"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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Executive Summary

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R E P O R T

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Executive Summary

The intermittent nature of many types of renewable energy, like wind or photovoltaics, poses challenges in terms of their large-scale system integration. Their integration will require a mix of different solutions, including grid expansion, curtailment of generation peaks, demand-side management, flexible fossil-based generation, and storage; besides additional grid services to maintain grid stability. The role of any particular solution will vary by country and location and will depend among others on the respective share of fluctuating renewables.

For Germany, it was found that the **electrolysis of water** to produce hydrogen **in combination with hydrogen underground storage** (where geologically feasible), is a readily available and technically feasible option for large-scale chemical storage of fluctuating renewable electricity. As a result, there is a rapidly growing interest in the role electrolytically produced hydrogen could play for the system integration of intermittent renewable energies, i.e. by enabling large-scale storage of "surplus" renewable electricity, such as from wind energy. The **northern part of Germany** in particular is ideally positioned to become a lighthouse region for demonstrating the feasibility of underground storage of hydrogen, because of

- its large renewable energy potential (specifically onshore and offshore wind energy),
- existing and growing electricity grid constraints,
- ideal geological conditions,
- an existing natural gas storage infrastructure, and
- an existing industrial hydrogen market as well as a potentially emerging hydrogen mobility market.

At the same time, hydrogen developments in the automotive industry have entered a new phase and the German H_2-Mobility initiative has recently announced plans to establish 400 hydrogen refuelling stations until 2023. Furthermore, several OEMs (Toyota, Honda, Hyundai, and Daimler) have signalled intentions for market introduction of FCEVs between 2015 and 2017. With these public announcements, Germany is one of the countries with the most visible hydrogen and fuel cells program globally. On the other hand, water electrolysis (ideally using renewable electricity) is one of the few hydrogen supply options for fuel cell based mobility to meet future CO_2 emission reduction targets (next to biogas reforming or clean hydrogen import), as the option of implementing CCS in Germany is unlikely to be accepted.

On the background of the European goals to significantly reduce greenhouse gas emissions by increasing the share of renewable energies in all energy sectors including transport, there is an opportunity to **leverage synergies between hydrogen as a storage medium and as a potential "green" transport fuel**. Possible synergies are expected e.g. from shared infrastructures, using hydrogen as the link between renewable energy and the transport sector.

The favourable conditions already mentioned – including being an **early market for FCEV commercialisation** – put **(northern) Germany** in a very good position for demonstrating the concept of underground hydrogen storage in Europe.

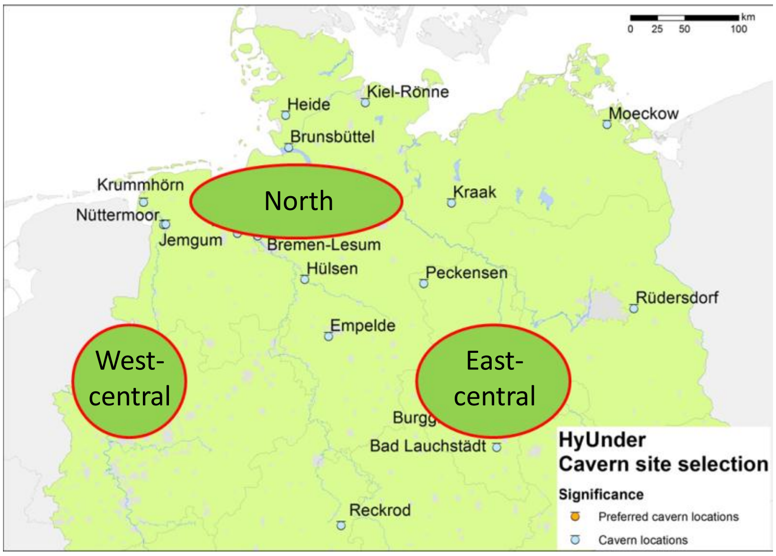
In this study it has been assumed that underground storage of hydrogen will initially be driven by an increase in "surplus" renewable electricity. A "surplus" of renewable electricity has further been defined to occur when the difference between the electricity generation from renewable sources and conventional must-run power plants exceeds the overall demand at any given point in time. Using a very simplified model of the German electricity sector, and assuming an ideal "copper plate" electricity transmission system (i.e. neglecting any possible network congestions), LBST has calculated the total annual surplus electricity arising this way; deficits arising from renewable generation not being able to cover the electricity demand have not been quantified.

Timing, scale and location of the occurrence of this surplus depend on the speed, scale, and type of renewable electricity rollout. The modelling of the German electricity sector until 2050, based on achieving a 35% renewable electricity target by 2020, 50% by 2030, 65% by 2040 and 80% by 2050 (in line with the BMU "Leitstudie 2011"), suggests that **annual surplus renewable electricity may become significant after 2030** adding up to about **15 TWh_{el}** (occurring over a total of some 1,600 hours), corresponding to some 300 kt of hydrogen per year **by 2025** and **up to 75 TWh_{el}** (during a total of about 3,400 hours) or 1,600 kt/a of hydrogen **by 2050**. Actual amounts may end up higher, as potential grid bottlenecks have not been modelled; on the other hand, the modelling approach does not take into account other storage technologies, such as batteries, to be rolled out at large-scale, and the impact this may have on any surplus available for conversion to hydrogen.

The estimated **surplus** roughly corresponds to **7% of total intermittent renewable generation by 2025** and to **20% by 2050**. If all surplus would be converted to hydrogen and stored underground under the assumption of an optimum cavern utilization, these quantities would require some **15 caverns of 500,000 m^3 each by 2025 and some 60 caverns by 2050**. Under economic considerations this would result in a total installed electrolyser capacity of about 3 GW_{el} in 2025 and about 20 GW_{el} in 2050, requiring significant multi-billion Euro investments for build-up of respective capacities.

To the extent that the hydrogen stored during situations of renewables surplus does not need to be used to make up for supply shortages during situations of renewables deficits via re-electrification, it can be sold freely on the market. 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 re-electrification (as would be the case for energy deficit situations).

Today, in Germany **26 natural gas underground storage sites are in operation**. They have been investigated in detail concerning their suitability for an early storage of hydrogen. All of these sites are so-called brown field sites, i.e. they are located in existing gas storage fields with *existing* infrastructure for cavern construction. Such sites (initially) are preferred locations for developing hydrogen caverns for a number of reasons like lower expected development costs compared to green field sites, rapid extension of permits, or public acceptance. **6 locations in 3 greater regions in the northern part of Germany (North, West-central, East-central)** were studied in more detail. Even though all these sites have been identified as appropriate, none fully fulfilled all selection criteria defined: the analysis suggests that in the end the decision for a specific site will need to consider the availability of cheap electricity (e.g. by eliminating grid fees) as well as the access to potential future hydrogen markets. With respect to these aspects the decision for an optimum site will follow a **trade-off between the location's vicinity to renewable electricity hubs versus its vicinity to existing hydrogen infrastructure and hydrogen demand centres**. Furthermore, no suitable cavern storage sites have been identified in southern Germany.



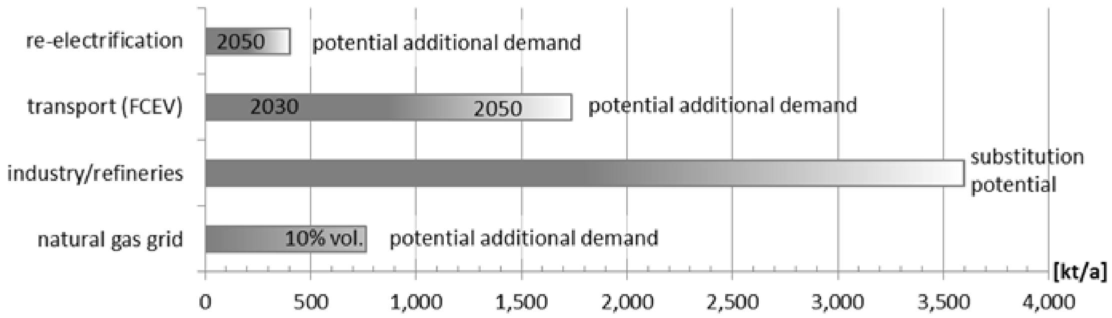
Selected German salt cavern sites for underground hydrogen storage

Details of the three locations are explained in the full document

A 500,000 m^3 cavern was defined as a prototypic or standard size for a "mature" market corresponding to a hydrogen storage capacity of some 4 kt. The total investment for this standard site was assumed to be about M€ 360 in 2025 and M€ 420 in 2050, with an investment share of 60% for the electrolysis plant, 10% for the cavern construction, and 30% for the topside equipment. In accordance with the expected (growing) storage capacity, an average electrolyser power rating of 200 MW_{el} has been assumed by 2025 and of up to 350 MW_{el} by 2050 for one of these prototype caverns.

In order to understand the order of magnitude of the hydrogen "supply side" (i.e. the estimated hydrogen storage demand) vs. the hydrogen demand in different end-use sectors, potential markets for hydrogen have been studied (see figure below). Whereas for industry this would largely be a **substitution** of (part of) today's fossil-based hydrogen production, the other sectors could generate a demand for **additional hydrogen production**. As a rough estimate, German industry alone currently consumes about 3,500 kt of hydrogen annually which in principle is the substitution potential for hydrogen from renewable energy.

According to this assessment, the total additional hydrogen demand by 2050 could be in the order of 2,900 kt of hydrogen annually for mobility, re-electrification and admixture into the natural gas grid. This compares to a total estimated hydrogen supply available from storage of surplus electricity in the order of 300-1,600 kt/a. Assuming a penetration of 50% of hydrogen powered cars by 2050, resulting in some 1,700 kt of hydrogen demand, the transport sector alone could then consume virtually all of the hydrogen producible from the renewable electricity surplus. A potential additional hydrogen demand of up to 760 kt per year could develop from blending 2 to 10 vol.% of hydrogen into the natural gas grid. The hydrogen demand required for re-electrification by 2050 is estimated to be in the order of 400 kt per year.



Potential future hydrogen demand in selected markets in Germany

The following table summarises relevant characteristics of using hydrogen (from electrolysis) in the different market sectors reviewed:

Mobility	Industry	Natural gas grid (renewable-H_2 and -methane)	Re-electrification
• Electrolysis is one of very few zero/low CO_2 supply options (where CCS cannot be applied) • Enables high end-use efficiency in fuel cells compared to ICE • Hydrogen as storage medium and mobility fuel may share joint infrastructure build-up • Benchmark price set by liquid fuels (gasoline/ diesel) • Appears as sole premium market in short- to medium-term to recoup investment for wind H_2 storage • Potential enabler for H_2 into other markets (pull)	• H_2 is a commodity sourced at lowest costs • Benchmark is SMR (natural gas price), with production costs around € 2/kg • Currently no regulation in place at EU or national level (e.g. ETS) to monetize potential CO_2 benefits of 'green H_2' (i.e. as viable CO_2 abatement option or via products with reduced CO_2 intensity) • Currently not cost-competitive for industry	• Can make use of existing infrastructure (with today's German natural gas storage capacity of some 200 TWh) • Admixture of up to 10 vol.% could be technically acceptable for both steel and plastic pipes as well as seals, but instruments and appliances may be the bottleneck, as most stringent appliance sets the ceiling (e.g. today 2 vol.% for CNG cars), other elements such as pore storage may allow no admixture [DVGW 2013]. • Methanation can make direct use of existing natural gas infrastructure, but requires abundant sources of cheap CO_2, reduces system efficiency and increases overall costs • Commercial benchmark is natural gas price – business case hinges on 'willingness to pay a premium' on final customer side • Potential sales of 'green H_2' via certification/GOO	• Power-to-gas-to-power application ("deficit-driven storage"). Only needed with massive system integration of REN (>>70%), but then becomes a must, where feasible. • Benchmark are the costs of (gas-fired) peak load power plants; technically, flexible conventional power plants can provide back-up power until a significant share of renewable electricity generation, however, at increasingly higher costs, CO_2 and operational stresses • Business case driven by volatility / avg. electricity price level, but no near-term business case • Low round trip efficiency (25-40%) • Needs H_2 fuel cell or H_2 turbine • Potential business cases through stand-alone applications

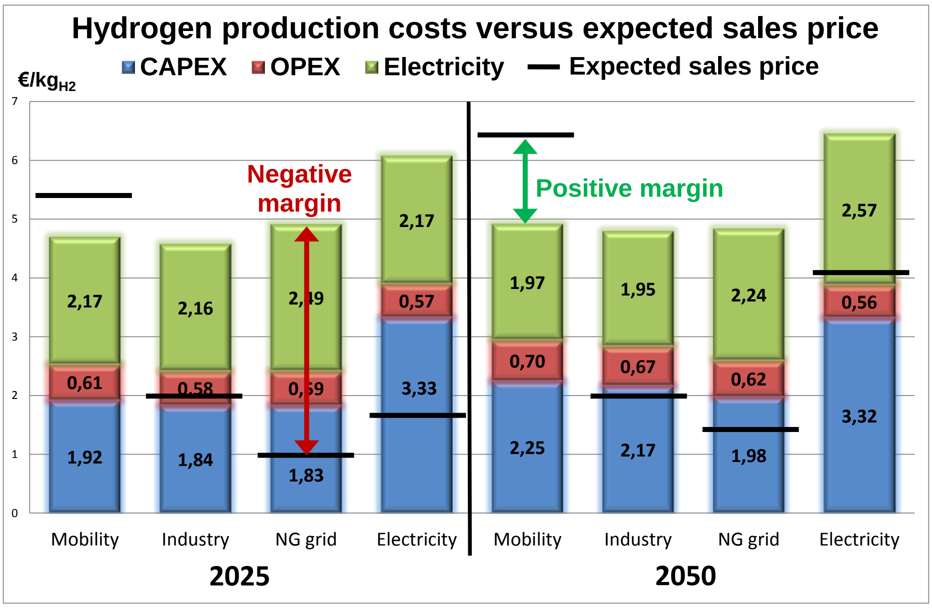
From the detailed economic simulations of the commercial viability of hydrogen used in the four aforementioned relevant markets the **hydrogen-for-transport market clearly emerged as the most attractive one** (see graph below). The reason is that the sales price benchmark for hydrogen is assumed to be set by conventional liquid fuels (gasoline/diesel), in combination with the poor efficiency of conventional drive systems as 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 and will not become cost-competitive under the energy and CO_2 price assumptions of the German BMU "Leitstudie 2011".

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

- for sales into the **mobility market:** below 5.4 €/kg_{H2} in 2025 and 6.3 €/kg_{H2} in 2050 (excluding distribution to the refuelling station and value added tax, but fuel tax exemption assumed),
- for sales to **industry:** below 2 €/kg_{H2},
- for injection into the **natural gas grid:** below 1.0 €/kg_{H2} in 2025 and 1.3 €/kg_{H2} in 2050, and
- for **re-electrification:** below 1.7 €/kg_{H2} in 2025 and 4.1 €/kg_{H2} in 2050.

This compares to actual plant gate costs in the order of 4.7 to 6.6 €/kg_{H2}. The scenario analysis shows that except for the use of hydrogen from underground storage 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.

Electrolysis dominates the total costs of an integrated hydrogen storage facility with over 80%, with electricity costs alone accounting for more than 40%. The average electricity price for the different scenarios was assumed to be between 35 and 40 €/MWh.



The graph compares the H_2 production costs (incl. the cavern costs, and, in the case of transport and industry application the compression, purification and drying, and in the case of re-electrification also the use of a CCGT plant) with the expected H_2 sales price. The expected sales price sets the ceiling for the allowable H_2 production costs, i.e. where the H_2 production costs are higher than the expected H_2 sales price, there is no positive business case under the assumptions taken here.

High electrolyser utilization reduces the specific share of electrolyser capital cost in hydrogen production cost; on the other hand, higher utilization increases electricity cost, 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 is in the **order of 4,000 hours**. This number results in lowest hydrogen production costs (actually costs are relatively flat in the range of 2,000 to 6,000 hours). With less than 2,000 operating hours, it is the high relative share of the electrolyser CAPEX that increases the hydrogen production costs to an uncompetitive level, beyond 6,000 hours it's the growing share of electricity costs that renders hydrogen production uneconomic.

As the occurrence of electricity surplus typically results in significantly less than 4,000 annual operating hours, the **electrolyser has to be operated with additional electricity purchased from the EEX** at lowest possible prices, in order to reach a utilization that minimises the hydrogen production costs. Depending on the CO_2 intensity of the grid mix, this will effectively increase the CO_2-footprint of the hydrogen produced.

In summary, our analysis of the German Case Study for hydrogen underground storage at large scale arrives at the following high-level conclusions:

- **Meeting the German renewable electricity targets** by 2050, as per the "BMU Leitstudie 2011" scenarios, **results in several tens of TWh of surplus electricity** expected after 2030 (despite a 'copper plate' assumption for the grid). However, quantifying the scale of required electricity storage capacity (and the role of hydrogen in that respect) in the short term is more uncertain.
- **Underground storage of hydrogen** (where geologically feasible) is a **technically feasible** option for large-scale storage of renewable electricity.
- Germany offers **excellent geological conditions** and **prime locations in the northern part** to develop large scale hydrogen underground storage in salt caverns. **Existing natural gas storage sites** are available and **preferred** initially.
- **Electrolysis dominates the total costs** of an integrated underground hydrogen storage facility **with over 80%** (around 50% utilization).
- **Hydrogen production from electrolysis and underground storage, as a means to store renewable electricity, 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 a commercial operation of an integrated hydrogen electrolysis and storage facility. Potential business cases for any sector other than mobility depend on the "willingness-to-pay a premium" by the end-user. Where hydrogen (from 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 or for re-electrification, it is not economic, unless significantly subsidized. Likewise, the additional demand from industry for 'low-CO_2' hydrogen (from electrolysis) depends on its cost-competitiveness and is questionable in the absence of a regulation to monetize its potential CO_2 benefits. Hence, hydrogen production from electrolysis and underground storage would need a pull from the mobility sector, as it is otherwise unlikely to be implemented widely.
- The **sensitivity analysis** suggests that the single most important factors for a potential business case (incl. mobility) by 2025 are both a lower electrolyser CAPEX and cheap electricity prices (incl. an exemption from grid fees). The future development of electricity prices (and more generally electricity market designs) and the actual pricing of 'surplus' electricity are among the biggest uncertainties. The impact of a smaller cavern size (as would most likely be chosen during a demonstration phase and while gradually building up the

hydrogen storage infrastructure) only has a negligible effect on cavern costs due to the relatively high fixed costs of the cavern construction, irrespective of its size.

Outlook

- **If to be exploited to i**ts best, hydrogen needs to become **an integral part of the energy system as universal energy carrier** next to electricity, with the additional role for electricity storage.
- This study has focused on the **role of underground hydrogen storage as a technically feasible means** for large-scale electricity storage, without in detail considering hydrogen 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 (via electrolysis and in combination with cavern storage, where geologically feasible) will depend on many energy system-specific parameters (like the renewable electricity share 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 for instance 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 a grid service performed by electrolysers, which would be additional to the provision of electricity storage.
- **Intersectoral synergies** – such as the joint use of a common hydrogen infrastructure – yet need to be analyzed in greater detail, involving the relevant sectors simultaneously.
- **Especially in the early** transition and introduction period, all options and all markets are in need of **favourable policy support and regulations** with high level of continuity, in order to reduce the commercial risks. Specific policy measures have not been defined.
- 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** of feasibility in preparation of mature markets (expected around 2030), all the more, as the development and construction of

a large **hydrogen cavern project takes several years.** This calls for action to incentivise the development of demonstration projects.

- Germany is not alone facing the challenges of transitioning to a renewable energy system. The penetration of renewable energies is increasing all across Europe and hence the intermittency of electricity supply. As the development of a hydrogen infrastructure takes time, a **European Action Plan** could help in tuning the individual strategies towards a European concept for hydrogen underground storage.

The combination of location factors for large scale underground hydrogen storage in Germany are unique, such as a suitable geology, existing natural gas storage sites, and the potentially emerging hydrogen market for mobility.

Based on the modelling results using the BMU-Leitstudie, a significant (double digit TWh) amount of surplus renewable electricity is supposed to occur by 2050. At such a scale, the conversion to hydrogen (as a first step) is currently the only storage option considered feasible, given its energy storage potential, to cover the expected storage need.

However, the underlying economic assessment of the German Case Study shows 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.

To better understand the reasons for the apparent mismatch between the perceived technical necessity (potential for large scale storage) on the one hand and low profitability of hydrogen underground storage for most application cases on the other hand, based on today's assumptions, it will be necessary to continuously challenge and assess the potential impact of the most important dimensions and constraints underlying our analysis:

- the development of the energy market and specifically the dynamics and level of energy and electricity prices,
- the development of measures and instruments as well as technologies competing with hydrogen underground storage to cope with the fluctuations in future energy supply, and
- the evolution of German and EU policy goals, imposed by relevant policy measures, such as a CO_2 emission regulation and resulting CO_2 pricing.