"Assessment of the Potential, the Actors and Relevant Business Cases for Large Scale and Long Term Storage of Renewable Electricity by Hydrogen Underground Storage in Europe"

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European context and the need for electricity storage

The European Union has set itself ambitious climate protection targets which call for a transformation and decarbonisation of the energy system in Europe. The targets for 2020 are a 20% reduction of greenhouse gas (GHG) emissions, a 20% share of renewable energy sources (RES) in the energy mix and a 20% reduction in primary energy use. The EU's long-term strategy until 2050 envisages an 80% to 95% reduction of GHG emissions compared to 1990 levels.

Achieving these demanding targets will require a fundamentally different energy system, with renewables such as onshore and offshore wind and photovoltaic (PV) energy playing a crucial role in the electricity generation mix. Unlike the energy sources used in conventional power plants, these renewable sources are not dispatchable and they fluctuate over time, resulting in intermittent feed-in of electricity into the grid.

As the European energy system decarbonises, the greater reliance on intermittent renewable energy sources poses a number of challenges concerning their large-scale system integration: most importantly, this includes temporary mismatches between supply and demand as well as growing strains on the grid. This will require a mix of different solutions to maintain grid stability. Generally considered solutions are flexible fossil-based generation, grid expansion, demand-side management of the structural final demand for electricity, electricity storage (including conversion to other energy carriers such as hydrogen), flexible electrification of heat demand with hybrid heating systems and curtailment of surplus intermittent generation capacity.

The specific characteristics of the energy systems and national energy policy approaches vary significantly across European countries. This will be reflected by differences regarding the challenges of integrating renewables from a capacity and regulatory perspective. It will also affect the possibility for application of any particular solution, and the mix of flexibility measures to be applied. In any case, ongoing decarbonisation and increasing reliance on fluctuating renewable energy sources are expected to create an increased demand for energy storage technologies.

In general, the need for electricity storage is driven by the extent to which the electricity system is subject to (temporary) mismatches between supply and demand, which may also result in more volatile electricity prices. In those cases, storage can serve as a buffer, which absorbs surplus electricity generated from renewable energy sources at times when supply exceeds demand, and can provide additional capacity in deficit situations, when the volatile generation is not sufficient to cover the electricity demand. This creates opportunities for electricity time shift and conversion to other energy carriers.

Key parameters which determine supply-demand mismatches and the resulting need for storage include, on the one hand, the amount of installed intermittent renewable generation capacity (onshore and offshore wind, PV), their specific generation characteristics (i.e. the wind speed and solar irradiance profiles), and on the other hand the electricity demand profile.

Additionally, the geographical distribution of generation and consumption centres, and the availability of interconnecting grid capacity have an impact on the demand for electricity storage. The type of storage solutions and the need for ancillary services, like frequency control, will also differ depending on the voltage level at which renewable electricity is fed into the grid, i.e. at the low-voltage local distribution grid, or the high-voltage transmission grid.

The case for underground storage of hydrogen

The electrolysis of water to produce hydrogen in combination with hydrogen underground storage, where geologically feasible and acceptable to the public, is a readily available and technically feasible option for TWh-scale storage of fluctuating renewable electricity over extended periods of time, in the order of weeks up to months. As a result, there is a rapidly growing interest in the role electrolytically produced hydrogen could play for the system integration of intermittent renewables.

The unique aspect of hydrogen as energy storage medium is its use as ‘universal energy vector’, i.e. its versatility with regard to a range of end-use applications. It can be used for re-electrification, in which case it can be considered as ‘classical’ electricity storage option; but it can also be used in other sectors beyond the electricity system. Examples are the use as vehicle fuel for fuel cell electric vehicles (FCEV); the use as feedstock and even as heating fuel in industry, such as the chemical and petrochemical industry, and the steel industry; and for the greening of natural gas by admixing hydrogen into the natural gas grid (within technically acceptable limits).

Against the background of the European policy goals to significantly reduce greenhouse gas emissions by increasing the share of renewable energies in all energy sectors, there is an opportunity to leverage synergies between hydrogen as a storage medium and as a potentially ‘green’ fuel (e.g. from shared infrastructures), which enables the extensive deployment of intermittent renewables for applications other than typical electricity applications, most notably for mobility and industry.

The HyUnder project – objectives

Following this promising perspective, the objective of the **HyUnder** project was to assess the potential of hydrogen underground storage in Europe, taking geological and geographic factors into account, and to assess the feasibility of the business cases for conversion of renewable electricity into hydrogen in combination with large-scale underground storage. Although the European perspective is taken as starting point, the more detailed analyses in the project have been focussed particularly on the six European countries that were part of the project consortium, i.e. France (FR), Germany (DE), the Netherlands (NL), Romania (RO), Spain (ES) and the United Kingdom (UK).

Potential scale of the challenge – estimates for surplus electricity

It has been assumed that underground storage of hydrogen will initially be driven by an increase in "surplus" renewable electricity, being defined to occur when the difference between the electricity generation from renewable sources and conventional (must-run) power plants exceeds the overall electricity demand at any given point in time. Obviously, the moment, extent and location of the occurrence of this surplus depend on the speed, scale and type of renewable electricity rollout. Basic assessments of supply-demand mismatches, assuming an ideal "copper plate" electricity transmission system, and thus neglecting any possible network congestions, have been carried out on a national level to provide an indication of the maximum potential for storage of surplus. Locally or regionally, however, the occurrence of specific grid bottlenecks may increase the need for storage.

Longer term, with a very high (>60%) intermittent renewables share in the generation mix, an increasing need will develop to manage deficit situations as well, which requires electricity time shifts over extended periods for which hydrogen storage is a very feasible option. It is not at all clear today how solutions for such a future look like, but they could require significant use of hydrogen for re-electrification which would then not be available anymore for other uses.

It is important to note, though, that the scenarios have not taken into account other storage technologies, such as batteries, to be rolled out at large-scale, which would reduce any surplus available for conversion to hydrogen. Furthermore, the quantification of surplus also depends on future electricity demand patterns.

The following table provides a high-level overview of the country case study estimates on annual surplus electricity, and – assuming 100% conversion to hydrogen – the hydrogen supply potential for different applications as well as rough estimates of the potential number of caverns, installed electrolyser capacity and related investments.[1] The numbers are of hypothetical nature and meant only to give an indication about the potential market size for underground hydrogen storage and subsequent hydrogen applications; as other storage technologies and flexibility measures are being put in place, actual numbers are expected to be lower.

[1] Numbers in the table may slightly deviate from case study results, due to differences in assumptions. Data from the French case study are not included due to differences in the approach.

Table 1: Overview of country case study assessments

	Germany		Netherlands		Spain		UK		Romania	
	2025	2050	2025	2050	2025	2050	2025	2050	2025	2050
Surplus/a [TWh_{el}]	15	75	1	43	8	24	6	21	1	1
% intermittent RES of total electricity demand	30%	70%	31%	80%	32%	65%	42%	62%	13%	14%
% surplus of intermittent RES generation	9%	19%	3%	30%	3%	6%	8%	11%	9%	10%
H_2 equivalent [kt][2]	297	1,485	26	844	162	471	113	416	19	28
#FCEV (million)[3]	3.7	18.3	0.3	10.5	2.0	5.8	1.4	5.1	0.2	0.3
% passenger car fleet	8%	42%	4%	133%	8%	24%	4%	16%	5%	7%
% natural gas use	3%	15%	<1%	9%	2%	5%	1%	4%	<1%	<1%
% H_2 demand industry	8%	41%	3%	93%	24%	88%	16%	59%	16%	19%
No. of caverns[4]	15	74	1	43	8	24	6	21	1	1
Electrolyser capacity [GW][5]	5	25	0.5	14	3	8	2	7	0.3	0.5
Investment in electrolysis [B€][6]	5.6	18.7	0.5	10.7	3.0	6.0	2.1	5.2	0.3	0.3

In the above table, the annual estimated surplus electricity has been converted into the theoretical amount of hydrogen that could be made available for use in different applications (which are mutually exclusive in this case). In principle, end use options for this hydrogen are its use as a fuel in the potentially emerging mobility sector, selling it to industrial hydrogen customers, admixing it to the natural gas grid, and for re-electrification. In the case of industry this would largely be a substitution of today's fossil-based hydrogen production, whereas the other sectors would generate new demand and new markets for hydrogen. With FCEVs on the verge of market introduction, hydrogen as vehicle fuel currently receives considerable attention. However, in the short to medium term, potential hydrogen demand for mobility will be small compared to what could be fed into the natural gas grid or the existing substitution potential in the industry sector.

Clearly, the results illustrate that the estimated amount of surplus, if converted entirely to hydrogen, could fuel a significant number of FCEVs in some cases, such as in Germany. Also, it could replace a large share of industrial hydrogen which is currently produced mainly from natural gas. Building such an infrastructure of

[2] Assumes 100% conversion to hydrogen, 66% efficiency.

[3] Based on 0.54 kg H_2/100 km and 15,000 km per year.

[4] Assumes a mature-market cavern size of 500,000 m^3 with a hydrogen net storage capacity of 4 kt; based on simulations of charging/discharging patterns and the hydrogen inventory of the cavern, the required total storage capacity is roughly 20% of the total amount of hydrogen produced from surplus; cavern construction costs for brown field sites of 60 €/m^3, resulting in some 30 M€ (excl. cushion gas).

[5] Based on 2,000 full load hours.

[6] Assumes investment of 700 €/kW_{el} for electrolysis in 2025 and 500 €/kW_{el} in 2050.

integrated hydrogen electrolysis and underground storage sites would require significant multi-billion Euro investments, with installed electrolyser capacities of several GWs.

Site mapping of potential underground hydrogen storage sites

A geological mapping of European regions for underground storage of hydrogen has been performed in the project, considering both rock salt deposits and porous formations. A quantitative analysis has focused on the potential of salt deposits for the construction of caverns, as the preferred option for hydrogen storage, mainly for reasons of operational flexibility and lower levels of potential contamination of the hydrogen with in-situ materials; further research is required to assess the feasibility of hydrogen storage in porous formations, such as aquifers and depleted gas fields.[7]

Salt deposits suitable for cavern construction are unevenly distributed geographically and do not necessarily occur in those regions that have the highest potential for cavern storage; in this respect the northern parts of Germany and the Netherlands seem particularly promising.

The regional potential in the six countries for salt cavern construction is shown in Figure 1. The colour code reflects the storage potential of a certain area, defined as the presence of a salt structure or salt deposit suitable for the construction of hydrogen caverns. The map also shows that salt deposits are unevenly distributed throughout Europe and highlights the need for other hydrogen storage options where salt is absent (such as in porous formations).

[7] Through collaboration with supporting partners from industry as well as other regions within and outside of Europe the scope of the HyUnder project was broadened. Whereas the supporting partners from different industry sectors contributed specifically to the analysis of the individual six country case studies, supporting partners from Argentina and Denmark addressed further regional aspects of hydrogen underground storage. The ongoing activities to test the impact of hydrogen admixture to a depleted natural gas field in Patagonia enriched the discussion and highlighted the need to perform practical tests to get reliable results.

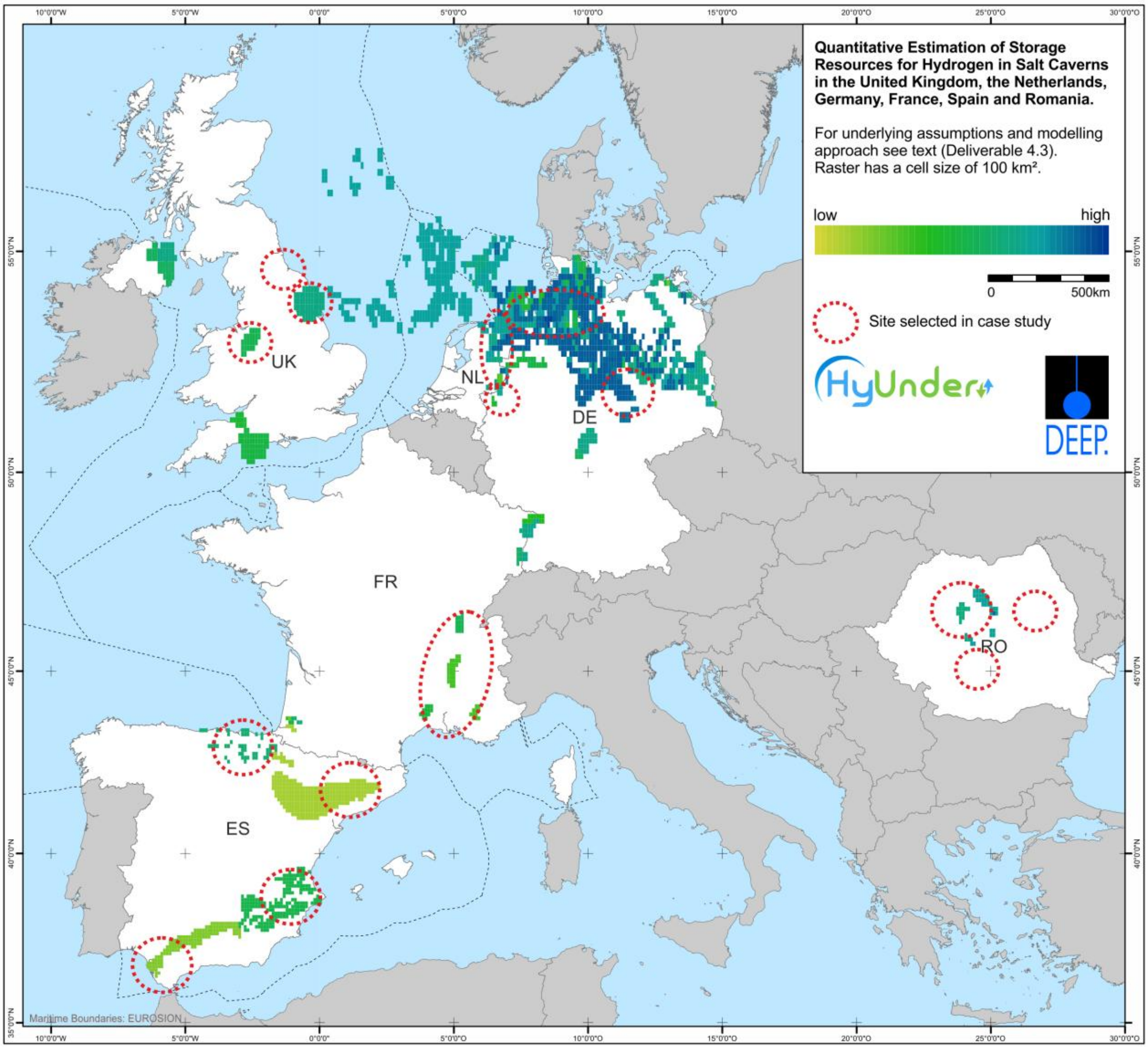

Figure 1: Geological mapping of salt formations and selected storage sites[8]

The geological conditions, i.e. the depth and thickness of the deposit, the nature and amount of insoluble rock components in the salt, and the structural style of the deposit are the main parameters to determine the feasibility of building a storage cavern.

Besides, other non-geological location factors have been taken into account in order to determine promising site locations. Most importantly, this may be the access to nearby brine processing facilities for salt or chlorine production, or brine disposal options (like the sea, where allowed). The availability of cheap electricity (e.g. by

[8] The assessment of the salt deposits was made based on an approach to design model caverns, on the available geological information and common cavern construction limitations. However, salt deposits in some locations were assessed directly by the case study participants, based on different parameters or with additional data available. Thus for the UK and Romania, sites have been selected for the case study assessment that show no significant potential based on the cavern model.

eliminating grid fees) as well as access to potential future hydrogen markets are other important considerations (see Figure 2). With respect to all considered factors, Germany, the Netherlands and the UK seem the most suitable countries for hydrogen storage in salt deposits.

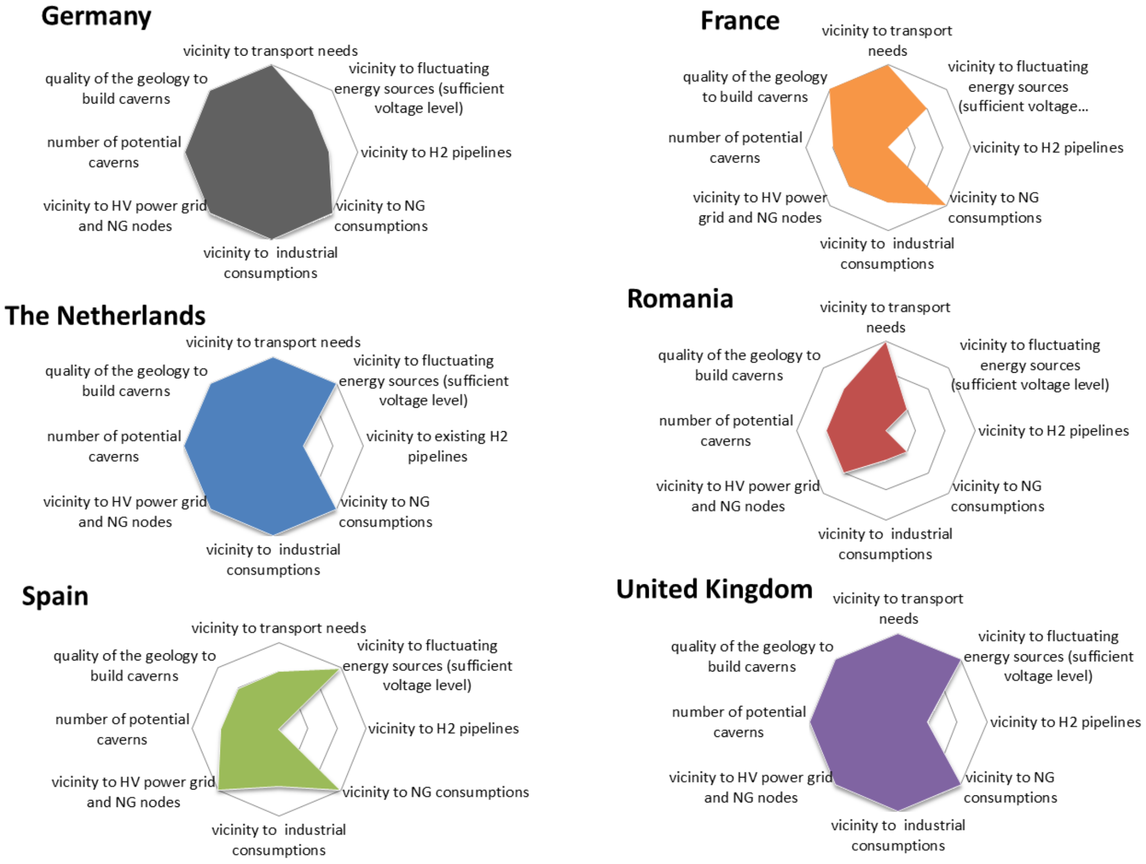

Figure 2: Qualitative assessment of the suitability of countries for hydrogen storage

Site selections will likely face a trade-off between different location factors, like the location's vicinity to renewable electricity hubs – especially when they are highly centralised such as for the landfall points of offshore wind energy – versus its vicinity to existing hydrogen infrastructure and hydrogen demand centres. Where possible, existing natural gas storage sites (initially) are preferred locations to start developing hydrogen caverns. There are a number of reasons for this, like lower expected development costs compared to green field sites because of existing leaching and brine processing infrastructure and lower exploration costs, possible extension of existing permits, and familiarity in the area with gas storage which might avoid, or help in overcoming potential issues regarding public acceptance.

Economic assessment of underground hydrogen storage and business cases

An integrated underground hydrogen storage facility for large-scale electricity storage typically consists of the following elements (see Figure 3):

- A water electrolysis unit for production of hydrogen
- A compressor unit for pressurization of the hydrogen for storage
- A salt cavern for storage of the hydrogen
- A purification section with drying unit and pressure swing absorption (PSA)

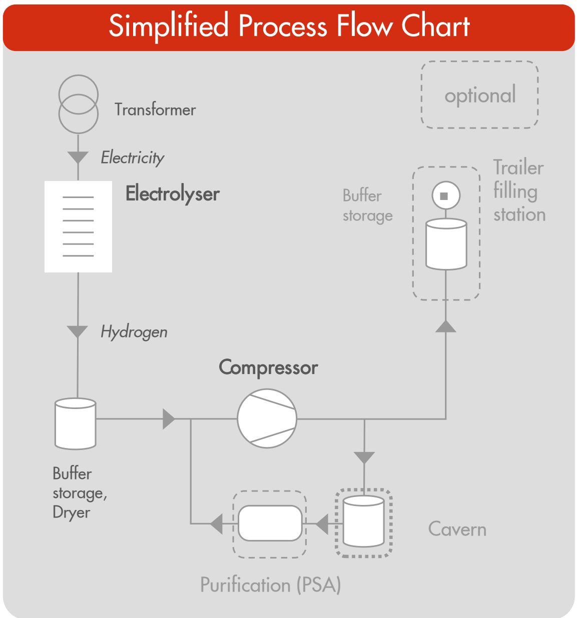

Figure 3: Flow chart of integrated electrolysis and underground hydrogen storage facility

As illustrated in Figure 4, electrolysis dominates the total specific hydrogen plant-gate costs (CAPEX and OPEX) of an integrated hydrogen storage facility with over 80%.[9] The hydrogen production costs from electrolysis are mainly influenced by the capital costs of the electrolyser, its utilization and the (average) electricity purchase price during the time of operation.[10] Other costs such as water costs or operating and maintenance costs are of minor relevance.

[9] The respective shares of the CAPEX only are some 60% for the electrolyser, 30% for the topside equipment (compression and purification), and 10% for the cavern construction.

[10] For a given utilization, the average annual electricity purchase price can be calculated from the electricity price duration curve.

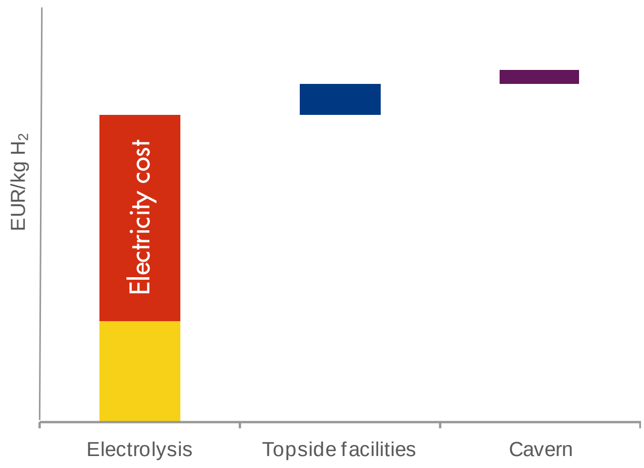

Figure 4: Cost breakdown of an integrated electrolysis and hydrogen storage facility

A key factor determining the costs of electrolysis is the utilization, all the more in the context with intermittent renewable electricity generation. A high electrolyser utilization reduces the specific share of electrolyser capital costs in hydrogen production cost; on the other hand, a higher utilization increases electricity costs, as hours of expensive electricity will increasingly be included. Hence, in order to minimize hydrogen costs, electrolyser utilization has to be balanced with the electricity price.

The economic simulation of an electrolyser shows that the optimum utilization, resulting in lowest hydrogen production costs is in the order of 3,000 to 6,000 hours, with a relatively flat cost profile in this range. With less than 2,000 operating hours, the high relative share of the electrolyser CAPEX increases the hydrogen costs to an uncompetitive level. For a utilization of 40-50% and average wholesale electricity prices of 40-50 €/MWh_{el}, electricity costs alone account for more than 50% of electrolysis costs in most cases; this illustrates that production costs are very sensitive to electricity prices during operation. Electricity prices, however, may vary significantly between countries.[11]

For a better understanding of the average utilization of electrolysers run by 'surplus' electricity it is useful to calculate residual load duration curves for different penetration levels of intermittent renewables.[12] Figure 5 (left side) depicts typical residual load duration curves for a 30% and 80% share of intermittent renewables generation of total electricity demand, estimated for 2025 and 2050 respectively.

[11] In reality, electricity prices may be significantly higher, with country-specific taxes and fees added to the wholesale price.
[12] Residual load is the difference between the total electricity demand and the residual demand. The latter corresponds to all power generation options excluding wind and solar-PV. Residual load consists, therefore, only of wind and solar-PV.

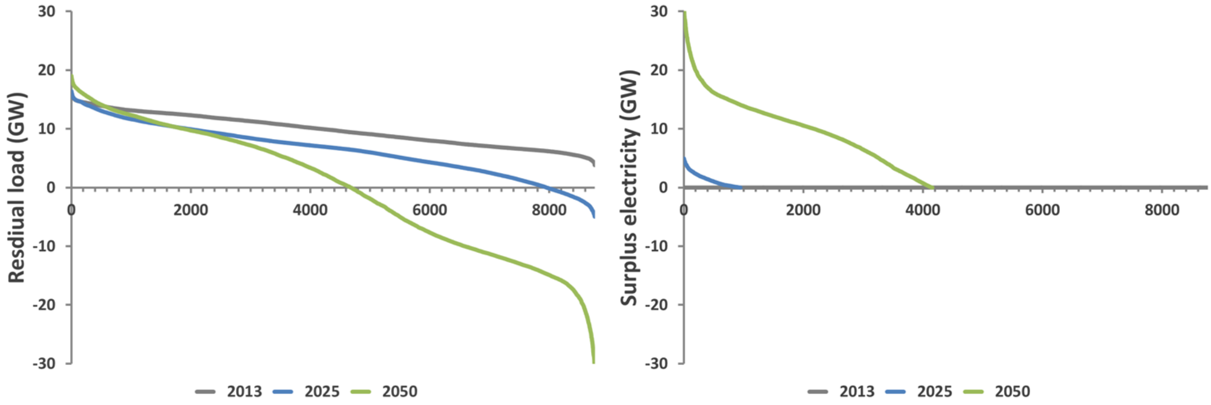

Figure 5: Residual load and surplus electricity duration curves from the Dutch case study

The part of the curves under the x-axis is a measure for the amount of electricity that is produced, but for which there is no immediate demand;[13] these surplus electricity duration curves are shown at the right hand side of the graph. Clearly, in 2025 the amount of surplus is still limited, occurring in the order of 500-1,000 hours per year, due to the low (<30%) share of fluctuating renewable electricity generation. By 2050, with an intermittent renewables share of some 80%, substantial amounts of surplus electricity occur during a total of 4,000-5,000 hours within a year; however, without considering any other storage technologies or flexibility measures being implemented over time.

The following figure illustrates, again exemplarily for the Dutch case study, how the specific hydrogen production costs at plant gate depend on the actual utilization of the electrolyser. The bandwidth shown at the left-hand side of the figure mainly indicates differences in average electricity price assumptions and electrolyser CAPEX.[14] At a low utilization of less than 1,000 hours, hydrogen costs are prohibitively high, in the order of at least 10 €/kg$_{H2}$ and more. This means that the electrolyser would have to be operated with additional electricity purchased from the power exchange (grid) at lowest possible prices, in order to reach a utilization that minimises the hydrogen production costs to a cost-competitive level; depending on the CO_2 intensity of the grid mix, however, this will effectively increase the CO_2-footprint of the hydrogen produced. Between 3,000 and 4,000 hours hydrogen plant gate costs start leveling out in the order of 2-6 €/kg$_{H2}$.

[13] While the occurrence of surplus may result in negative electricity prices in some countries in the short term, it has been assumed that longer term renewable 'surplus' electricity will need to have a price that reflects the generation costs, as otherwise this will be an impediment for further renewables rollout.

[14] Electrolyser CAPEX and average electricity prices for the upper and lower bound vary between 1,200/500 €/kW and 52/39 €/MWh, respectively.

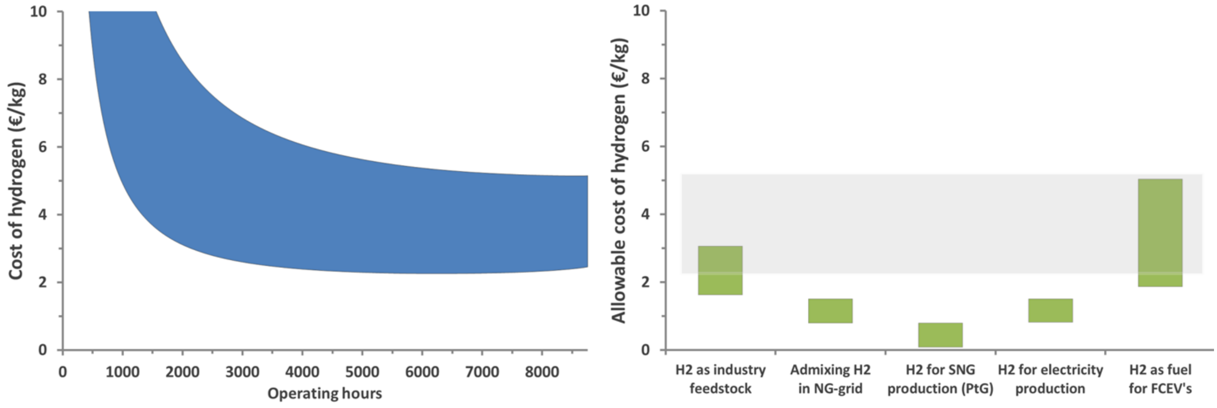

Figure 6: Range of actual and allowable hydrogen production costs for different end-uses

Based on these assumptions and according to the analysis, to be cost-competitive the following hydrogen plant gate costs would be required (excluding distribution and margins):

- for sales into the mobility market: between 2-5 €/kg$_{H2}$ (excluding distribution to hydrogen refueling station, value added tax, fuel tax, and actual station cost),
- for sales to industry: between 2-3 €/kg$_{H2}$,
- for injection into the natural gas grid: between 1-1.5 €/kg$_{H2}$
- for conversion into Synthetic Natural Gas (SNG) by methanation: less than 1 €/kg$_{H2}$, and
- for re-electrification: less than 2 €/kg$_{H2}$.

This compares to actual plant gate costs in the order of 2-6 €/kg$_{H2}$. The scenario analysis indicates that, except for the use in the mobility sector, no other hydrogen use will result in a positive business case under the assumed energy and CO_2 price conditions and in the absence of favourable policy support measures. The simulations further show that under the assumptions of this study hydrogen storage for power-to-power applications, i.e. re-electrification, is economically not attractive; however, it may become a necessity with a very high renewables share and with very stringent CO_2 emission limits, but would require the right policy incentives.

From the economic analysis of the commercial viability of hydrogen used in the aforementioned relevant markets, the hydrogen-for-transport market clearly emerged as the most attractive one, for each country. The reason is that the sales price benchmark for hydrogen is set by conventional liquid fuels, in combination with the poorer efficiency of conventional drive systems compared to hydrogen FCEVs. In any of the other markets, where hydrogen from electrolysis has to compete on a heating value basis with the price of natural gas, it is not cost-competitive under the energy and CO_2 price assumptions considered.

Summary and conclusions

In summary, the analysis of all case studies for hydrogen underground storage arrives at the following high-level conclusions:

- In the considered HyUnder countries, a share of intermittent renewables which covers about 30-40% of the national electricity demand already could result in some TWh’s of so-called surplus electricity that needs to be accommodated in the energy system. Higher shares of 60-80%, and more, could result in tens of TWh’s of surplus electricity, annually, in countries such as Germany, the Netherlands, Spain and the UK.
- Underground storage of hydrogen in salt caverns is a technically feasible option for large-scale storage of electricity, but requires a suitable geology as well as public acceptance.
- There is geological potential for underground hydrogen storage in salt caverns in all countries scrutinized. In particular, Germany and the Netherlands seem to offer good geological conditions in their northern parts. Initially, there will be a preference for existing natural gas storage sites because of availability of required infrastructures.
- The specific construction costs of salt caverns decrease significantly with size, with investments for caverns >500,000 m^3 in brown field sites ranging from 40-60 €/m^3. Depending on the distance to a suitable brine processing or disposal site, the costs for a new brine pipeline may add significantly to the total cavern construction costs. Likewise, cushion gas, which accounts for up to one third of the hydrogen gas volume, represents another significant cost element.
- Electrolysis dominates the total costs of an integrated production and underground hydrogen storage facility with over 80% (at some 50% utilization), of which electricity costs have a major share. Although a cavern requires a significant upfront investment, it has a relatively small contribution to the total specific hydrogen costs of <0.5 €/kg.
- Despite the higher specific costs of a smaller cavern of some 50,000 m^3 compared to a large cavern, the impact of the cavern investment is still relatively small and may initially justify the development of smaller caverns.
- Besides electrolyser CAPEX and electricity purchase prices, the costs of hydrogen from electrolysis strongly depend on the electrolyser utilization. At less than about 2,000 hours the capital costs start to dominate the production costs, making hydrogen from electrolysis increasingly expensive. Because simulations indicate that it may take quite some time before situations with significantly more than 2,000 hours of surplus are reached, storage of surplus

electricity as hydrogen does not seem to represent a near-term economically viable case. Improving the utilization and therefore the economics of electrolysis would require the purchase of additional electricity from the grid.

- Hydrogen energy storage as a means to store renewable electricity via electrolysis and underground storage is economically very challenging. In the short term, under the assumptions taken, the transport sector is the only market expected to allow a hydrogen sales price that may enable the commercial operation of an integrated hydrogen electrolysis and storage plant.
- Where hydrogen from water electrolysis has to compete on a heating value basis with natural gas, i.e. where the benchmark for the hydrogen sales price is set by the price of natural gas, such as in the case of admixture to the natural gas grid, when used as feedstock in industry or for re-electrification, it is not economic. Therefore, potential business cases for other sectors depend on the “willingness-to-pay a premium” by the end-user, or a very favourable policy support. Specifically, the use of ‘low-CO_2’ hydrogen (from electrolysis) in industry depends on its cost-competitiveness against natural gas reforming (SMR). It is questionable whether this will happen in the absence of a regulation that allows monetizing its potential CO_2 benefits.
- Not any single industry sector alone will create a viable business case for underground hydrogen storage. Initially, hydrogen energy storage would need a combined pull from the power balancing market and the mobility sector, as it is otherwise unlikely to be implemented widely. Over time, other markets would have to fully develop to leverage the economic synergies with hydrogen energy storage.
- Sensitivity analysis indicates that the most important factors for a potential business case are both low electrolyser CAPEX and significant periods of low electricity prices, which in the case of re-electrification should be accompanied by a very high volatility, i.e a very high spread in electricity prices. The future development of electricity prices, and more generally electricity market designs, and the actual pricing of ‘surplus’ electricity are among the biggest uncertainties. Other factors that could contribute to a positive business case include favourable feed-in tariffs for ‘green’ fuels, reduced grid fees and a significant increase of CO_2 certificate prices to a level of 100 €/t.

The decarbonisation of the European energy system faces the challenge of how to integrate an increasing share of intermittent renewable energies. Hydrogen is one of the options that may facilitate this integration, but is in competition with other options. Concluding, it can be said that underground hydrogen storage may become a viable option for large-scale electricity storage for weeks and months and make economic sense in places with (i) suitable geology, (ii) electricity generation from intermittent renewables and surplus in the order of tens of TWhs over extended periods, (iii) low electricity prices during a significant part of the year and (iv) a favourable policy framework. However, in the “merit order of flexibility solutions” to integrate fluctuating renewable energies, hydrogen is certainly not the first option that will be applied and its competiveness as storage option hinges on its successful introduction as low-CO_2 energy carrier in other sectors, most importantly the emergence of hydrogen mobility.

Outlook

The increasing need for flexibility options to facilitate ongoing implementation of electricity from intermittent renewable energy sources is not expected to drive the deployment of hydrogen energy storage on a structural basis in the near-term. But hydrogen definitely has a role to play in the longer term as a low/zero-CO_2 energy vector in a highly decarbonised energy system. To use its full potential, hydrogen needs to become an integral part of the energy system as universal energy carrier next to electricity, with its additional capability of electricity storage.

An example of this role already becomes apparent in the automotive industry where hydrogen developments have entered a new phase. The German H_2Mobility initiative, for example, has recently announced plans to establish 400 hydrogen refuelling stations until 2023, and similar market preparation and early market development initiatives are being developed in other European countries like the UK or France, as well as in Japan, the USA and in South Korea. Furthermore, several OEMs (Toyota, Honda, Hyundai, and Daimler) have signalled intentions for market introduction of FCEVs between 2015 and 2017. Fuel-cell based electric mobility in combination with hydrogen from water electrolysis, ideally using renewable electricity, is also one of the few options able to meet future CO_2 emission reduction targets for the transport sector.

The HyUnder project has solely focused on the role of underground hydrogen storage as a technically feasible means for large-scale electricity storage, without in detail considering hydrogen energy storage in the context of the wider set of options to integrate fluctuating renewables. While technically feasible, the economic viability of hydrogen as a means for renewable electricity storage will depend on many energy system-specific parameters. These comprise the emergence of new structures in the power markets with a high renewable electricity share, a new market design for ancillary services as well as the level and spread of electricity prices. Their influence should be analysed in more detail and in the context of other means to integrate renewables at large-scale, such as the extent of curtailment, the ability of the required electricity grid extension to keep pace with the build-out of renewable generation capacity or the impact of large-scale deployment of battery storage:

- Specifically, a need for further assessment has been identified whether it will be possible to improve the business case for electrolysis in the short to medium term by leveraging additional revenues from the balancing power market, thereby easing the pathway through the early implementation phase. This could be the bundling of ancillary grid services performed by electrolysers, which would be additional to the provision of large-scale energy storage, and which today is also partially impeded by existing regulations.
- The penetration of renewable energies is increasing all across Europe and hence the intermittency of electricity supply. If underground hydrogen storage is expected to play a role in a future renewable energy system, there is a need for hands-on operational experience and demonstration in preparation of future markets, as it may well take more than a decade from the decision to start developing first hydrogen salt cavern projects to the implementation of the learnings of such projects in appropriate technical standards and suitable policy, market and regulatory frameworks. This would call for action to incentivise the development of demonstration projects.
- Although residual electricity storage per se does not justify the construction of a hydrogen cavern in the short term, cavern storage may enable other hydrogen applications and business cases in relation to its use in industry and transport, such as for (back-up) supply and trading, as distribution hub as well as for hydrogen import/export; given the stochastic nature of the hydrogen production profile from surplus electricity, large-scale hydrogen admixture to the natural gas grid would also require buffering capacity in order to maintain a constant gas composition. Incentivizing the construction of hydrogen caverns for these applications, which may be more economically viable use cases, would put the required infrastructure in place that could later on also be used for large-scale storage of electricity.
- Especially during the early transition and introduction period, all options and all markets are in need of favourable policy and regulatory frameworks with high level of continuity, in order to reduce early investment risks. Specific policy measures have not been defined in the project.

The HyUnder project was initially motivated by the fact that many studies hint at a significant (double digit TWh) amount of surplus renewable electricity supposed to occur by 2050, at which scale the conversion to hydrogen (as a first step) is currently the only storage option considered feasible, given its energy storage potential.

However, the underlying economic assessment of all case studies has shown that the development of potential business cases will be challenging; this is mainly due to the fact that hydrogen from electrolysis struggles to be cost-competitive with other hydrogen production routes, all the more in the absence of regulation that enables the monetization of its potential CO_2 benefits. Without (the pull of) an emerging hydrogen mobility market and the exploitation of synergies between different energy sectors (electricity generation and transport) as well as a favourable and sustained policy support, hydrogen underground storage will be difficult to develop.

This apparent mismatch between the perceived technical necessity for large-scale electricity storage on the one hand and low profitability of hydrogen underground storage for most application cases on the other hand, leads to the question how else to enable and incentivise the integration of an increasing share of intermittent renewables as a means to achieve the EU's long-term climate targets.

Recommendations to the FCH JU

- Maintain focus on electrolysis as a key technology for low-CO_2 hydrogen production. Reach technology cost goals by R&D, and implement calls that aim at demonstrating and improving the performance of electrolysers for electricity storage and ancillary service applications across a number of countries with a high expected share of intermittent renewables.
- Perform a review of regulatory regimes for ancillary services like balancing power in all EU countries and the potential role for electrolysers, as a means to leverage additional revenue streams.
- Maintain a placeholder for an integrated electrolysis and underground hydrogen storage demonstration project in the Multi Annual Work Programme (MAWP) in order to gain operational experience, engage with public authorities on permitting requirements and test public acceptance. A small-scale project may entail a 50,000 m^3 cavern and 10 MW_{el} installed electrolyser capacity; the total costs for such a project, including investment for topside facilities (hydrogen compressors and purification), operational costs and project development are estimated to be in the order of 30-40 M€.

  Review the case for underground hydrogen storage in the EU in 2018 to decide on the placement of a call for proposals towards the end of the FCH JU program; this should include a review of the business cases for various hydrogen applications and the external energy-political and regulatory environment, as well as the identification of locations that offer promising opportunities to develop first commercial projects. Depending on the business case outlook this could result in the development of a European Action or Implementation Plan.
- Further practical understanding of the technical challenges of storing large quantities of hydrogen in caverns is required. This includes the interplay of the

rock formations with the well with its technical installations (steel, cements, seals) and potential reactions with hydrogen. In addition, given the limited geographical spread of suitable salt formations for hydrogen storage, feasibility studies could focus on exploring porous formations (aquifers and depleted gas reservoirs) for underground storage.

- Explore business cases for hydrogen caverns other than for electricity storage, such as for hydrogen back-up supply for industry, as distribution hubs for mobility markets and to facilitate future import/export of hydrogen, possibly including building a strategic energy reserve.