid “Operating the Electricity Transmission Network in 2020”, 2011. 3 – annual average data is not available, only daily data can be downloaded, and therefore values are based on averages from selected days in 2012. Data sources Ampiron, Tennet TSO, 50 Hertz, Transnet BW, and Regelleistung

Factors affecting price 2 – Electrolyser operating mode could increase the balancing values considerably for the transport case

Hydrogen cost at the nozzle[1], €/Kg

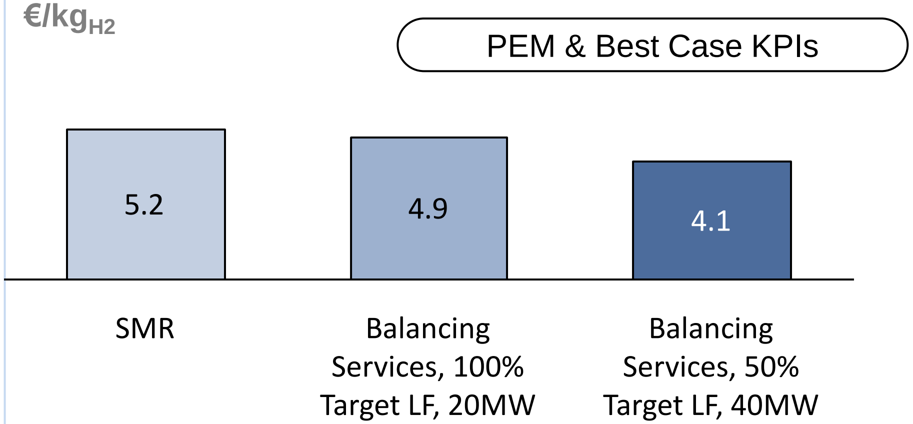
Case 1d, Germany, 2012

€/kg$_{H2}$



Case 1d, Germany, 2030

€/kg$_{H2}$



Balancing services limited to a maximum of 60MW per Water Electrolyser.

Context and emerging conclusions

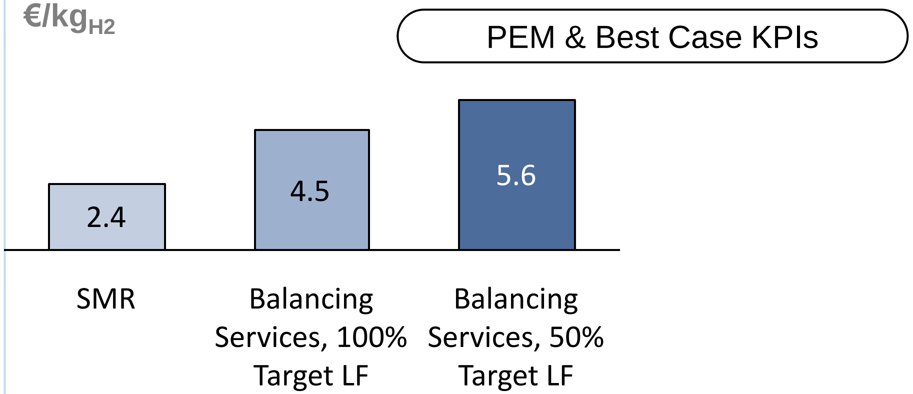
- The following analysis is based on a PEM water electrolyser with 10% lower energy input requirement at 50% load factor.
- The system is sized to satisfy all demand required by the use case, accounting for 50% load factor.
- With 2012 performance and costs, no benefits are expected from operating at part load, even if lower energy input at part load is witnessed.
- Given 2030 performance and costs (reduced energy input per kg hydrogen at rated power, lower capex), the cost of hydrogen can be reduced by up to €0.9/kg$_{H2}$.
- A combination of reduction in capex, improved energy input per kg of hydrogen and an optimised operating strategy is likely to far outweigh the forecast increases in electricity price.
- Balancing services provides benefits of €1.3/kg$_{H2}$ and €0.6/kg$_{H2}$ at 50% and 100% target load factors, respectively.

Factors affecting price 2 – Electrolyser operating mode could increase the balancing values and help support industrial uses

Hydrogen cost at the nozzle[1], €/Kg

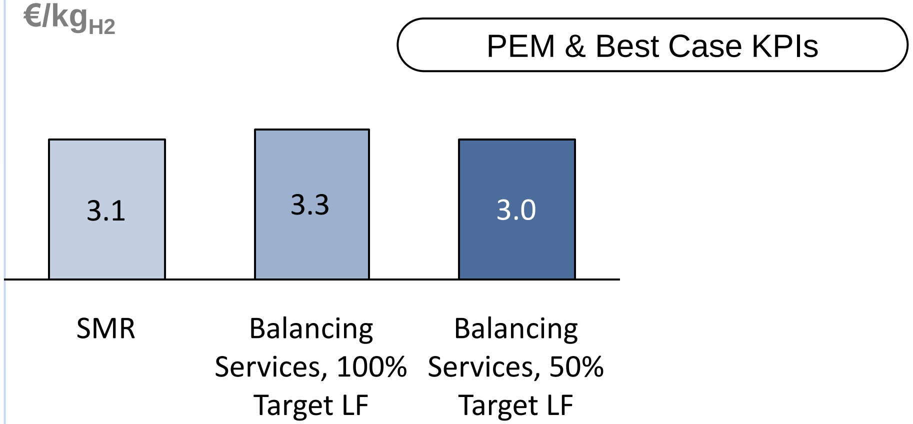
Case 2c, Germany, 2012

€/kg$_{H2}$



Case 2c, Germany, 2030

€/kg$_{H2}$



Balancing services limited to a maximum of 60MW per Water Electrolyser.

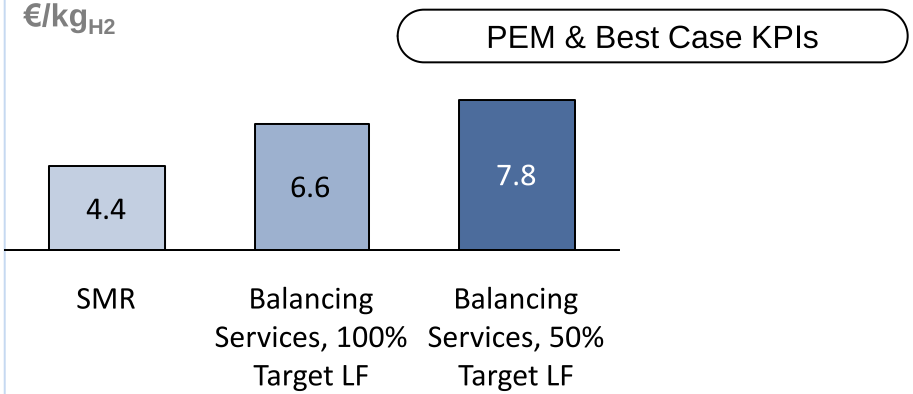
Context and emerging conclusions

- With 2012 performance and costs, no benefits are expected from operating at part load, even if lower energy input at part load is witnessed.
- By 2030, in industrial applications, operating at a 50% load factor can reduce the cost of hydrogen from water electrolysers by up to €0.3/kg$_{H2}$ when compared to a 100% load factor balancing services strategy, allowing it to be competitive with the SMR counterfactual.
- System is modelled to model only ±60MW of balancing services, although it is capable of offering ±250MW. Hence, balancing services provides benefits of € 0.31/kg$_{H2}$ at 50% load factor and €0.14/kg$_{H2}$ at 100% load factor.

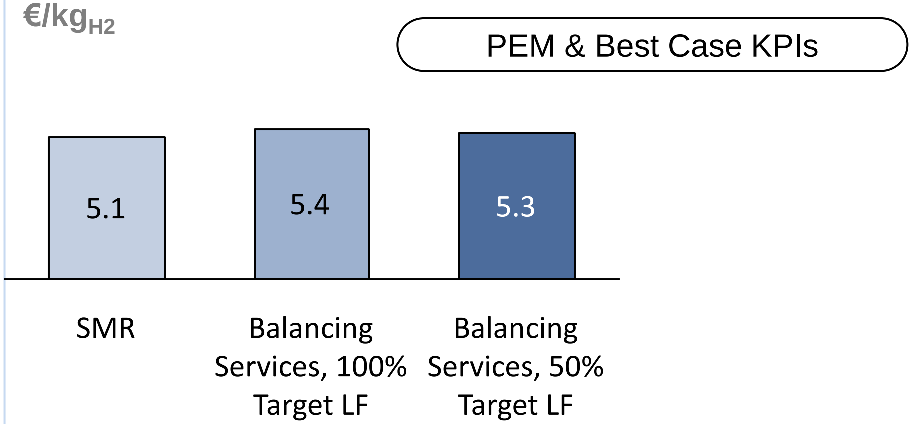
Factors affecting price 2 – Electrolyser operating mode could increase the balancing values

Hydrogen cost at the nozzle[1], €/Kg

Case 3c, Germany, 2012
€/kg_{H2}



Case 3c, Germany, 2030
€/kg_{H2}



Balancing services limited to a maximum of 60MW per Water Electrolyser.

Context and emerging conclusions

- Given 2030 performance and costs (reduced energy input per kg hydrogen at rated power, lower capex), operating at 50% load factor can reduce the cost of hydrogen from water electrolysers by up to €0.08/$kg_{H2.}$
- This is not sufficient to alter the competition with SMR derived hydrogen for this application.
- The benefits of operating at 50% load factor is significantly limited by the amount of balancing services offered by a single water electrolyser unit: only $\pm$60MW, although it is capable of offering $\pm$1000MW. This reduces the benefits of balancing services per kg of H_2 produced to a relatively small €0.08/$kg_{H2.}$

Summary of the strategies for reducing grid electricity costs

United Kingdom, 2012 and 2030

Price minimisation

- Electrolyser runs during phases of low electricity price (spot price plus network charges)
- Small effect in 2012, may increase if electricity price increases and if volatility increases
- If effect increases then electrolyser load factor will decrease, but an optimisation can be undertaken.

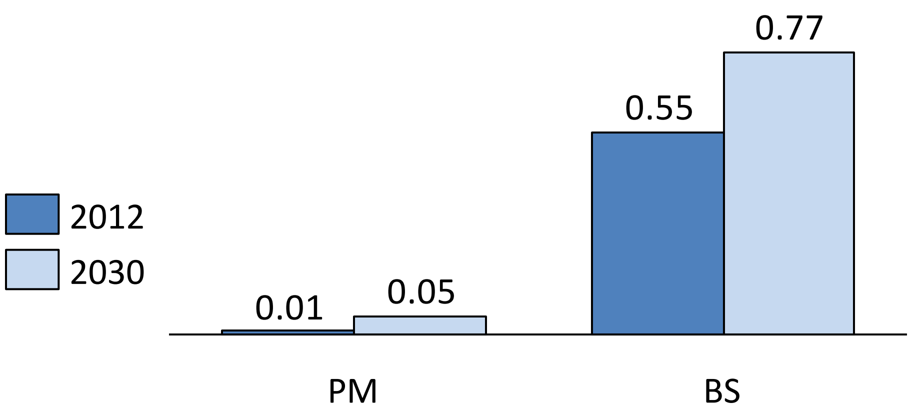
PM

VS

BS

Balancing services

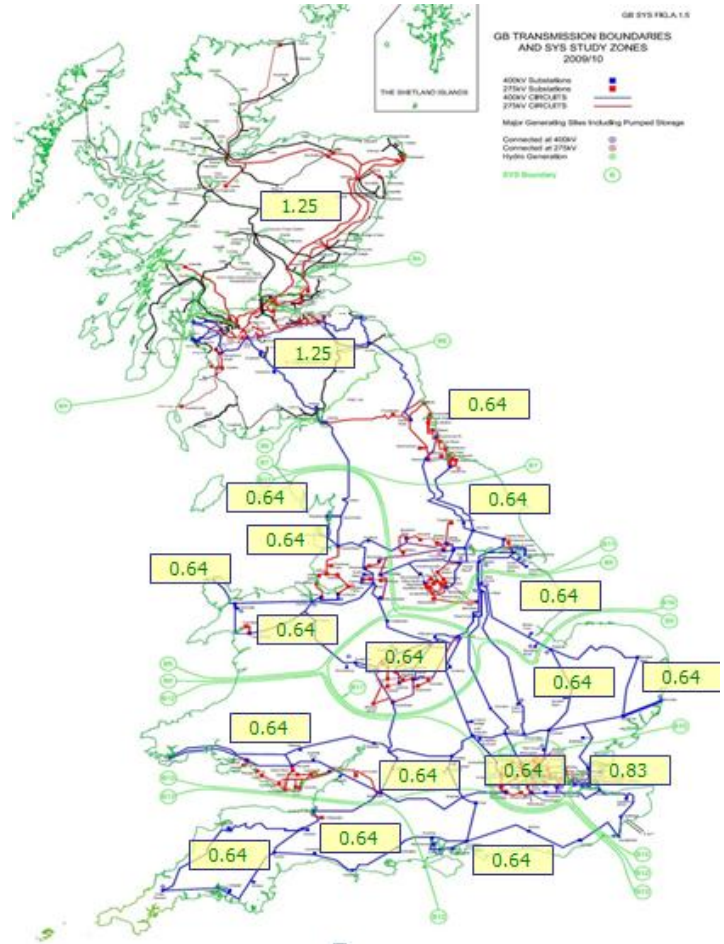
- Electrolyser runs all the time in order to offer negative response and reserve services – cannot be additive with price minimisation
- Effect in 2012 is significant, and may increase to 2020 if demand for balancing services increases.



Benefit, in €/kg, of the 2 strategies. Based on alkaline technology, best case KPIs for 2012 and for 2030. No end use case is assumed

It may be possible to access low cost electricity which would not otherwise be able to connect to the grid

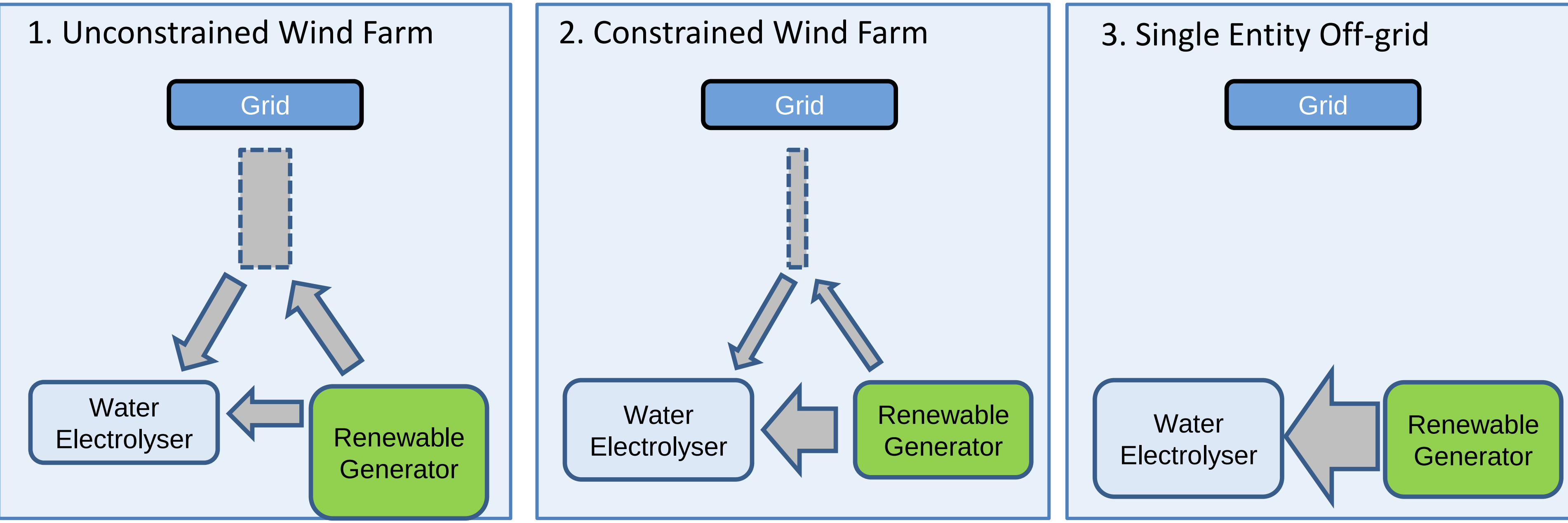
- Many countries are facing significant constraints in terms of transmission and distribution capacity. As an example, in the UK, the bulk of generation is in the north, and the bulk of demand in the south. Hence there is a transmission constraint, and it is more difficult, and expensive, to connect new generation in the north than in the south.
- Renewable generators are one form of generation affected by this situation. Connections in the north, in Scotland in particular, are expensive, and new assets built to connect renewable generation have low utilisation factors.
- Renewable generators therefore face constraints, and this section of the analysis considers whether electrolysers can help by using the energy, reducing connection costs and/or use of system costs for generators.
- Wind farms are also experiencing curtailment, when peak wind output plus inflexible generation is greater than demand. This analysis does not consider the impact of using electrolysers to reduce curtailments.



Map of the UK showing transmission constraints, from the National Grid ELSI model. Figures are for the value of firm access to the national market, £/kW/year – the larger the number, the higher the transmission constraint.

System diagram of the three scenarios considered – electrolyser connected to renewables and to grid

We have modelled whether an electrolyser can offer a service in three key scenarios:



Scenario	1	2	3
Distribution Line Capacity (MW)	10	5	0
Renewable Generator Size (MW)	10	10	10
Water Electrolyser Size (MW)	1	5	10

Source: 1 based on Element Energy modelled data for a wind farm in Scotland, with 48% load factor, and wholesale prices as of 2012

Inputs into the modelling to analyse hydrogen costs for an electrolyser linked to a renewable generator: a UK wind farm

Wind Farm assumptions[1]:

- CAPEX, including pre-development costs: £1,600/kW (€1,956/kW, assuming EUR to GBP Exchange Rate for 2012 of 1.2227)
- Fixed OPEX: £37,000/MW/yr (€45,240/MW/yr), insurance: £3,000/MW/yr (€3,668/MW/yr), variable OPEX: £5/MWh/yr (€6.11/MWh/yr), Connection and DUoS: Equivalent to €3.93/MWh
- Discount Rate: 7% discount rate
- Lifetime: 20 years

Wind farm dataset

- Hourly wind dataset comes from an onshore wind farm with a load factor of 31%, and we have filled gaps in this dataset using synthetic data.

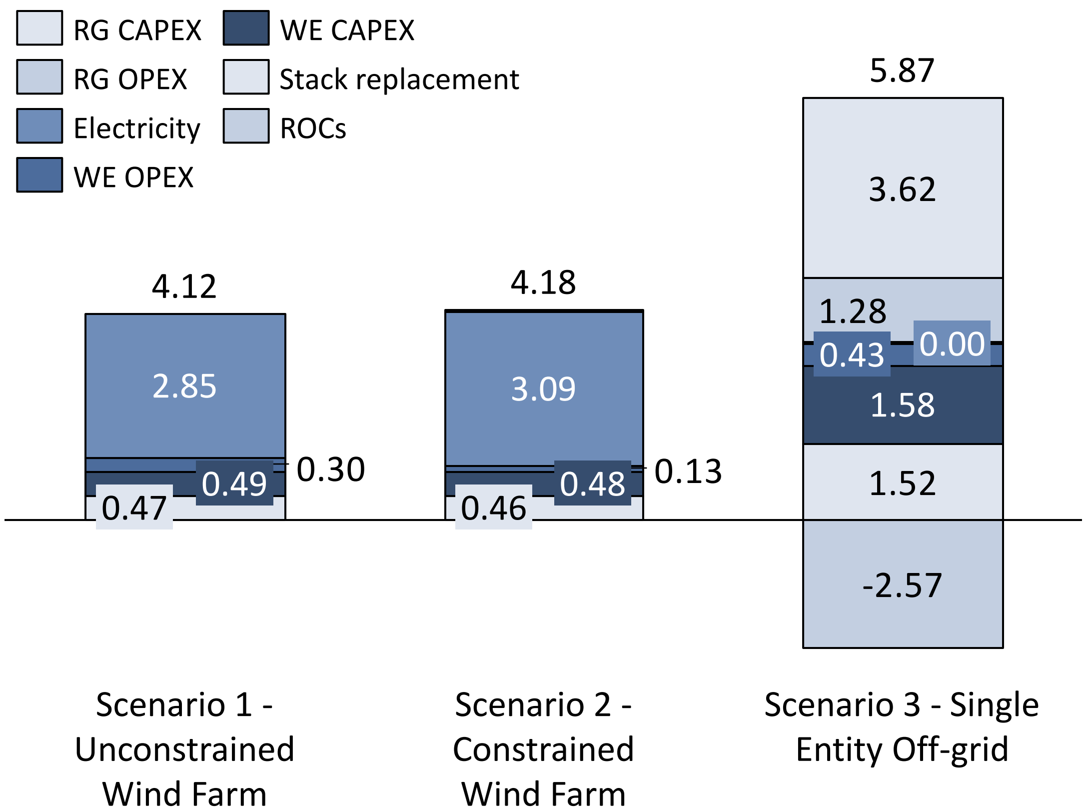
Renewable subsidy

- This analysis assumes that the wind farm continues to receive the subsidy – the Renewable Obligation Certificates – for energy which it exports to the electrolyser. The value of the ROC in 2012 is c. €51/MWh.

Source: [1]DECC Onshore Wind Call for Evidence – Annex D, Table D2

Hydrogen costs are the lowest when the water electrolyser is connected to an unconstrained wind farm, and can negotiate cheaper energy from that wind farm

United Kingdom,
2012,
31% load factor on wind farm



Scenario	1	2	3
Distribution Line Capacity	10MW	5MW	0 MW
Renewable Generator Size	10MW	10MW	10MW
Water Electrolyser Size	1MW	5MW	10MW
Load Factor	97%	98%	31%

Graph to show the total hydrogen cost (€/kg), and components for hydrogen cost

Alkaline, best case KPIs

Connecting to a grid and an unconstrained wind farm will result in a lower hydrogen cost than being only on the grid. The water electrolyser benefits by negotiating a electricity price slightly above the spot price (but without incurring DUoS and TUoS charges). The wind farm benefits by gaining a slightly higher electricity price, avoiding some use of system charges, and retaining the renewable subsidy – the ROCs. All 3 scenarios are heavily dependent on this subsidy remaining in place, and being applicable to the energy exported to the electrolyser.

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