Expected techno-economic requirements for underground renewable hydrogen storage

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FUEL CELLS AND HYDROGEN JOINT UNDERTAKING

Authors:

Jan MICHALSKI[1], Jan ZERHUSEN[1], Ulrich BÜNGER[1]

[1] Ludwig-Bölkow-Systemtechnik GmbH, Germany

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Ulrich BÜNGER	Ludwig-Bölkow-Systemtechnik GmbH	30.03.2021

Approved by:

Name	Institute	Date
Jan MICHALSKI WP5 Leader	Ludwig-Bölkow-Systemtechnik GmbH	30.032021
Arnaud REVEILLERE Project Coordinator	Geostock	31.03.2021

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1. Background and approach

This report presents the results of Task 5.2 within Work Package (WP) 5 of the Hystories project. The major objective is to provide an initial dataset for the needs for seasonal hydrogen storage across EU-27 on Member State level and in the United Kingdom (UK). Based on the analysis work in previous studies the report identifies required sizing and expected operation of underground renewable hydrogen storage in terms of:

- required energy storage capacity in TWh_{H2},
- maximal storage input and output (defined as capacity-to-input ratio and capacity-to-output ratio, respectively, and calculated by dividing the energy storage capacity by maximal input or output capacity in h = MWh_{H2}/MW_{H2})[1],
- expected total amount of stored hydrogen in TWh_{H2}/a, and
- number of full cycle equivalents (defined as the sum of hydrogen amount injected into and released from the storage within a year divided by storage capacity and multiplied by factor 0.5[2]).

Typically, the optimal storage size and operation result from detailed energy system modelling taking into account techno-economic characteristics of different system elements (such as efficiency and investment costs of various power plants and storage technologies) and boundary conditions (such as fuel and carbon prices or GHG reduction targets). However, in this Task we employ a simplified approach based on the comparison of hourly demand and supply profiles in order to provide rough estimates as a first input for the geological analysis in WP 1 to 4. At this point, it is important to mention that the optimal storage sizing and operation will be calculated and analysed in detail in Task 5.5[3] and Task 5.6[4]. Hence the optimal results from the energy system exercise might be different from the preliminary outcome of the present Task.

In this context, the required storage size and way of operation directly result from the storage filling level for each hour within a prototypical year:

- storage capacity is calculated as maximum filling level minus minimum filling level whereas
- required storage input and output capacity correspond to maximum increase and decrease in storage level, respectively.

The filling level in a given hour equals the filling level in the previous hour plus storage input minus storage output in the given hour. We assume that the storage has the same filling level

[1] In this way the ratio can be also interpreted as the time until an empty storage can be fully filled or a full storage can be fully depleted at the maximum input/output rate.
[2] A full cycle is defined as one cycle consisting of full charging and discharging of the entire storage.
[3] WP 5 Task 5.5: Techno-economic assessment of future scenarios for a widespread deployment of underground renewable hydrogen storage
[4] WP 5 Task 5.6: Sensitivity analysis

in the first and last hour of the prototypical year. Storage input and output correspond to hourly hydrogen supply and demand profiles taking into account intermittent renewable power availability and consumption patterns in various end-user sectors. They are derived by multiplying synthetic hourly profiles (in %/h) by annual hydrogen demand levels (in MWh_{H2}/a) according to different pre-defined scenarios and cases.

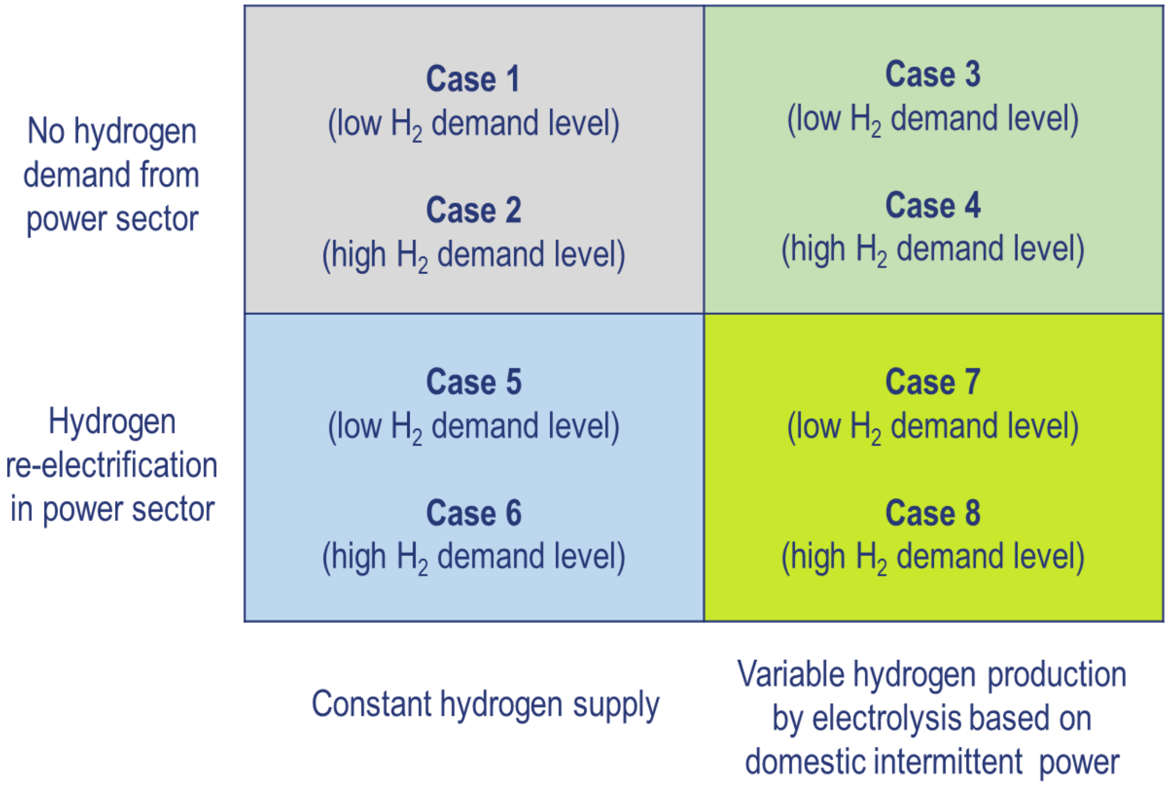


Figure 1: Cases representing possible future developments in respect to major impact criteria on requirements for underground renewable hydrogen storage

In order to capture a full range of possible future developments and to check robustness of results we define eight different cases based on major impact criteria including different hydrogen demand levels, hydrogen supply pathways and variability of demand and supply profiles (see Figure 1):

- **Cases 1 and 2** assume constant hydrogen supply which can be interpreted as hydrogen imports (e.g. via a dedicated pipeline) or hydrogen production independent from renewable power supply (e.g. from steam methane reforming in combination with carbon capture and storage or use). Hydrogen is used in the mobility, industry and buildings sectors but not for re-electrification to balance out renewable energy feed-in in the power sector. In Case 1 we expect a higher direct hydrogen use (i.e. demand in the mobility, industry and buildings sectors) than in Case 2.[5]

- **Cases 3 and 4** represent a full renewable hydrogen supply where hydrogen demand is satisfied by electrolysis based on domestic renewable power supply from wind and solar. Similar to Cases 1 and 2, the power sector is not included in the analysis as we assume that there are other flexibility measures (e.g. dispatchable power plants based on biomethane or pumped-hydro storage) sufficient to balance out intermittent feed-in. Both cases differentiate again in terms of hydrogen demand level in the mobility, industry and buildings sectors.
- **Cases 5 and 6** are similar to Case 1 and 2 in respect to hydrogen supply (i.e. assuming constant hydrogen supply) but taking re-electrification of hydrogen in the power sector into account. We assume that electricity demand in the power sector is fully satisfied by domestic renewable power plants. Hence, the differences in hydrogen demand levels between both cases depend on the demand from all end-user sectors.
- **Cases 7 and 8** are expected to have the largest storage requirement as both hydrogen demand and supply are variable, i.e. supply is based on intermittent power and demand comes from all end-user sectors. Similar to Case 5 and 6 the demand levels between both cases take into account all end-user sectors including hydrogen re-electrification in the power sector.

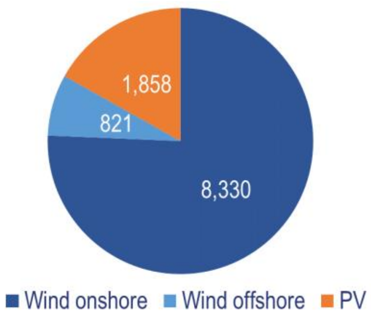
[5] Note that for sake of compatibility both cases should have the same GHG emission reduction targets. The difference in hydrogen use should stem from the degree of electrification in different end-user sectors, i.e. e.g. penetration of battery electric vehicles (BEVs) vs. fuel cell electric vehicles (FCEVs) in the mobility sector or the use of electric heat pumps vs. fuel cell based combined heat and power (CHP) devices in the building sector.

2. Assumptions and input data

The analysis in this Task is mainly based on data from the study “Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure” conducted by Trinomics, LBST and E3M for the European Commission – DG ENER.[6] The objective of the study was to investigate the role of biomethane and hydrogen for achieving long-term GHG emission reduction targets in Europe. The analysis included a detailed modelling of the European energy system in three scenarios with a different mix of end-user technologies, i.e. strong electricity, green methane and hydrogen use, for the time horizons 2030 and 2050. In this context, the calculations in this Task are based on the following data for each Member State and the UK from the abovementioned study:

- Annual electricity and hydrogen demand levels
- Annual renewable electricity generation potential
- Synthetic hourly feed-in profiles for wind onshore, wind offshore and photovoltaics (PV)
- Synthetic hourly demand profiles for power and hydrogen from the mobility, residential (heating and warm water) and industry sectors
- Electrolysis and re-electrification unit efficiency

The annual electricity and hydrogen demand levels correspond to 2050-values on the one hand from “Scenario 1: Electric” with a focus on electricity-based end-user applications (Case 1, 3, 5, and 7 with low H_2 demand level) and on the other hand from “Scenario 3: Hydrogen” with a strong focus on hydrogen-based end-user applications (Case 2, 4, 6 and 8 with high H_2 demand level). Hydrogen demand covers all end-user sectors including industry (for process heat or feedstock), households and services (for heating and warm water) and mobility (hydrogen as a fuel).



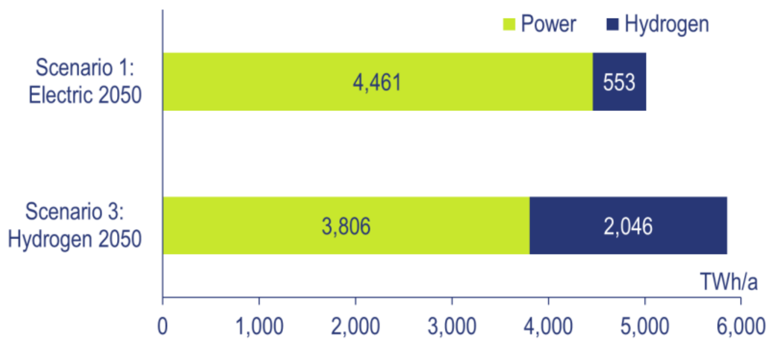


Figure 2: Renewable electricity generation potential (left) and expected power and hydrogen demand in “Scenarios 1: electric 2050” and “Scenario 3: Hydrogen 2050” (right) in EU-27 and UK according to Trinomics/LBST/E3M (2019).

[6] Trinomics/LBST/E3M (2019). Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure. September 2019.

As depicted in Figure 2 in cases with low H_2 demand level almost 90% of the concerned final energy consumption[7] is based on electricity (ca. 4,500 TWh/a) whereas hydrogen has a small share of only 10% (ca. 550 TWh/a). In cases with high H_2 demand level power demand is still significant (ca. 65% or 3,800 TWh/a), but hydrogen-based end-user applications play a much larger role (ca. 35% or more than 2,000 TWh/a). The difference in overall final energy consumption between both scenarios (ca. 5,000 vs. 6,000 TWh/a) is due to the fact that electricity-based applications such as BEVs or electric heat pumps are more efficient than the hydrogen-based alternatives. In this context, it is important to mention that both scenarios achieve climate neutrality in 2050, however, on different pathways. A similar ratio between electricity and power demand is assumed for each Member State and the UK (see Figure 4 and Figure 5). The largest energy consumers are represented by the six biggest European economies: Germany, France, Italy, the UK, Spain and Poland account for almost 70% of the European power and hydrogen demand.

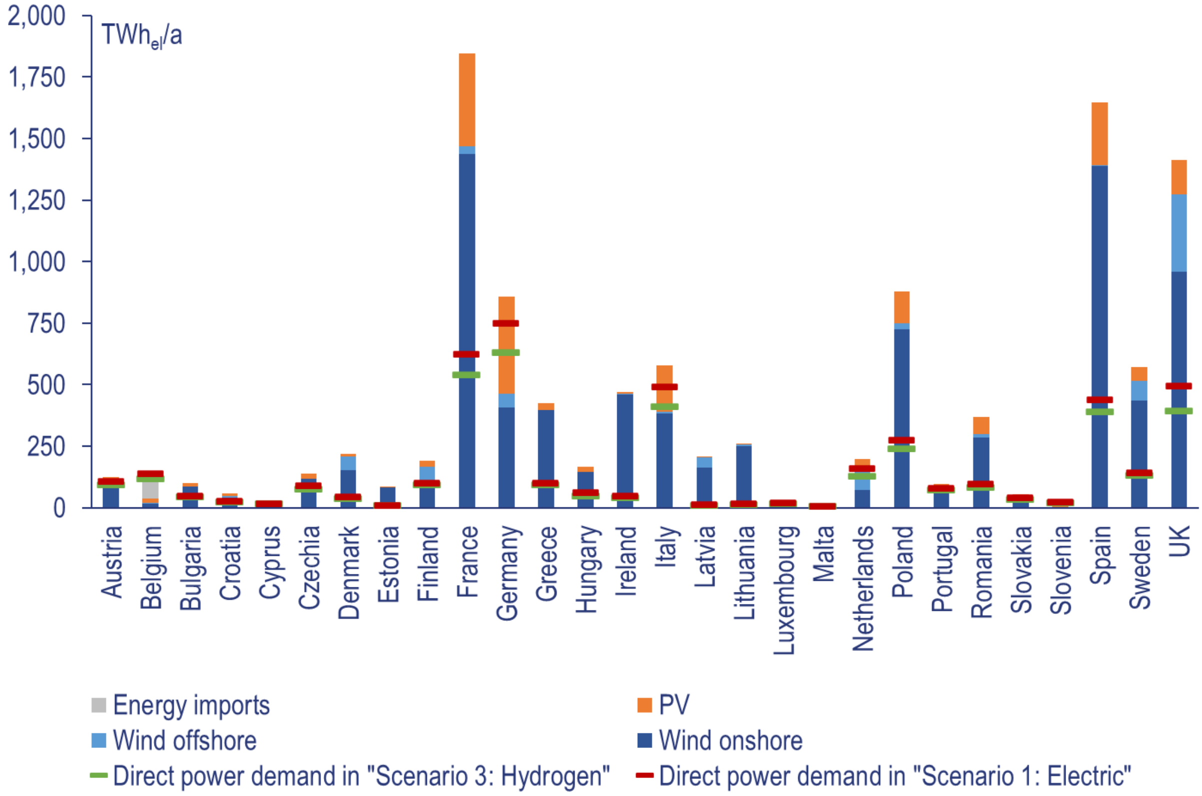


Figure 3: Renewable electricity generation potential and expected direct electricity demand excluding electrolytic hydrogen production in “Scenarios 1: Electric 2050” and “Scenario 3: Hydrogen 2050” per Member State and in UK according to Trinomics/LBST/E3M (2019); the technical potential above the threshold for direct electricity use from both scenarios indicates the remaining renewable energy for hydrogen production.

The overall potential for renewable electricity generation in EU-27 and the UK of ca. 11,000 TWh/a is much larger than the expected power and hydrogen demand. This means that from

[7] Note that for the sake of simplicity we focus only on electricity and hydrogen as final energy and exclude all other energy carriers.

a technical perspective EU-27 and the UK are capable to supply all required energy from domestic sources.[8] However, more than 75% of renewable power is based on wind onshore, which in practice might be difficult to fully utilize due to economic and societal reasons (e.g. high land and infrastructure costs and/or limited public acceptance). This is true for a number of Member States. Nevertheless, the potential for renewable power generation from wind and solar is not equally distributed among the countries. In particular, in energy-intensive economies like in Germany, Italy, the Netherlands the overall power demand including electricity for hydrogen production exceeds the expected demand (see Figure 3). In five smaller Member States (Belgium, Cyprus, Malta, Luxembourg, Slovenia) the renewable power potential is even smaller than the projected direct electricity consumption[9]. In both cases we assume corresponding imports of renewable energy either from other Member States or from outside the EU. Moreover, the renewable energy mix varies between the countries according to their specific geographic conditions.

The synthetic hourly profiles are taken from Trinomics/LBST/E3M (2019) and are mainly based on historical values. In this context, the ENTSO-E Transparency Platform provides country-specific feed-in patterns for wind and solar power as well as demand profiles for electricity. These demand profiles are further adapted by expected consumption by BEVs based on potential charging behaviour form literature and by electric heat pumps based on historical temperature data and temperature-dependent efficiencies. In case of hydrogen demand, the study assumes similar historical patterns for hydrogen consumption in the transport sector as for diesel and gasoline, similar temperature-dependent heating behaviour as for electric heat pumps[10] and constant energy consumption by the industry sector. The hourly hydrogen demand for re-electrification in the power sectors in Cases 5 to 8 results from the residual load curve defined as expected power demand minus renewable feed-in. This means that positive residual load has to be supplied by hydrogen power plants whereas negative residual load offers surplus electricity which is fully utilised by electrolysers. Table 1 provides the efficiencies for both electrolysis and hydrogen power plants.

Table 1: System efficiencies for electrolysis (lower heating value) and hydrogen power plants (electric efficiency including balance-of-plant)

Technology	Efficiency
Electrolysis	67%
H_2 power plant	40%

[8] This is also true for the most challenging hydrogen-focused Scenario 3 with the largest overall final energy consumption and lowest efficiency of end-user applications requiring less than 7,000 TWh/a of renewable power (3,800 TWh/a of direct electricity use and ca. 3,000 TWh/a for electrolytic hydrogen production assuming an electrolysis efficiency of 67%).
[9] I.e. excluding electrolytic hydrogen production from domestic sources.
[10] However, with a constant efficiency.

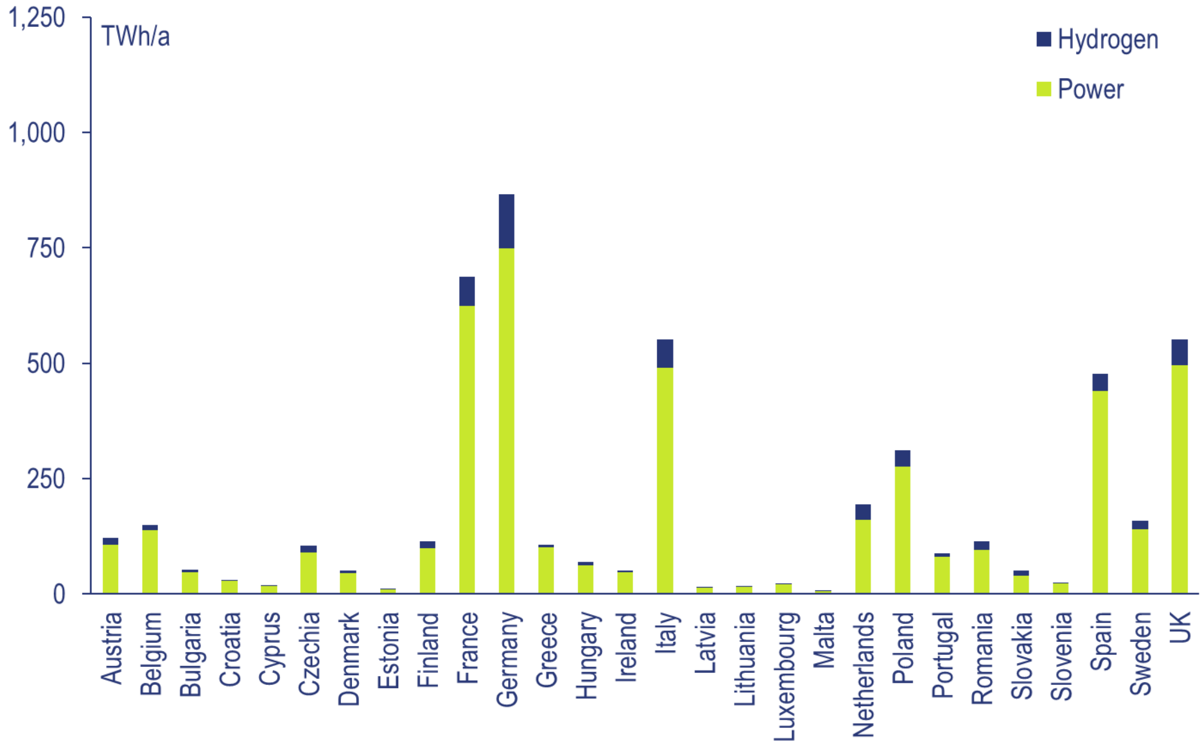


Figure 4: Power and hydrogen demand in 2050 in "Scenario 1: Electric 2050" per Member State and in the UK according to Trinomics/LBST/E3M (2019).

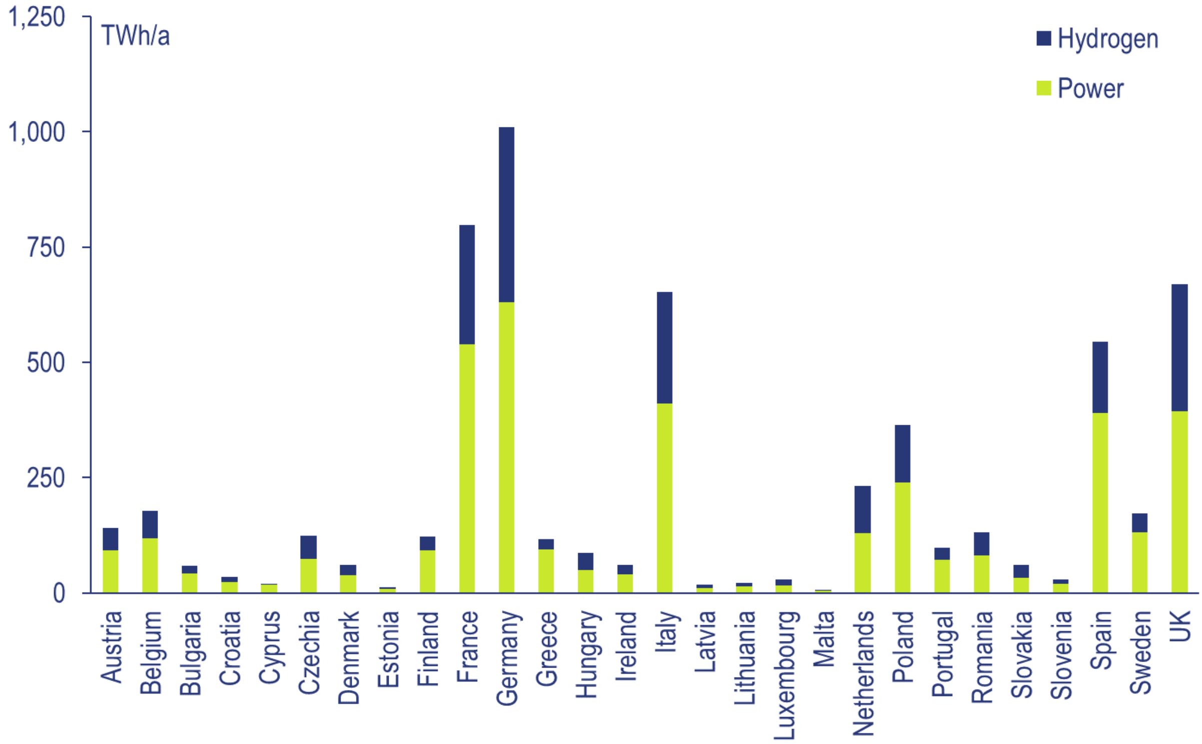


Figure 5: Power and hydrogen demand in 2050 in "Scenario 3: Hydrogen 2050" per Member State and in the UK according to Trinomics/LBST/E3M (2019).

3. Requirements for underground renewable hydrogen storage

As mentioned in previous chapters, we present the requirements for underground renewable hydrogen storage based on energy storage capacity (in TWh_{H2}), maximal storage input and output (in h = MWh_{H2}/MW_{H2}), expected total amount of stored hydrogen (in TWh_{H2}/a) as well as number of full cycle equivalents.

Figure 6 depicts the range for the required storage capacity on a country basis. Generally, the larger the energy demand in a country the greater both the storage capacity and the range between the analysed cases. In this context, the "big six" (i.e. Germany, France, Italy, the UK, Spain and Poland) account for ca. 75% of the overall required storage capacities in Europe. All other countries have a required storage capacity of less than 25 TWh_{H2} each in all cases. Germany alone with the highest demand and comparatively high share of solar power requires a capacity of ca. 9-130 TWh_{H2} being responsible for 20%-25% of European storage needs of 40-700 TWh_{H2}[11]. As expected, the largest requirements occur in Case 8 including the power sector and high variable hydrogen supply whereas the lowest required capacities can be observed in Case 1 with low constant H_2 supply and without need for H_2 re-electrification in the power sector.

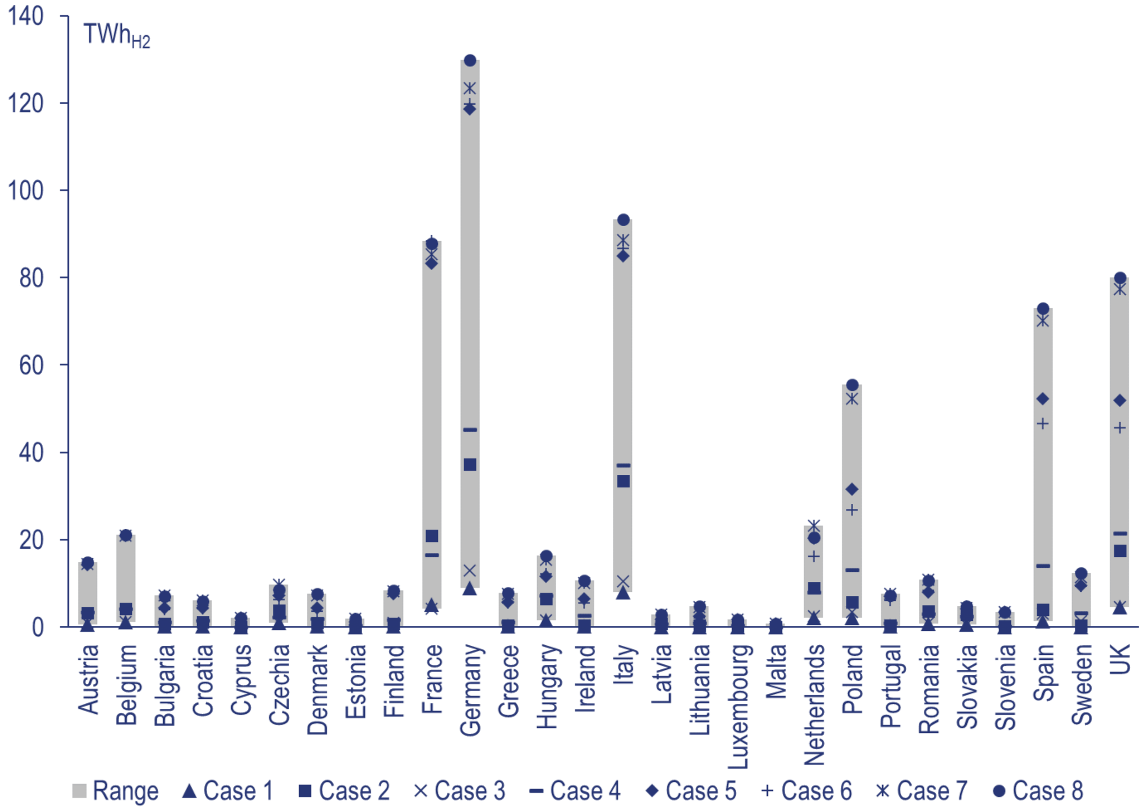


Figure 6: Required capacity for underground hydrogen storage in selected cases.

[11] This corresponds to 13-233 billion Nm^3 H_2 or 1.2-21 Mt_{H2} based on conversion factors of 3.00 kWh/Nm^3 and 33.33 kWh/kg for lower heating value.

Although the required storage input and output capacities follow the required storage capacities the corresponding capacity-to-input ratio and capacity-to-output ratio are quite similar among the selected countries (see Figure 7 and Figure 8, respectively). This can be interpreted as a first indicator that the underground hydrogen storage is operated in a similar way across Europe. The largest capacity-to-input ratio occurs for Case 1 (constant H_2 supply and lower H_2 demand) with more than 1,400 h (58 days) for most countries. This means that in this case the input capacity is very small and it would take at least 1,400 h to fully fill the storage at constant input capacity. The lowest ratio ranges between 170-670 h and strongly depends on the relationship between hydrogen production profiles and thus renewable feed-in and electricity consumption patterns (or power residual load). The corresponding European electrolysis capacity for variable hydrogen production in Cases 3, 4, 7 and 8 ranges between ca. 200 GW_{el} in Case 3 and 2,200 GW_{el} in Case 8.

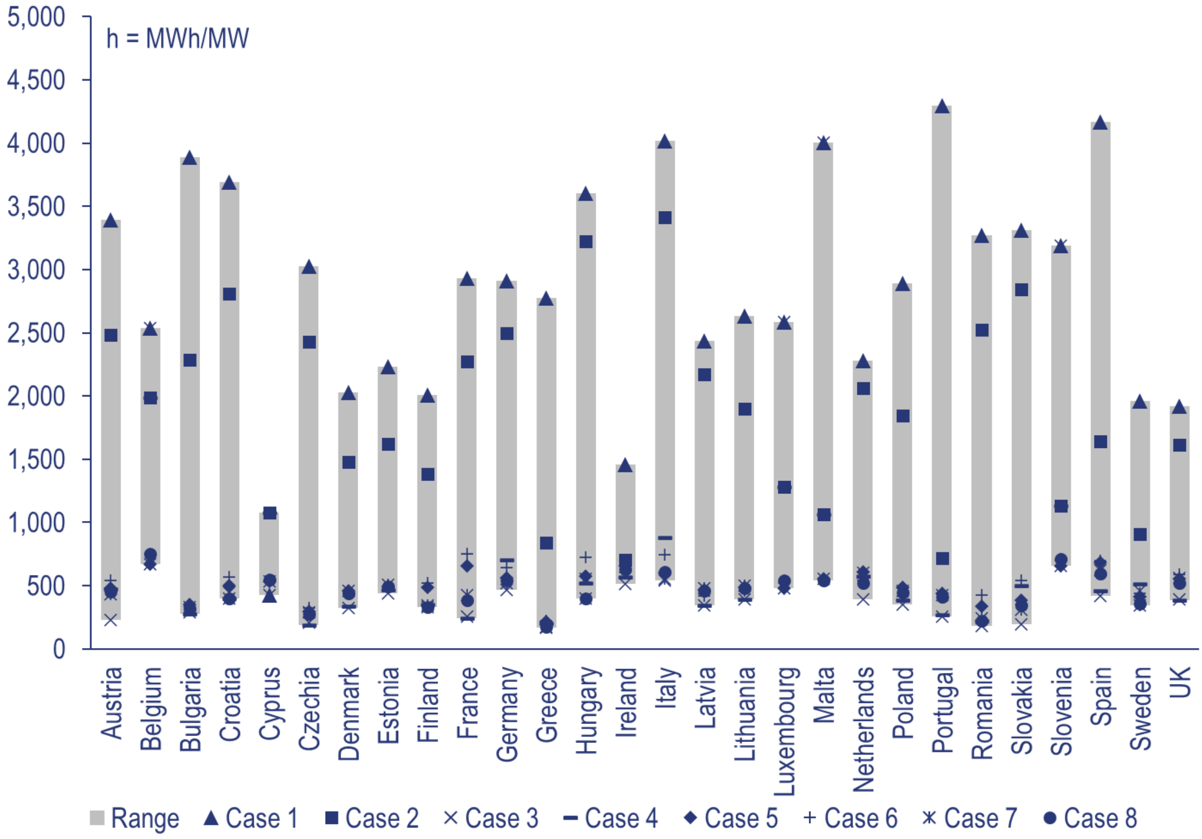


Figure 7: Required capacity-to-input ratio of underground hydrogen storage in selected cases.

In respect to required capacity-to-output ratio (*Figure 8*) the spread between the highest and lowest case and the differences between the countries are much smaller than for storage input. Typically, output capacity correlates directly with hydrogen demand. Hence, the lowest capacities and highest capacity-to-input ratio of more than 1,200-1,600 h occur in Case 1 or Case 2 without the power sector for most countries whereas the highest capacities and lowest ratio can be observed for cases with explicit hydrogen re-electrification needs in the power sector in Case 5 to 8 (140-730 h).

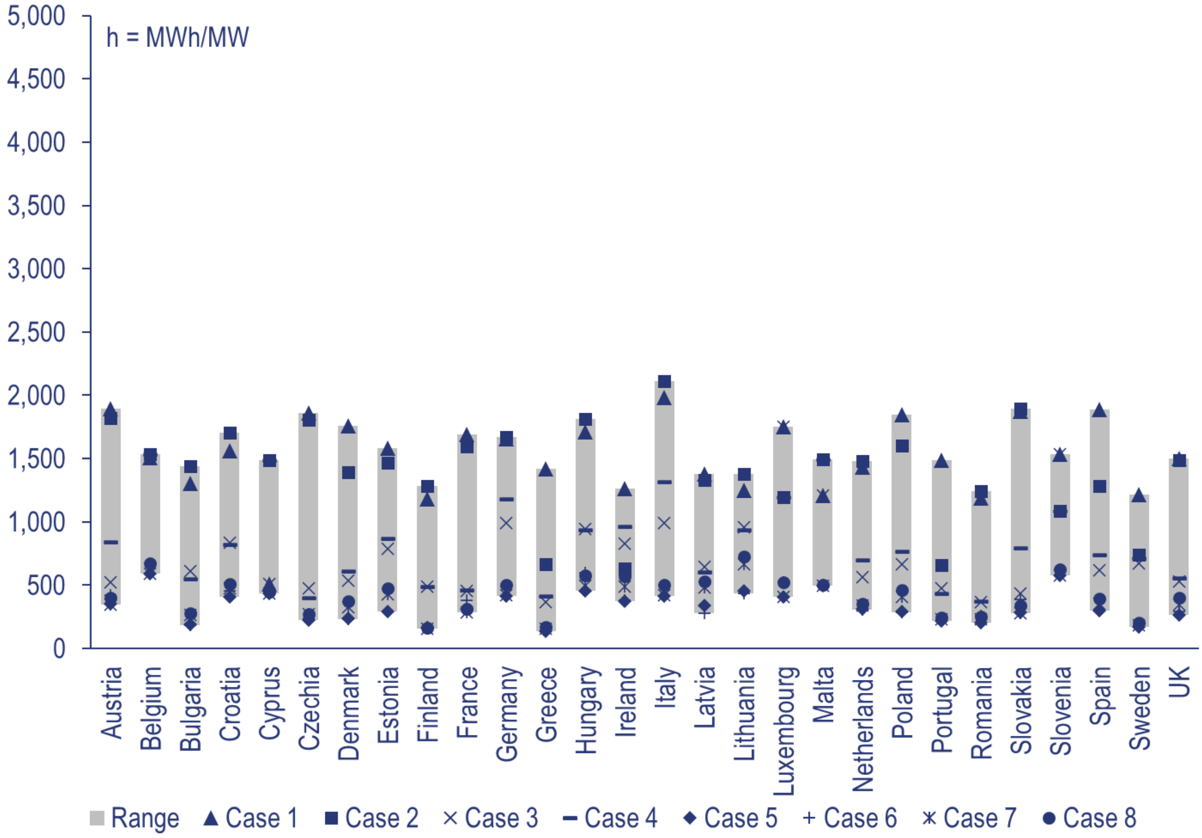


Figure 8: Required capacity-to-output ratio of underground hydrogen storage in selected cases.

Figure 9 shows the amount of hydrogen turnover during a prototypical year for each country. Again, the largest capacities can be observed for the "big six" (Germany, France, Italy, the UK, Spain and Poland) in Cases 7 and 8 (variable hydrogen supply and hydrogen re-electrification on power sector) with the largest energy demand. These six countries account for ca. 70%-75% of the overall European hydrogen storage turnover. In Cases 5, 6, 7 and 8 ca. 1,600-2,200 TWh_{H2}/a need to be stored in European underground facilities corresponding to ca. 34%-60% of the overall annual hydrogen demand (including re-electrification in the power sector) in Europe (see Figure 10 for results for each Member State and the UK). In Case 1, 2, 3 and 4 the amount of stored hydrogen is much lower: ca. 40-440 TWh_{H2}/a or 8%-25% of overall annual hydrogen demand in Europe.

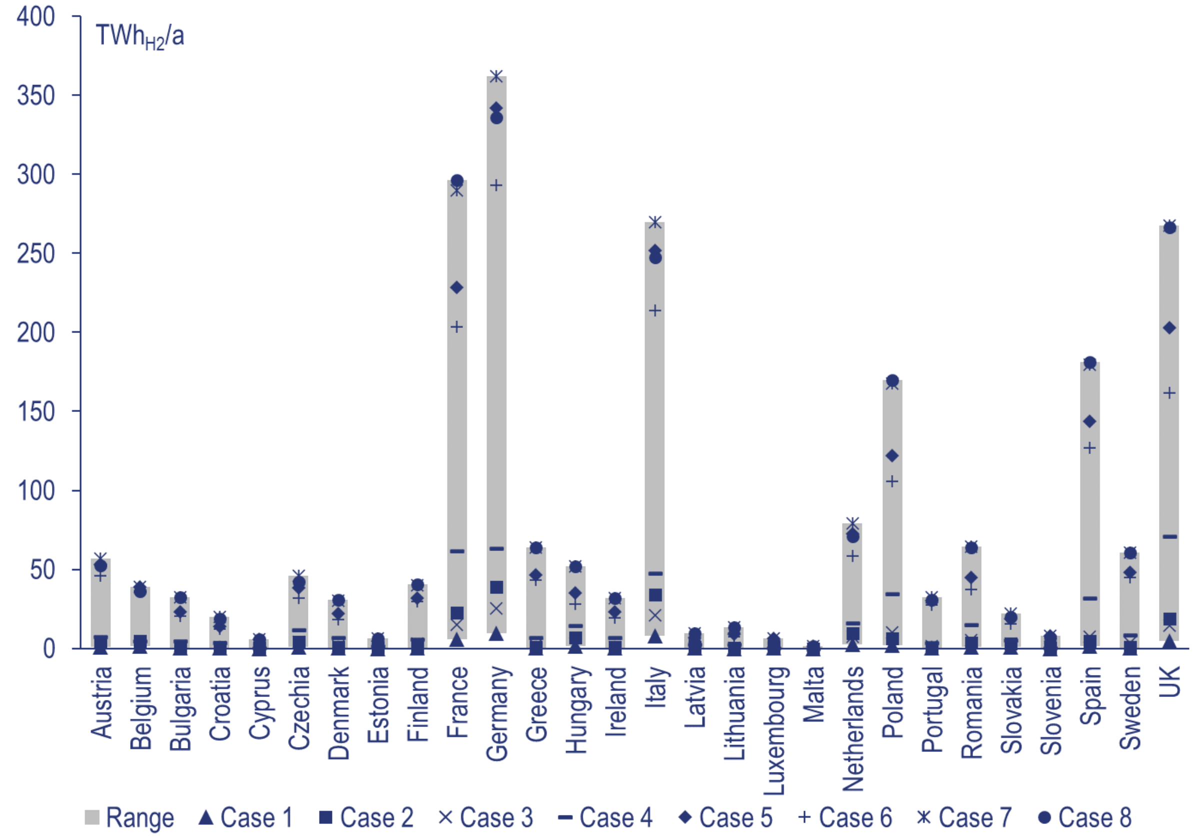


Figure 9: Expected amount of stored hydrogen in underground facilities in selected cases.

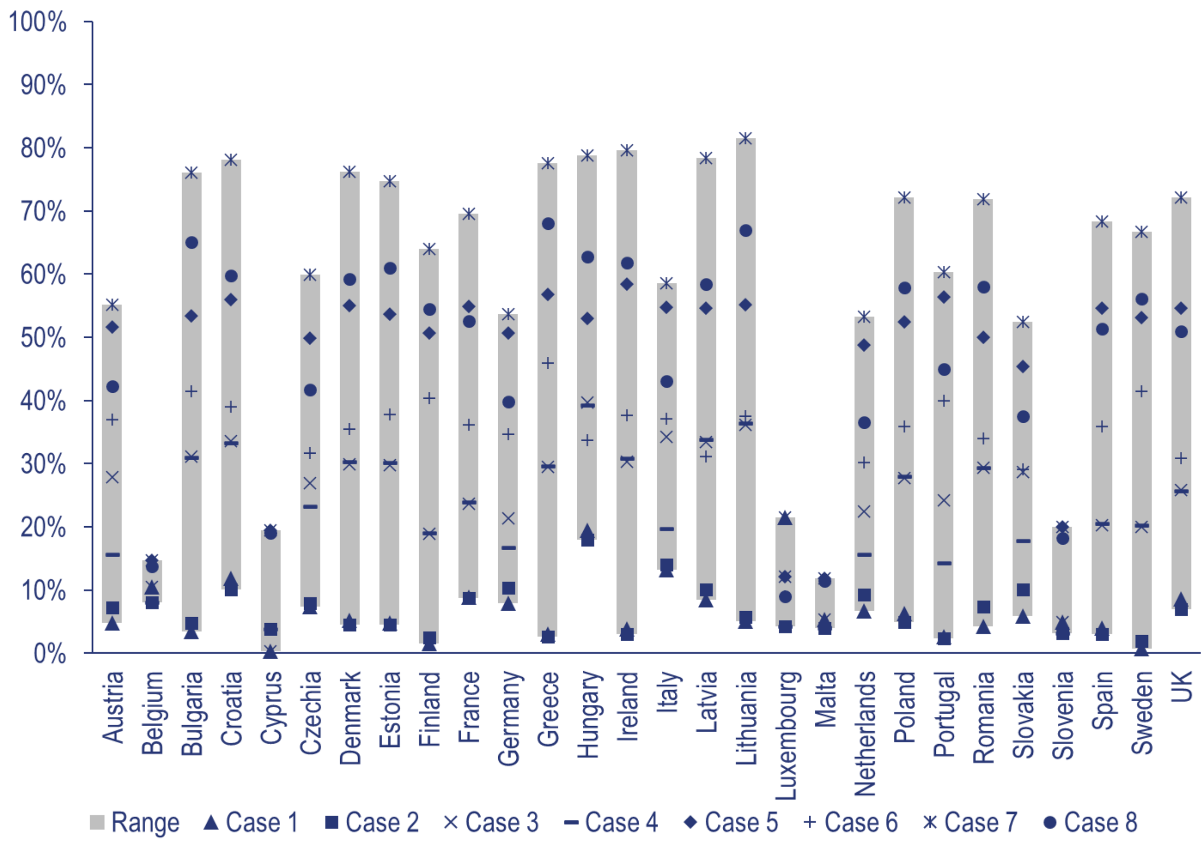


Figure 10: Amount of stored hydrogen as a share of overall hydrogen demand in selected cases.

Nevertheless, underground renewable hydrogen storage is operated on a seasonal basis in all cases and in all countries. As presented in Figure 11 the highest number of full cycle equivalents can be observed in cases with high hydrogen demand and variable supply (Cases 5 to 8) of up to 8.5 cycles (or 43 days[12]). In contrast, in Cases 1 to 4 the underground storage operation is characterized by ca. one cycle per year regardless of hydrogen demand and storage capacity. This means that low hydrogen demand excluding the power sector and constant hydrogen supply reduce the fluctuation of in storage filling level significantly.

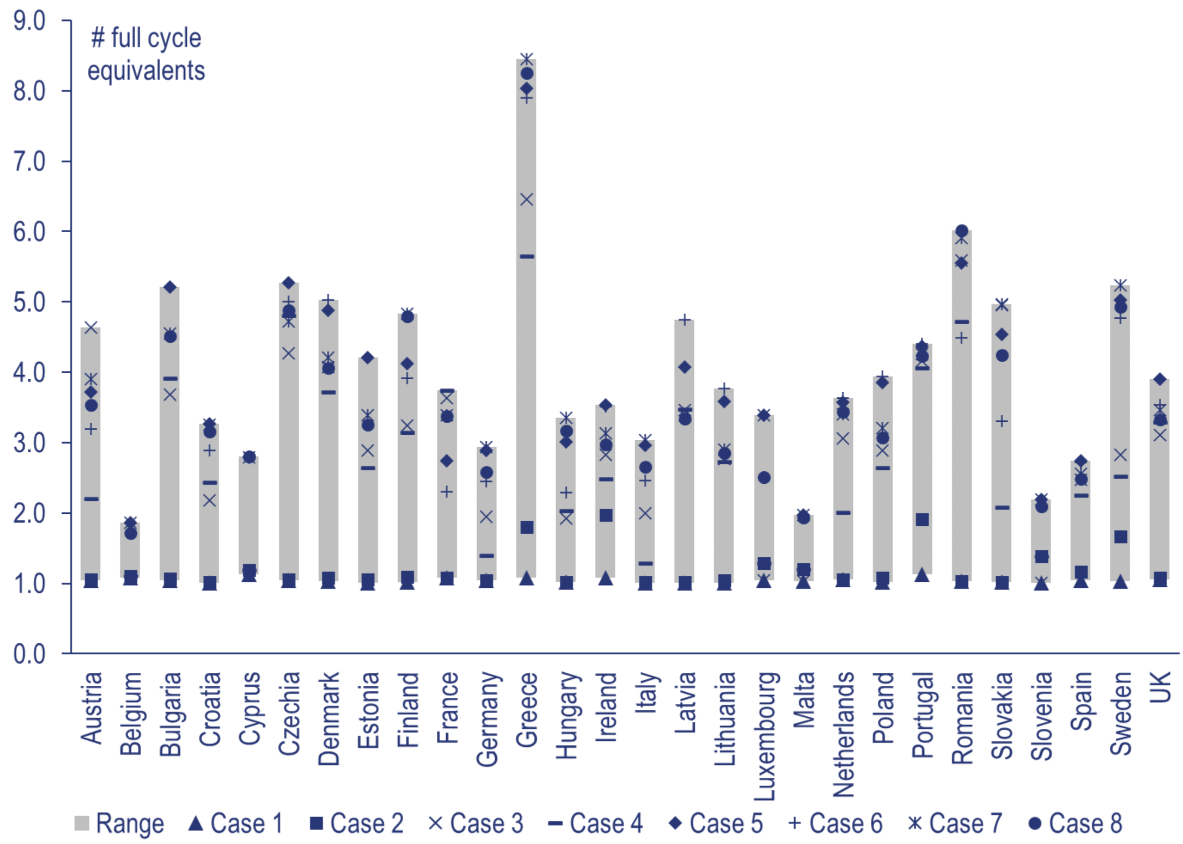


Figure 11: Number of full cycle equivalents of underground hydrogen storage in selected cases.

[12] Calculated as average number of days per full cycle equivalent, i.e. by dividing 365 days per year by the number of full cycle equivalents. This figure corresponds to an average time for hydrogen remaining within the storage.

4. Conclusions

The preliminary analysis of expected techno-economic requirements for underground renewable hydrogen storage reveals significant energy storage needs across Europe. The required long-term hydrogen storage capacities range between 40 to 700 TWh_{H2} in EU-27 and the UK for eight different cases under the predefined assumptions of this report. The major factors influencing the storage needs are:

- general direct hydrogen demand levels in end-user sectors including transport (i.e. FCEVs), buildings (H_2-based heating) and industry sectors (including H_2 use as feed-stock),
- hydrogen consumption in the power sector mainly dependent on relationship between direct electricity demand, renewables feed-in and availability of flexibility measures other than electrolysis such as pumped-hydro storage or demand side management,
- as well as supply pathways, i.e. variable hydrogen production based on domestic fluctuating renewable power from wind and solar vs. constant supply such as imports or production based on steam methane reforming (potentially combined with carbon capture and storage technologies).

In particular, the six big economies with the largest energy demand in Europe including Germany, France, Italy, the UK, Spain and Poland would account for 75% of the overall storage capacities in Europe. Therefore, from the system perspective, these countries are potential candidates for more detailed country-specific case studies in Work Package 8 of the Hystories project. This supports the Hystories' preliminary choice of case study countries: Germany, France, Spain and Poland in Work Package 8.

Based on the long-term assumption of climate neutrality in Europe the underground renewable hydrogen storage would be operated on a seasonal basis with 1-9 full cycle equivalents regardless of hydrogen demand and storage capacity in all countries. Moreover, ca. 8%-60% of the overall annual hydrogen demand in Europe (or 40-2,200 TWh_{H2}/a) could be stored in underground facilities. In this case, the ratio between storage capacity and input and output capacities is high (170-4,300 and 140-1,600, respectively) in comparison to other energy storage technologies. Nevertheless, the absolute electrolysis capacity for variable hydrogen production in Europe amounts to ca. 200-2,200 GW_{el} in the long-term under the assumptions of this analysis. Based on the data derived from a previous study "Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure" conducted for the European Commission the technical potential for intermittent renewable electricity is higher than the expected power and hydrogen demand in EU-27 and many European countries.

However, it is important to mention that the results of this analysis represent only rough estimates as a first input for further work in other WPs of the project. A more detailed analysis based on sophisticated energy system modelling taking also economic considerations into account will be conducted in Task 5.5 and 5.6 of this Work Package. Hence, the outcome in this report can only be interpreted as the technical potential for EU-27's underground hydrogen storage needs.

5. Abbreviations

a	Annum or year
BEV	Battery electric vehicles
CHP	Combined heat and power
EU	European Union
FCEV	Fuel cell electric vehicles
GHG	Greenhouse gas
h	Hour
H_2	Hydrogen
PV	Photovoltaics
UK	United Kingdom
WP	Work Package

6. References

Trinomics/LBST/E3M, 2019. Impact of the use of the biomethane and hydrogen potential on trans-European infrastructure. September 2019.

Hystories project consortium

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