Picturing the value of underground gas storage to the European hydrogen system

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Foreword

Dear reader,

Gas Infrastructure Europe (GIE) is glad to present to you its new study *Picturing the value of underground gas storage in the European hydrogen system.*

Hydrogen storage is an essential element of an integrated energy system and hydrogen economy. While the public's attention has mainly been on hydrogen supply and transmission infrastructure in recent years, the European Commission has recognised in its Hydrogen Strategy[1] the needs for underground hydrogen storage to balance and ensure the resilience of a future energy system that relies significantly on renewable energy sources. Even though the task of storing energy on a large scale is not new in itself, the higher penetration of intermittent energy sources will push hydrogen storage facilities to play an even more pronounced role.

On the supply side, the need for large-scale storage could be explained by higher hydrogen supply variability driven by intermittent renewable electricity production. On the demand side, this is because of the increase in electrification and the subsequent need to meet higher electricity demand peaks created by residual load. To help present our assets as part of the solution and prepare the ground for investment and political decisions, an overview showing the potential that underground gas storage has in this respect was paramount.

This study builds on the updated proposal for the European Hydrogen Backbone, a vision for a pan-European dedicated hydrogen network, to which many of our members have contributed. We extend this vision by providing an initial outlook into the hydrogen storage needs across Europe, in terms of capacities and services, as well as a broader discussion on repurposing and retrofitting possibilities, geographical availability, and the type of flexibility required in the future markets.

[1] European Commission, A hydrogen strategy for a climate-neutral Europe, 2020.

GIE represent the interests of European gas infrastructure operators active in transmission, storage, and regasification via liquified natural gas (LNG) terminals. Our 68 members work and innovate with renewable and low-carbon molecules, including hydrogen. Today, we handle more than 20% of all of the EU's primary energy consumption though our assets. We believe that by 2050, the gas infrastructure will be part of the new innovative energy system's backbone, allowing EU citizens and industries to benefit from a secure, cost-effective, and sustainable energy supply.

If hydrogen is to reach critical mass, we need to get started now on storage as an enabler of substantial hydrogen demand and regional pipeline networks by 2030. Our members are investigating the feasibility of their storage assets and developing numerous pilot projects. Identifying emerging business models and developing regulatory principles and a Europe-wide cooperation along the whole value chain, including with new stakeholders and participants, will be key drivers of this success.

This report, commissioned by GIE, was developed by Guidehouse, with contributions from Gas Storage Europe (GSE) members. We look forward to discussing our findings and recommendations with you in the coming weeks and months!

Torben Brabo

President of GIE and Senior Vice President at Energinet

Executive summary

Large-scale, underground hydrogen storage is indispensable to the development of the European hydrogen market and will become an important part of the future decarbonised energy system. As in today's energy system, supply and demand balancing will be required on all timescales (hourly, daily, weekly, and seasonal). The overall energy system (electricity, gases) designed to meet the ultimate objective of the energy transition—net zero emissions by 2050 at the lowest cost to society—will also have to be optimised and secure. Underground gas storage will be a key enabler for all these objectives, as it already provides these benefits to the energy system. Compared to its current use, the role of underground gas storage will be even more pronounced to ensure the resilience of the energy system as a whole. On the supply side, this is mostly due to higher (green) hydrogen supply variability driven by intermittent renewable electricity production from the sun and wind. On the demand side, this is because of the sheer volumes (especially for industrial use) and demand variability from increasing electrification and the related need to meet higher electricity demand peaks created by residual load.

If hydrogen is to be deployed at scale, a substantial deployment of storage will be needed as well, requiring a better understanding of the specific storage needs. These hydrogen storage needs will be determined by an overall sector coupling equation. Developments in hydrogen supply and demand as well as interrelations with other sectors (power, transport, heating, cooling) and the sectors' ability to use other flexibility tools (batteries, heat and cold storage, pumped hydropower, etc.) will determine the specific hydrogen storage requirements. When hydrogen production is expected to follow intermittent renewable sources, highly flexible storage is required in addition to the large-scale seasonal volumes. Similarly, if hydrogen is used for power system balancing (short term and seasonal) and heating (directly or indirectly), substantial storage capacities with high flexibility will be required. A whole system adequacy exercise should be performed for electrical and gas systems to allow for the efficient use of energy networks, including storage. Both storage capacities and operating profiles need to be investigated.

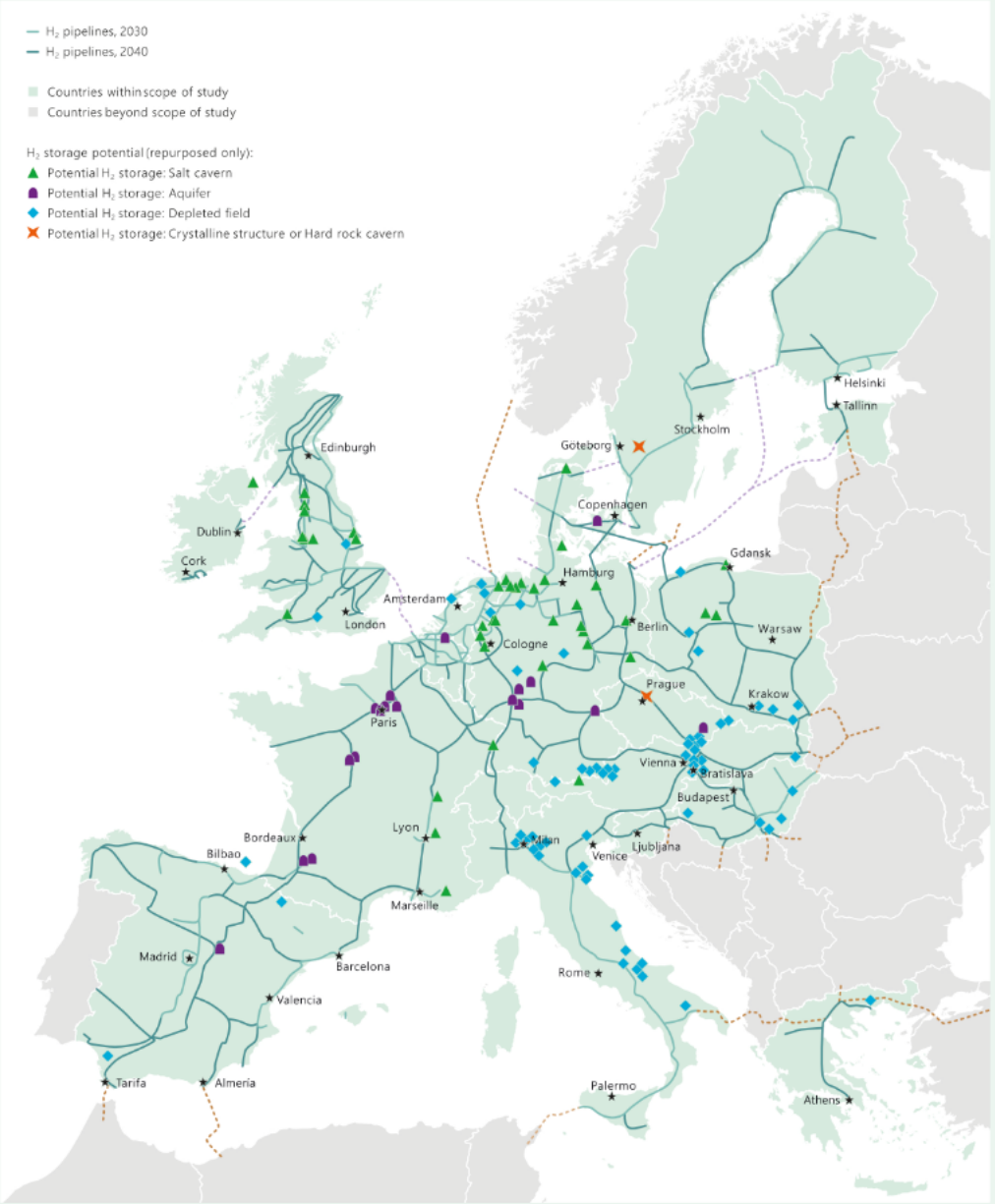
In the early stages of hydrogen market development (up to 2030), demand will likely be concentrated around cluster areas (hydrogen valleys) that will initially mostly manage their supply locally. Underground hydrogen storage will be an integral part of these valleys, helping to significantly improve the economics of the emerging hydrogen infrastructure. In some places, underground storage sites for hydrogen might be repurposed or new ones developed even before the arrival of the European Hydrogen Backbone (EHB). Alternatively, hydrogen blending in storage assets is an option. This option comes with the need to either de-blend the two gases upon withdrawal or to accept a different gas purity standard. By 2030, the EHB could start to interconnect the first valleys into hydrogen regions, both intra-country and cross-border. These developments can also support the large-scale integration of renewables in these regions, particularly offshore wind, with hydrogen storage as a critical component.

As the transition continues and hydrogen supply and demand grow, the hydrogen valleys will evolve into an interconnected hydrogen network, as shown by the EHB initiative (after 2030). More natural gas storage will be repurposed for hydrogen, and the interconnectivity of the network will enable storage further away from hydrogen supply and demand to be used. Hydrogen might also begin to be used in heating (directly or indirectly) and to help meet peaks in electricity demand, beyond the mostly industrial (and transport) uses in the early transition. These uses would alter the demand profile for hydrogen. Peaking would require flexible storage to balance the variation in renewable electricity production, and heating would emphasise the larger need for seasonal storage. The overall hydrogen infrastructure, including storage, will enable a better hydrogen price convergence between the interconnected regions and the already established hydrogen valleys.

Our first-order estimation of hydrogen storage capacity requirements for the 21 countries covered by the EHB shows the need for around 70 TWh of hydrogen storage in 2030, growing to around 450 TWh of hydrogen storage in 2050. All underground storage types will need to be utilised, both for capacity and geographical reasons. Repurposing and developing new storage sites will be required going forward. The decision for repurposed versus new development will be driven by a variety of factors including the development of hydrogen and natural gas storage needs over time, the availability of the storage, and the individual suitability of the storage site. From a physical point of view, hydrogen, due to its lower energy density compared to natural gas, needs about four times higher storage volumes to store an equivalent energy amount.

The European Hydrogen Backbone and underground hydrogen storage analysis for 2030–2050 (repurposing potential)

Gas Infrastructure Europe



European Hydrogen Backbone initiative and Gas Infrastructure Europe 2021, supported by Guidehouse

Hydrogen storage in salt caverns is a low-hanging fruit and current research shows that porous structures (depleted gas fields, aquifers) are showing fair potential to cover further storage needs for pure and blended hydrogen. Given the geographical availability and expected capacities required, we will need all types of underground storage for hydrogen. Salt caverns are suitable for large-scale pure hydrogen storage but are limited by their geographical availability across Europe. Depleted gas fields and aquifers are likely to be usable for hydrogen and are present more widely across Europe, so these will need to be utilised as well. Salt caverns (for natural gas storage) are operational in six EU member states and the UK with an estimated working gas capacity of 50 TWh of hydrogen after repurposing. Depleted gas fields and aquifers are used as gas storage in 16 EU member states and the UK with an estimated working gas capacity of 215 TWh of hydrogen after repurposing.

To be ready for substantial hydrogen demand and regional pipeline networks by 2030, we need to start on the storage now. Repurposing can take anywhere between 1 and 7 years and developing new storage assets takes between 3 and 10 years from pre-feasibility to operation. Each existing site must be investigated for its suitability to store pure and blended hydrogen.

Storage system operators have a key role—their experience will be needed. Many of these operators have started to investigate the feasibility of repurposing their assets. Several pilots are testing or planning to test storing hydrogen pure and in various blends in salt caverns, depleted gas fields, aquifers, and hard rock caverns. More field testing and R&D is needed, however. Certain repurposing actions could be standardised to streamline the procedure. Some storage operators have also taken commercial role in the planning of new hydrogen projects.

A clear business case and an enabling regulatory environment need to be present to enable decisions to repurpose or develop large-scale, underground hydrogen storage. Collaboration between supply, demand, infrastructure operators, and regulators will be key. Integrated infrastructure planning including hydrogen storage is necessary for a cost-efficient and timely energy transition in Europe.

Hydrogen storage.
Source: Storengy

1. Background and scoping

1.1 The role of hydrogen

Hydrogen is seen as one of the key elements in the transition to a net-zero greenhouse gas (GHG) emissions energy system in Europe. In its strategic vision for a climate-neutral EU, the European Commission projected the share of hydrogen in the energy mix to grow from the current less than 2% (fossil-based hydrogen) to 13%–14% (green and low-carbon hydrogen) by 2050.[2] This crucial increase is due to hydrogen's potential role in hard-to-decarbonise industry applications (e.g. steel, fertilizers, high value chemicals), heavy duty transport (e.g. marine and aviation), power storage and generation, and, potentially, in building heating. The specific future applications of hydrogen should be carefully analysed, yet a wide consensus believes its role in the net-zero emissions system will substantially increase from the current use.

Hydrogen could also become an important means for sector integration by linking the various energy carriers—electricity, heating and cooling, gas, solid and liquid fuels—with each other and other end-use sectors.[3] The future energy system will likely experience larger variability on the supply side, driven by variable renewable sources. Similarly, continuous electrification of demand will create larger electricity demand peaks, especially during cold weather.[4] Hydrogen can play a key role in renewables integration (storing large amounts of energy at times with hig icity generation by the Gas for Climate initiative for the EU27 and the UK.[5] The upward excess supply of renewable electricity generation relative to load can be (partially) stored in batteries and hydrogen (power to gas), and the high electricity demand must be met by dispatchable energy resources—batteries, (hydrogen) gas to power, biomass, or natural gas combined cycle gas turbine with carbon capture and storage (CCS). For both instances, hydrogen storage (short and long term) is indispensable.

Notes

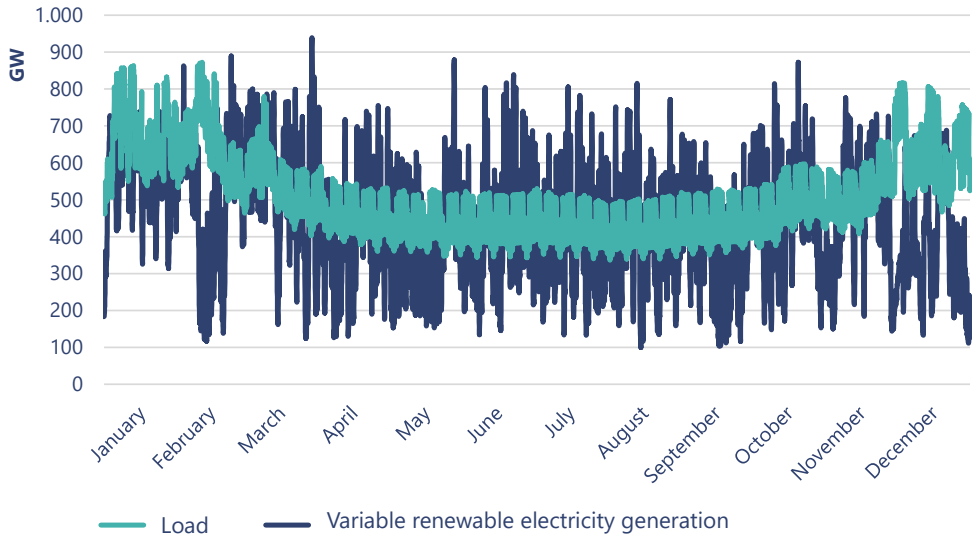
[2] European Commission, A hydrogen strategy for a climate-neutral Europe, 2020. The European Hydrogen Backbone estimates hydrogen demand of 328 TWh in 2030 and 2,110 TWh in 2050 across the EU27 and UK.

[3] European Commission, Powering a climate-neutral economy: An EU Strategy for Energy System Integration, 2021.

[4] See: Kai Kosowski and Frank Diercks, "Quo Vadis, Grid Stability?" 2021; Damien Ernst, "Big infrastructures for fighting climate change," 2020; or Ecofys, "Windless winter weeks," 2016.

[5] Gas for Climate, "Publications," 2021.

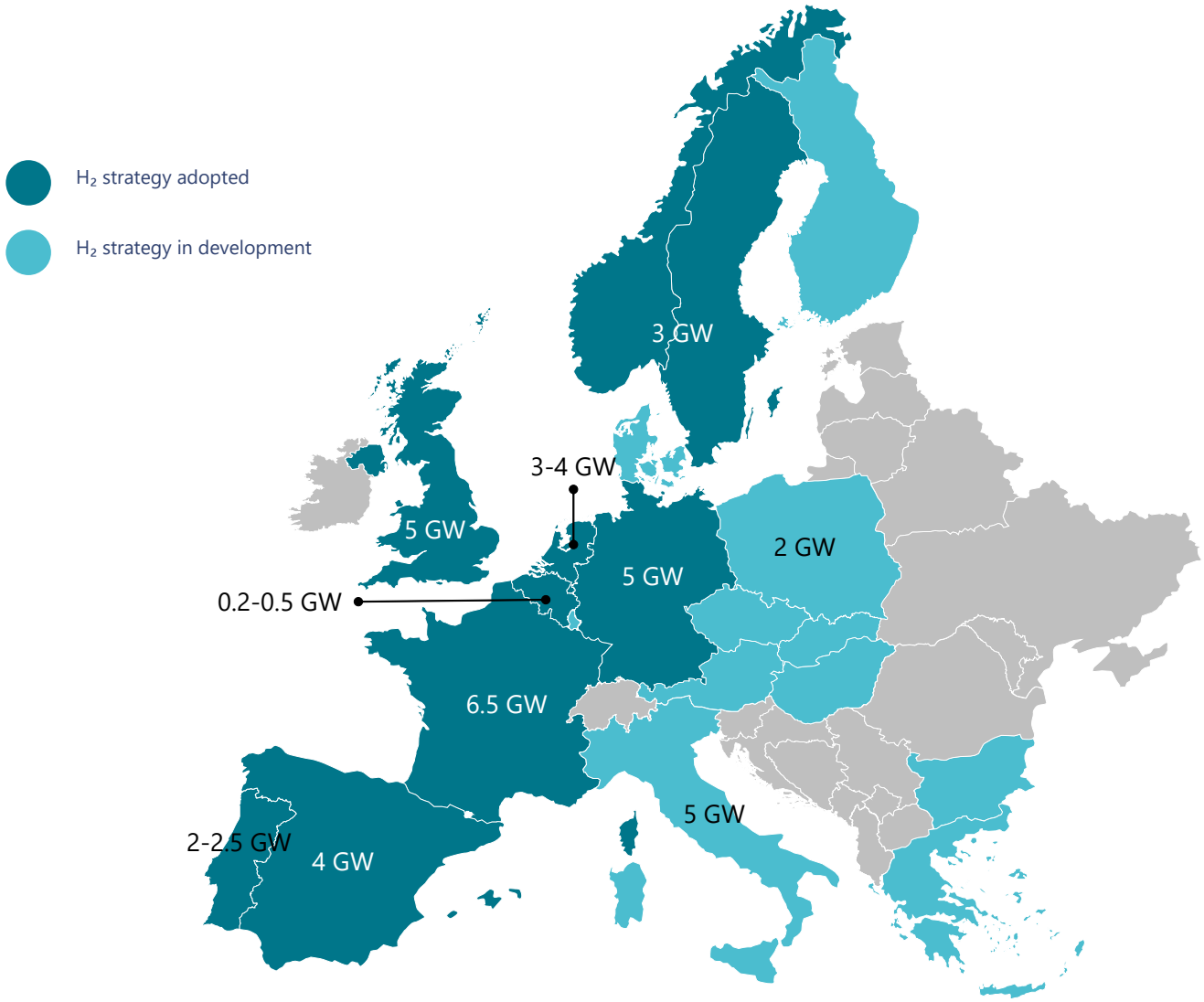
Figure 1 – Hourly variable renewable electricity generation and load, EU27 and UK, 2050[6]



[6] Based on *Ecofys, Gas for Climate: How gas can help to achieve the Paris Agreement target in an affordable way, 2018.* The chart shows the optimal use of the gas scenario to meet a GHG emissions reduction of 95% (compared to 1990 emissions). The modelling looks at the optimal use of gas taking an overall system perspective where the use of renewable and low-carbon gases supplement direct electrification. The main difference to the electrification-only scenario is the use of renewable and low-carbon gases in buildings and the power sector.

The process of developing hydrogen markets in Europe is already taking shape. The European Commission is defining multiple regulatory packages relevant for hydrogen (Delegated Act for Article 27 of the Renewable Energy Directive II, Renewable Energy Directive III, Hydrogen and Gas Market Decarbonisation Package, etc.). The EU Hydrogen Strategy aims to have at least 40 GW_{el} of electrolysis capacity installed in the EU by 2030. National hydrogen strategies announced to date already foresee around 37 GW_{el} of cumulative installed capacity by 2030 (Figure 2; including the UK). A number of countries (Austria, Czech Republic, Denmark, Slovakia, Hungary, Bulgaria, and Greece) are still developing their strategies.

Figure 2 – Planned installed electrolyser capacity in 2030 in EU27 and UK



1.2 Integrated hydrogen infrastructure

Local production and consumption of hydrogen (including storage) will be possible in many cases (e.g. hydrogen valleys), especially in the early stage of hydrogen market development. However, because major hydrogen production areas will not always be close to major centres of demand and to fully realise the benefits of a (financially) liquid hydrogen market, a dedicated hydrogen infrastructure will be required.

This infrastructure has several advantages:

- It can facilitate the export of cheaper green hydrogen from regions with high renewable electricity (RES-E) share and blue[7] hydrogen from regions where large-scale carbon capture and storage is feasible. It can also create better hydrogen price convergence between the interconnected regions and a more attractive cost level of hydrogen for Europe as a whole.
- It provides better means to balance supply and demand, access to storage locations, and more security of supply.
- It allows for system coupling and can support the electricity system supply-demand management on a variety of timescales. By doing so, it can help to better absorb renewable electricity production and store it (by avoiding curtailment).
- In a smart combination with electricity infrastructure, it can help to transmit energy across longer distances and potentially more cost-effectively than (additional) electricity transmission infrastructure alone.

The European Hydrogen Backbone (EHB)[8] describes the value that large-scale, integrated hydrogen transport infrastructure could provide to Europe's future energy system. The EHB's focus is to outline how such a dedicated hydrogen transmission infrastructure could be created in a significant part of the EU[9] between 2030 and 2040. This vision fits well with the EU Hydrogen Strategy and the Energy System Integration Strategy.[10]

Considering all these developments, hydrogen storage has been comparatively understudied. In a scaled-up hydrogen market and advanced climate scenarios, large-scale hydrogen storage plays a critical role. Both the gas (hydrogen) and electricity supply and demand variability will need to be managed on all timescales (hours, days, weeks, seasons). Thus, whole system adequacy assessments will likely be necessary. These assessments would reflect the most cost-efficient and secure energy system meeting the climate and other important societal objectives.

[7] There is no uniform definition of blue hydrogen yet available. Generally, blue hydrogen refers to hydrogen production from natural gas combined with carbon capture and storage.

[8] European Hydrogen Backbone, *Analysing future demand, supply, and transport of hydrogen, 2021.*

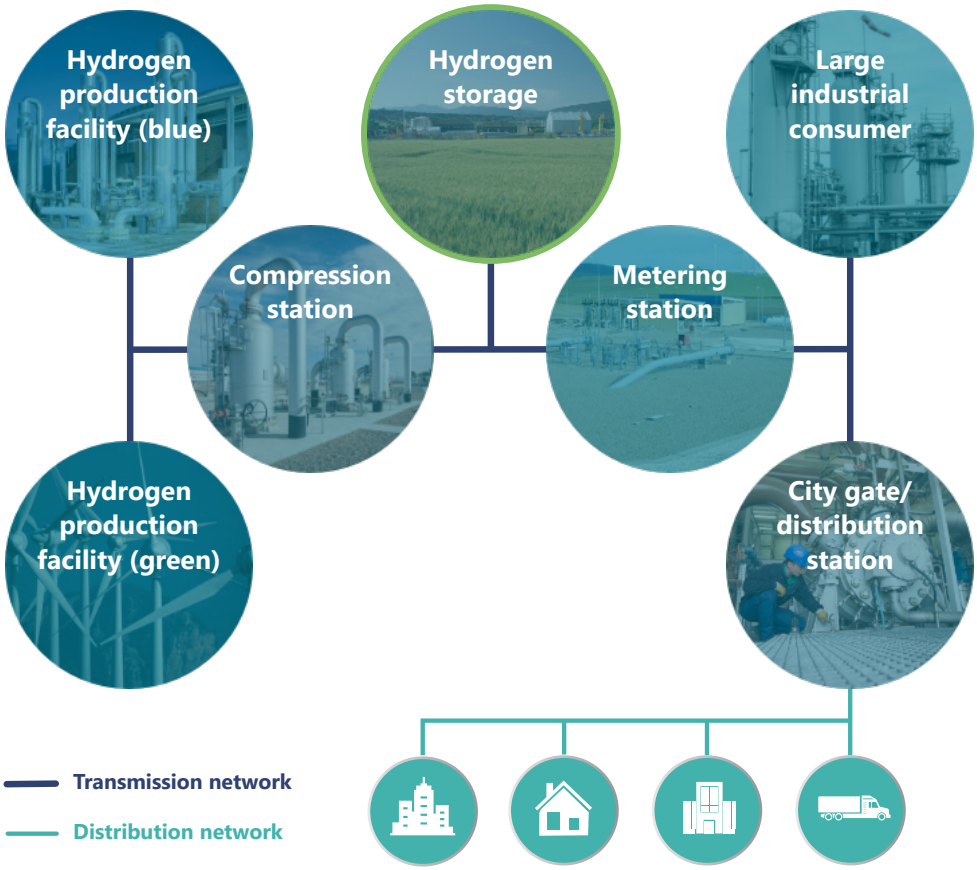
[9] The EHB covers 19 EU member states, the UK, and Switzerland.

[10] The Energy System Integration Strategy foresees dedicated infrastructure for large-scale storage and transportation of pure hydrogen, going beyond point-to-point pipelines within industrial clusters.

The EU has begun work on new legislative proposals for hydrogen and gas decarbonisation packages to enable the development of hydrogen infrastructure, with a delivery date before the end of 2021.[11] These legislative proposals will have to tackle many crucial regulatory questions around horizontal and vertical unbundling of natural gas and hydrogen system operators, regulated asset base regimes, cross-subsidisation, and valuation of natural gas assets when repurposed for hydrogen, to name a few. Most recently, the importance of hydrogen markets and infrastructure, including storage, distribution, and import infrastructure, in a more integrated and flexible energy system was underlined at the 35th European Gas Regulatory Forum (the Madrid Forum).[12]

Figure 3 summarises the infrastructure components required to make a hydrogen network function properly. Hydrogen storage is critical in allowing operators to balance the supply and demand of hydrogen.

Figure 3– Necessary infrastructure components of a hydrogen network[13]



[11] European Commission, *Hydrogen and decarbonised gas market package, 2021.*

[12] European Commission, "35th Madrid Forum," 2021.

[13] Adapted from: Guidehouse, *Extending the European Hydrogen Backbone: A European Hydrogen Infrastructure Vision Covering 21 Countries, 2021.*

1.3 Aim of this paper

This study builds on the most recent discussions and developments towards a dedicated hydrogen infrastructure in Europe—most notably the updated extended proposal for the EHB. It sheds light on the role of hydrogen storage in the energy transition by illustrating its critical role in the scale-up and function of the upcoming European hydrogen markets.

Gas Infrastructure Europe (GIE), as well as its subdivision Gas Storage Europe (GSE), is the largest European organisation of natural gas storage system operators (SSOs). GSE members operate a variety of underground gas storage assets, including depleted oil and gas fields, aquifers, salt caverns, and lined rock caverns. Natural gas storage plays an indispensable role in the current natural gas system by providing flexibility on a variety of timescales, increasing network capacity, and serving as insurance to meet security of supply obligations. SSOs are likely to play a similar role in the emerging hydrogen infrastructure. GIE has commissioned Guidehouse to help develop an initial vision on how its members' assets can play a role in these developments.

This study:

- Provides an initial outlook into the storage needs of the future hydrogen system. It connects the analysis to the updated EHB hydrogen demand forecast and extends the estimations of required storage capacities.
- Summarises the general suitability of all major types of underground gas storage for hydrogen, which is supported by interviews with leading European storage operators.
- Outlines the next steps in the developments of hydrogen storage—be it a clear business case for storage operators to repurpose and develop new hydrogen storage, enabling a regulatory environment for the hydrogen market including storage, or a more detailed analysis of the storage capacities and operational characteristics required to meet the needs of the dedicated hydrogen infrastructure and a future, decarbonised energy system.

Gas infrastructure company Fluxys in Loenhout, Belgium.
Source: Fluxys

2.

The role of underground gas storage in developing the European hydrogen system

In this chapter, we describe the role of natural gas storage in the European energy system today and then explore the role it could have as hydrogen storage in the future energy system.

2.1 Underground gas storage today – how does it operate and create value?

Natural gas has been stored successfully at various scales and time durations for decades in a secure manner.[14] Large-scale, underground storage has been developed in salt caverns, depleted oil and gas fields, aquifers, and lined rock caverns. Underground gas storage provides several key services to the energy system:

- Market value by providing flexibility on all timescales.
- System value by allowing for optimisation in the gas and electricity systems.
- Insurance value by bringing security to the energy system in case of unforeseen events.

These services are further described in the Section 2.2.

Overall gas system balancing on all timescales is performed by combining (depending on their availability) storage, liquefied natural gas (LNG) terminals, linepack,[15] and interconnector capacities.[16] Each national (regional) natural gas system is designed to meet a particular purpose. This purpose depends on the specific demand profiles of the customers and considers the specific local constraints: imports, domestic gas consumption, interconnectedness, availability of storage, or security of supply considerations.[17]

[14] See for instance Perry, K, Natural Gas Storage Experience and Technology: Potential Application to CO_2 Geological Storage, 2005, p. 815-825.

[15] Linepack makes use of the physical volume of gas contained in the pipelines. Variations in the pipeline operating pressure can modulate the volume of gas in the pipeline. This flexibility can be used to manage instant demand variations. Generally, the larger the service area, the more balancing that can be achieved with linepacking; however, it is typically used to meet up to several hours of balancing requirements.

[16] Some storage assets might be exclusively used by the gas transmission system operators for balancing purposes. In many cases, these assets are not subject to third-party access.

[17] The European Commission Regulation on the security of gas supply aims to ensure that all necessary measures are taken to safeguard an uninterrupted supply of gas throughout the EU. Member states are required to develop preventive action plans and emergency plans to deal with crises, and all member states have made sure that gas supplies will be guaranteed to households and other protected customers for a certain period of time, as a minimum, even in the case of a failure of the country's main gas infrastructure. Typically, the government requires that a certain storage volume is held for the security of supply.

Transitioning to a net-zero emissions European system with an increasing share of both electricity and hydrogen, underground gas storage will likely still be needed for bulk and long-term energy storage. In electricity system balancing, pumped hydro storage is limited geographically and its overall capacity is restricted. Other electricity storage solutions like batteries are suitable for smaller volume, short duration storage but are prohibitively expensive for operation with a few cycles per year.

How does underground gas storage operate?

The key defining parameters for storage operation are the cushion gas volumes, working gas volumes, injection rates, and withdrawal rates. Cushion gas refers to the gas permanently stored in the underground structure during the lifetime of the site.[18] Its main function is to maintain the conditions required for adequate storage operation[19] at all times. Working gas is the amount of gas that can be injected into and withdrawn from the storage in one cycle. Injection and withdrawal rates determine the maximum gas flow rate in and out of the asset. In general, the more working gas is withdrawn, the lower the storage pressure and the withdrawal rate.[20] Vice versa, the more working gas is injected, the higher the storage pressure and restrictions on the injection rates. Importantly, storage must be managed within its design parameters, such as minimum and maximum pressures, temperatures, etc., which influence the way a particular storage site can be operated.

Gas storage operators offer a variety of products to serve the different needs of the market. Typically, these come as storage bundles—a combination of working gas volume, injection, and withdrawal capacities with a fixed ratio between these three. Each storage asset (or assets coupled in a virtual storage) has a defined churn rate (i.e. how often can injection or withdrawal occur within a year). SSOs have defined products for a variety of timescales, divided generally into seasonal churn, mid churn, and fast churn products depending on the specific client requirements. Netting of injection and withdrawal requests from customers reduces the actual, physical need for either storage operation mode, which allows for more flexibility to react to the fluctuating supply and demand conditions. Some storage is also operated in a hub/cluster mode, allowing for fast cycle injection and withdrawal services to deliver flexibility to the market.[21]

Seasonal storage products typically have lower withdrawal rates that last for months and are designed to meet seasonal variation in natural gas demand (i.e. higher demand in the winter than summer due to more heating demand).[22] Gas supply has a more steady profile due to both technical and economic reasons. Figure 4 shows the daily natural gas consumption in the EU27 and the UK in 2019. Observe the significant variation between the summer and winter months.

[18] Some of this cushion gas can be recovered during storage abandonment.

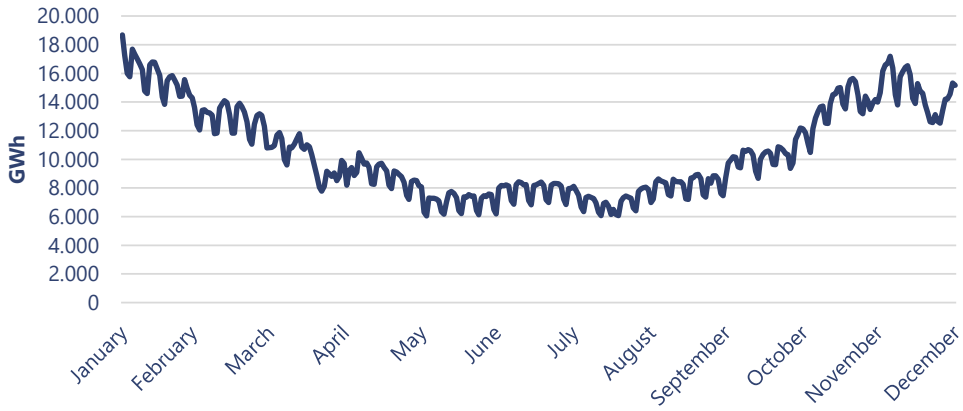
[19] Conditions include the pressure ranges, flow rates, avoidance of withdrawal contamination, etc. Cushion gas is the minimum required volume of gas in the storage to operate in nominal conditions of the installation.

[20] This is a generalised rule. There are examples of depleted fields that can maintain a constant withdrawal rate until the working gas inventory is depleted.

[21] Some sites are then set to injection and others to withdrawal mode.

[22] This variation is mostly driven by residential and commercial building heating demand. With continuous increasing penetration of renewables in electricity generation, the expectation is also for more variability in the gas-fired power demand profile.

Figure 4 – Daily natural gas consumption in the EU27 and the UK, 2019[23]



How does underground gas create value?

Underground gas storage provides multiple benefits to the energy system in terms of modulation (balancing), avoided investments in the electricity and gas infrastructures, and security. Commonly, these are referred to as market, system, and insurance value.

Market value. Underground gas storage provides flexibility to the natural gas (and indirectly electricity) system on all timescales. The traditional use of storage resides in modulating a relatively stable annual supply and highly variable seasonal demand for gas (recall the seasonal demand variation from Figure 4). During periods of lower demand (typically in summer), natural gas is injected into storage, and when demand is higher (typically in winter), the stored gas is withdrawn and added to the supply.

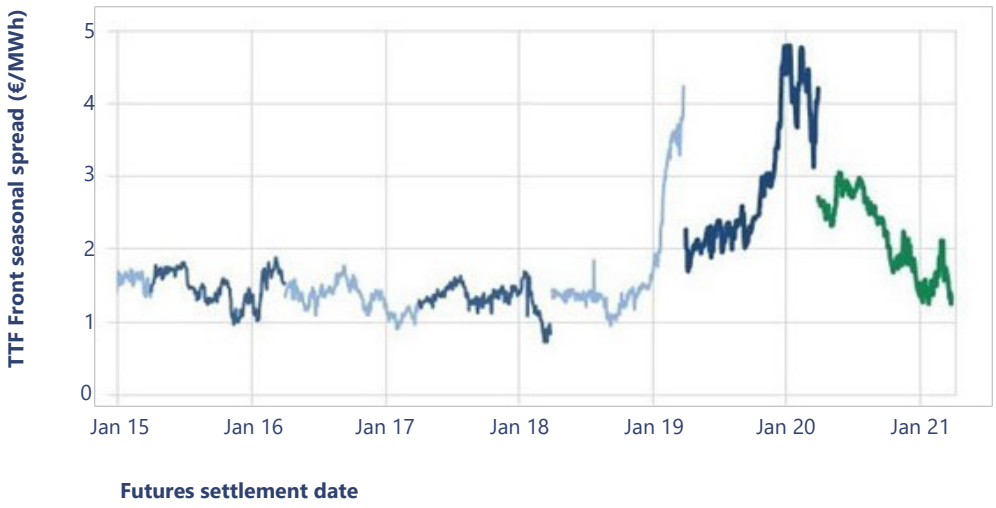
Similarly, given the higher demand in winter, gas prices on the market increase while the prices decline in summer. Storage can help reduce this summer-winter price spread. The created value is partly allocated to SSOs via arbitrage revenues and partly to end users via reduced price spread. Figure 5 shows the seasonal natural gas price spreads in Europe between 2015 and 2021. The price spreads observed in this period have declined substantially from the €4-8/MWh prior to 2010.[24] This decline is likely due to increasing levels of flexibility in the gas and electricity systems as well as declining natural gas consumption (with the peak around 2010).[25]

[23] Guidehouse based on data from ENTSOG, "Transparency Platform," 1 June 2021.

[24] Around €2-4/MWh between 2011 and 2015. Source: Pöyry, "Gas storage market failures: report summary," 2017.

[25] Eurostat, "Natural gas supply statistics," 29 October 2020.

Figure 5 – Seasonal natural gas price spreads[26]



Gas storage also provides flexibility to the energy system on shorter timescales—across hours, days, or weeks. In particular, increasing volatility in gas demand can be observed in the power sector due to the advancing penetration of variable renewable energy resources that require more (gas) peaking power plants or other means of grid energy storage. Gas storage acts as a flexibility tool that can physically guarantee supply to a user (e.g. gas supplier or trader), helping to hedge the supply and price risk on the market.

System value. As an essential function, gas companies need to provide a constant supply of gas throughout the year to the end users. The gas supply chain (and the electricity supply chain as well) is continuously being optimised to deliver this core function effectively and (cost) efficiently. However, gas production cannot easily follow demand, being restricted by limited flexibility in capital cost-intensive production sites and long distance transportation. This lack of flexibility can result in network overcapacity (to meet peak demand) in both gas and electricity systems and problems in gas congestion management.[27] Gas storage creates value by decreasing the need to overbuild the networks, thus preventing additional investments in the gas and electricity infrastructures to meet peak demand. Without this resource, the gas and electricity systems would need to invest in increased flexibility and/or additional generation at an added expense to ratepayers.[28]

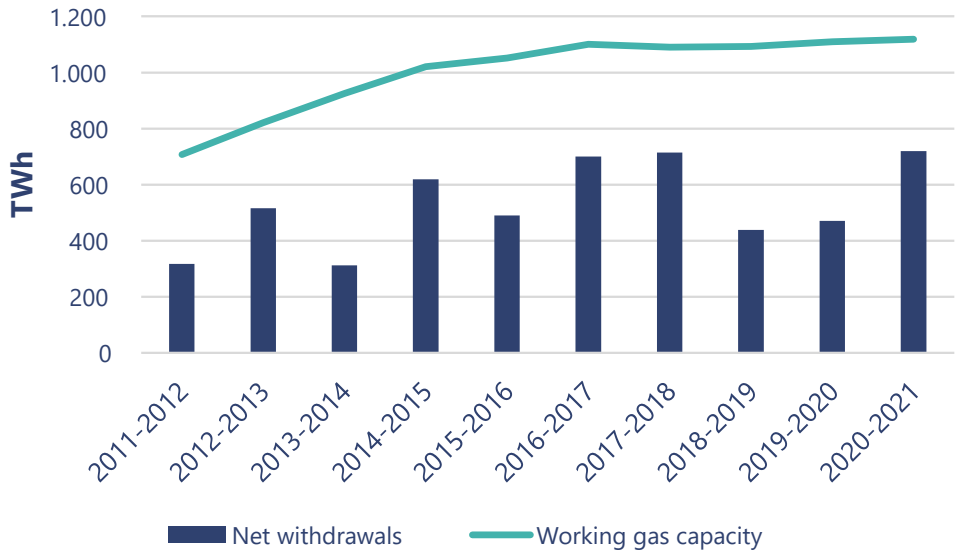
[26] Prices for Dutch Title Transfer Facility (TTF). Source: Timera Energy, "European gas storage value dynamics," 31 May 2021.

[27] Congestion management refers to contractual congestion, which occurs when network users cannot obtain the capacity products of their choice because the capacity demand exceeds the offer.

[28] See for instance Artelys, "Value of the gas storage infrastructure for the electricity system," 2019.

Insurance value. Storage capacities are crucial in meeting the energy needs due to unforeseen events such as a prolonged period of extremely cold weather (e.g. the 1 in 20 winter) or the failure of a part of the energy system. As such, they provide insurance value to the whole energy system. The importance of storage in these situations was demonstrated recently, during the 2020-2021 winter period, where 720 TWh of gas was removed (net withdrawals) from storage facilities in Europe. Figure 6 shows the evolution of the underground gas storage capacity and net withdrawals (withdrawals minus injections) in the winter periods over the past 10 years.

Figure 6 – Net gas storage withdrawals from 1 October to 31 March and total working gas capacity in the EU27 and the UK, 2011 – 2021[29]



In sum, underground gas storage provides three key services to energy systems. Market value is captured in market pricing and results in a reduction of gas price spreads and benefits to consumers. Additionally, it provides a system and insurance value that creates positive externalities for the energy system (and its users) beyond what is reflected in the market value.[30] Storage will likely provide all of these services to the hydrogen market eventually, although its full value potential will only show in a developed hydrogen market.

Table 1 summarises statistics related to natural gas demand and natural gas storage capacity in the EU27 and the UK.

[29] GIE, "Storage data," AGSI database, 2021.

[30] For more information, see for instance FTI Consulting, *Measures for a sustainable gas storage market, 2018.*

Table 1 – Natural gas demand and storage statistics, EU27 and the UK

Parameter	Value	Unit	Share of average annual natural gas consumption (2014–2019)	Year(s)	Source
Average annual demand	5,724	TWh	100%	2014–2019	Eurostat[31]
Average day demand	16	TWh/day	0.27%	2014–2019	Eurostat
Peak demand[32]	26	TWh/day	0.44%	2019	ENTSOG[33]
2-week peak demand[34]	326	TWh/2 weeks	5.7%	2019	ENTSOG
Total natural gas storage working gas capacity	1,168	TWh	20%	2021	GIE database[35]
Total max storage withdrawal rate	22	TWh/day	0.38%	2021	GIE database

There is almost 1,200 TWh of natural gas storage working gas capacity in the EU27 and the UK, enough to store roughly one-fifth of the annual natural gas demand. The average daily demand at 16 TWh/day could be exclusively covered by storage (max withdrawal rate of 22 TWh/day). Peak demand (daily and over 14 consecutive days) cannot be covered by storage alone; it must be assisted by supply. Historical data shows that storage typically contributes approximately 20% of daily demand during the winter season but delivers up to 60% of daily demand on peak demand days. The numbers presented are a summary of the EU27 and UK natural gas systems, and significant differences in these metrics between countries exist (see Appendix B). The European gas infrastructure works as an integrated system where transmission, cross-border and storage capacities are used to operate the network across borders. The analysis of hydrogen storage presented in this study, derived in part from the current operation of the natural gas system, generalises these indicators on a European level.

[31] Eurostat, "Supply, transformation and consumption of gas - monthly data," 2021.

[32] Largest demand in a single day within a year.

[33] ENTSOG, "Transparency Platform," 2021.

[34] Largest demand on 14 consecutive days within a year.

[35] GIE, "Storage data," AGSI database, 2021.

2.2 Underground gas storage in future – what role will it play in hydrogen developments?

Hydrogen can be stored in many forms, including as a gas, liquid, another substance (e.g. methanol, ammonia), adsorbed to a surface, as a hydride, or in liquid organic hydrogen carriers. However, the only viable method for large-scale, long-term storage to provide balancing, optimisation, and insurance for the electricity and hydrogen grids involves storing gaseous hydrogen in large, underground geological structures. These structures are comparatively cost-effective and have the capability to store the massive volumes required for large-scale hydrogen deployment.

Being the lightest molecule of all, hydrogen has a significantly lower density than methane, meaning higher volumes of hydrogen are required to store the same amount of energy as methane. Hydrogen's energy density at 50°C and 100 bar (assumed average operating conditions for hydrogen storage) is 237 kWh/m^3, roughly 24% that of methane at 982 kWh/m^3 (using lower heating value, LHV). Most likely, the ratios between working gas and cushion gas capacities will be the same for hydrogen as for natural gas. All other things equal, a retrofitted natural gas storage site could hold around 24% of the original energy volumes.[36]

The four major underground gas storage types are depleted gas reservoirs, aquifers, salt caverns, and (with a small share) hard rock caverns. Each of the storage sites is, to a certain extent, a unique geological structure and has been designed to operate within its functional parameters. Table 2 summarises the existing natural gas storage capacity by type in the EU27 and the UK.

[36] Storage sites could be altered or expanded upon while being repurposed to accommodate the storage needs required by the hydrogen markets. This would alter their working gas capacity.

[37] Operational assets as of May 2021. From: GIE database, 2021.

Table 2 – Statistics on underground natural gas storage in the EU27 and the UK[37]

Type of storage	Depleted reservoirs	Aquifers	Salt caverns	Hard rock caverns
Number of sites	80	27	63	1
Total working gas capacity (TWh/%)	792/68%	170/15%	206/18%	0.1/0.01%
Total max injection rate (TWh/day)	6.6	1.4	4.5	0.006
Total max withdrawal rate (TWh/day)	10.7	2.7	8.4	0.008

Globally, hydrogen has successfully been stored in salt caverns at three different locations. Teesside in the UK is the only such site in Europe, consisting of three salt caverns with a total capacity of 1,000,000 m^3. The site has been operational for nearly 50 years, and the hydrogen is used for ammonia and methanol production. In Texas in the US, hydrogen is stored in two separate salt caverns, both for use in the petrochemical industry. Beyond this, a large number of demonstration projects to store hydrogen in salt caverns in Europe are being planned; see Appendix A.1 for more detail.

Pure hydrogen has not yet been stored in any of the other storage types; however, as part of its Underground Sun Storage project, RAG Austria successfully stored a blend of 10% hydrogen, 90% methane in a depleted field. RAG Austria also plans to store pure hydrogen in a depleted field by 2030. STOGIT, OMV, and Enagás are planning to examine a broad range of hydrogen and methane admixtures, up to storing pure hydrogen in a series of field tests. In the 1950s, town gas derived from coal, which consisted of up to 50% hydrogen, was stored in some depleted gas fields in Europe. Given their similarities, successful hydrogen storage in depleted fields is a reason to believe that hydrogen could also be stored in aquifers. Teréga will investigate hydrogen storage in aquifers in its Lacq Hydrogen project.

A lined rock cavern is being developed for hydrogen storage in Sweden, expected to be operational in 2022. A detailed summary of the considerations for hydrogen storage in different storage types can be found in Appendix A.

2.2.1 Hydrogen supply

In contrast with natural gas supply, which consists of large, more or less constant flows from a small number of sources, green hydrogen supply will be more decentralised[39] and, depending on how it is produced, can be constant or intermittent, making it more volatile than natural gas supply. If electrolytic (green) hydrogen production follows variable renewable energy sources, the supply volatility will primarily be hourly, daily, and weekly. The production can also be intermittent if following market signals (i.e. electricity prices). It is possible to decrease this intermittency by utilising hybrid wind and solar resources, adding batteries, connecting to the grid, or connecting to dispatchable generation resources such as nuclear or hydro power.[40]

Seasonal volatility in supply might also occur because of the seasonal variation in wind and solar production. However, because wind production is generally stronger in the winter and solar production is stronger in the summer, regions with both wind and solar resources will likely have lower seasonal supply differences than regions that rely primarily on one or the other. This is referred to as complementarity between solar and wind generation to meet electrical demand. Similarly, the seasonal variation in green hydrogen production would be reduced by deploying hybrid renewable generation fleets.[41]

[38] These include HyCAVmobil by EWE; HyPSTER by Storengy; HyGeo by Teréga, H_2@Epe by Uniper; Green Hydrogen Hub by Gas Storage Denmark; HYPOS by VNG; and HyStock by Gasunie.

[39] There will likely still be large production locations, such as the North Sea or Iberian Peninsula, but comparably, green hydrogen production will be more decentralised than that of natural gas today.

[40] Electrolytic hydrogen produced from non-renewable resources would not be considered green. There will likely be various shades of green if hydrogen gets (partly) production from grid electricity, depending on the local grid and the time of production (due to changing grid GHG emission intensity). In the EU, Delegated Act for the Article 27 of the Renewable Energy Directive II will specify (inter alia) the sourcing criteria for green hydrogen production from grid electricity.

[41] The concept of complementarity is well studied in literature. See for instance: J. Jurasz et al., "A review on the complementarity of renewable energy sources: Concept, metrics, application and future research directions," Solar Energy, Volume 195, 1 January 2020 and Mario Miglietta et al., "Local Complementarity of Wind and Solar Energy Resources over Europe: An Assessment Study from a Meteorological Perspective," Journal of Applied Meteorology and Climatology, Volume 56, 1 January 2017.

Blue hydrogen supply will generally be constant, though in some cases it might follow the summer-winter price spread in the natural gas market (i.e. more blue hydrogen production in summer with low natural gas prices). Price hedging with (natural gas or hydrogen) storage could play an important role.

Ultimately, the supply volatility for any given region will be determined by the amounts of each method of hydrogen production and interconnector capacities.

2.2.2 Hydrogen demand

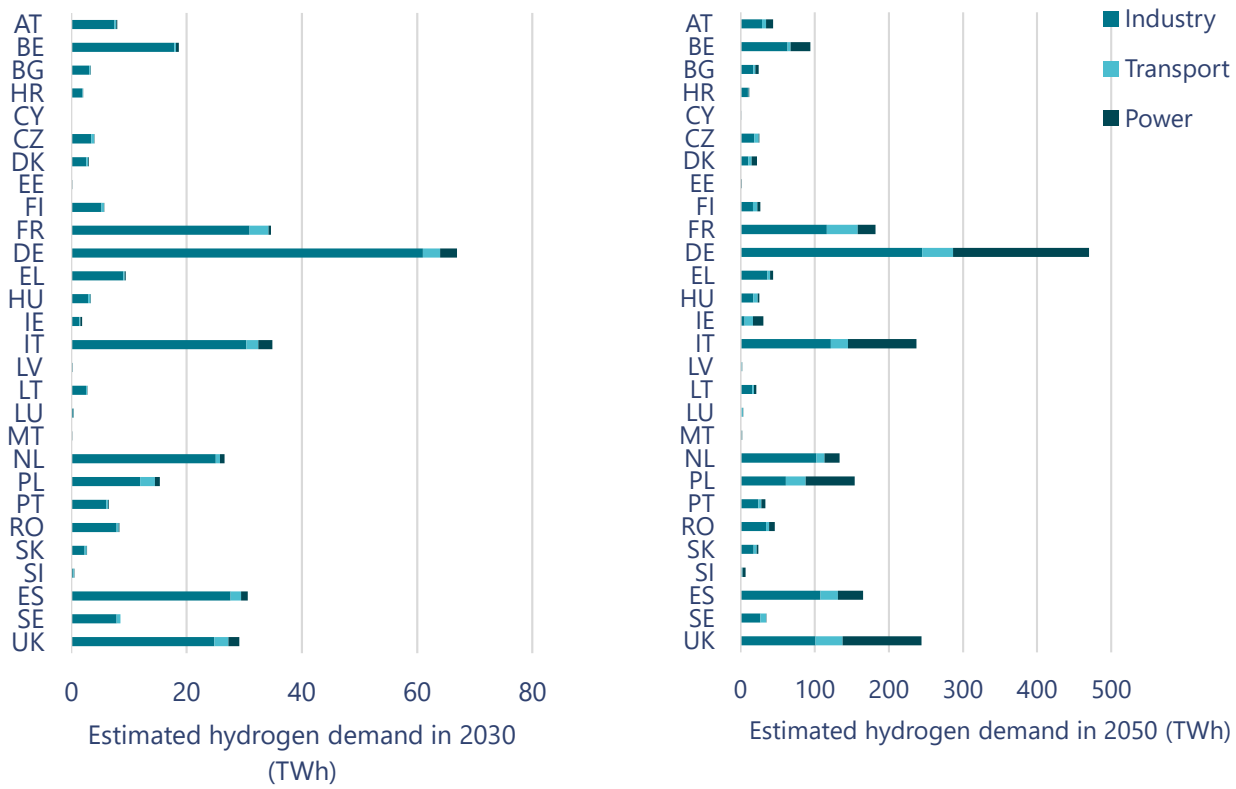
Especially in the first years of the hydrogen market scale-up, most of the demand will come from industrial customers (primarily steel, ammonia, high value chemicals, and potentially industrial heating) and the (synthetic) transport fuels sector, which require continuous, uninterruptible flows of hydrogen. This contrasts with natural gas demand, which is higher in the winter than in summer due to significant demand for heating in buildings.

In the power sector, a massive integration of intermittent renewables will continue. The difference between the electricity production with increasing variability and electricity demand (and demand response measures) will create a significant residual load. The residual load will have to be met with dispatchable electricity sources. Dispatchable power plants could be initially supplied with a blend of hydrogen or natural gas and eventually switch to pure hydrogen (or biomethane).

Towards 2040 and 2050, hydrogen may play a role in building heating as well. To help meet the heat demand, hydrogen could be utilised directly—e.g. in a (hydrogen) gas boiler or as part of a hybrid heating system. However, the EHB initiative projects that hydrogen will only account for 20% of the gas demand in hybrid heat pumps given the advantages of using biomethane in this application. Alternatively, hydrogen could be utilised in hybrid solutions for district heating. Either way, the energy demand for heating will likely be substantially lower as the energy efficiency of buildings improves, and heat pumps become a major heating technology in the future.

Figure 7 shows the forecasted hydrogen demand in 2030 and 2050, as estimated in the updated EHB 2021 study. In the study, industrial hydrogen demand was estimated for the steel, ammonia, and high value chemicals sectors as well as industrial heating demand across all major industrial sectors. Hydrogen demand was also calculated for the production of synthetic fuels for transport, heating in buildings, and load balancing in the power sector. The hydrogen demand for building heating has only been estimated at the EU level and is not used in our analysis for individual countries. For each demand sector, a universal approach was used across member states and calculated for 2030, 2040, and 2050. The demand forecast in each of the analysed countries as calculated in the EHB study might differ from other national forecasts or even national strategies.

Figure 7 – Forecasted hydrogen demand in 2030 and 2050 by country, EHB[42]



2.2.3 Underground hydrogen storage

Underground storage will be critical to any large-scale hydrogen economy. The future hydrogen network could eventually operate in largely the same way as the existing natural gas network (some notable differences are described below). A network of pipelines will connect the hydrogen supply to a variety of customers of different scales and with different demand needs. Hydrogen storage will provide a necessary tool, allowing operators to control the flows of hydrogen to meet the demands of all customers at any given time. As described in Section 2.1 in reference to the natural gas system, hydrogen storage will enable operators to modulate supply and demand, maintain the integrity of infrastructure by keeping pressure and temperature within design parameters, ensure contractually obligated uninterrupted supply, insure against disruptions to supply and/or demand, and defer some additional investments into electricity infrastructure.

[42] European Hydrogen Backbone, *Analysing future demand, supply, and transport of hydrogen*, 2021.

As in today's natural gas system, supply and demand balancing will be required on all timescales—hourly, daily, weekly, and seasonal. Compared to its current use, the role of underground gas storage will be even more pronounced to ensure the resilience of the energy system as a whole. Whereas natural gas systems can partly rely on other storage (e.g. liquefied, compressed aboveground storage) and balancing methods, aboveground hydrogen storage is not feasible for large-scale applications. Hydrogen has a much lower energy density (around 24% of the energy density of natural gas at 100 bar), and it only liquefies at -253°C (at 1 bar, compared to natural gas -160°C at 1 bar). This means that aboveground storage would either have an immense footprint or be very energy-intensive. Dispatchable hydrogen storage for dedicated hydrogen infrastructure in other (synthetic) carriers (e.g. ammonia, methanol) is possible but unlikely, as this would be comparatively expensive and require extensive additional infrastructure.[43]

Alternative ways of storing energy might be complementary to the deployment of underground hydrogen storage. Batteries and pumped hydro are more mature technologies, whereas liquid air energy storage or compressed air energy storage present newer alternatives. All of these could be utilised for the short-term balancing of power supply intermittency, either directly for the electricity system itself or when coupled with green (electrolytic) hydrogen production. Longer-term balancing for both hydrogen and electricity systems will most likely have to utilise underground hydrogen storage given the combined needs for power rating and discharge time.

Due to the decentralised and intermittent production of hydrogen, the hydrogen system will have a greater need for flexible storage that can quickly respond to short-term fluctuations. There will also be seasonal variations in supply, the magnitude of which will depend heavily on the sources of hydrogen in a particular region. An important difference between the hydrogen system and the natural gas system is that most of the hydrogen's volatility comes from supply, and demand will be relatively constant. This may mean a preference to locate hydrogen storage close to hydrogen production rather than demand. Ultimately, the type and exact location of storage sites will likely be determined by the geographical availability of suitable underground structures.

Current underground gas storage is typically capable of switching between injection and withdrawal cycles in an hour or a few hours. Demand created by fluctuations in supply or demand in gas often occur quicker than this, sometimes with only minutes of warning. To bridge the gap between the changes in demand and storage activation time, operators can use storage netting or pipeline linepack. In a natural gas system with hundreds of kilometres of pipes, the linepack can be sufficient to bridge the time gap between the demand and the activation of the storage. However, many systems in Europe are subject to hourly

[43] Renewable methanol requires a source of (biological) CO_2 for its production. Both ammonia and methanol would require reconversion units to produce hydrogen prior to injection to the dedicated hydrogen infrastructure.

balancing due to their relatively low linepack. In such systems, the role of storage in short-term balancing is more pronounced. Hydrogen networks with underground hydrogen storage should be able to meet these flexibility requirements assuming they could be operated in a similar way to natural gas.

Some existing underground gas storage sites will need to be repurposed for hydrogen, while new storage sites might be developed as well. The decision for repurposed versus new development will be driven by a variety of factors including specific hydrogen and natural gas storage needs, availability, and the individual suitability of the storage site. For current gas storage assets to be repurposed, a suitable incentive will be needed. This incentive includes recognising and funding R&D costs associated with the investigation of a site's suitability for hydrogen, a clear regulatory environment (e.g. rules for hydrogen blending), and a positive business case (demand) that would justify the repurposing.

A developed hydrogen network could eventually be functionally very similar to a natural gas network. However, the steps to develop the hydrogen network are not yet completely clear. We provide a vision for developing a role for underground hydrogen storage in the emerging hydrogen infrastructure in the Section 3.

2.2.4 Case study: Hydrogen from variable renewables serving baseload demand

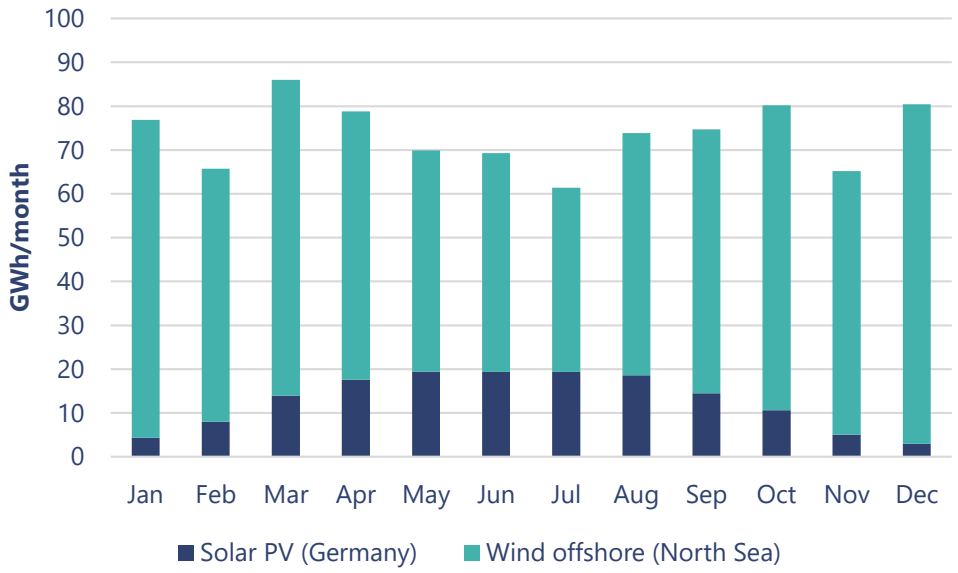
Electrolytic hydrogen can be produced under various operation modes, as discussed in the previous section. One interesting operation mode is when electrolysers are forced to follow variable renewable electricity production but serve customers with constant, uninterruptible demand. This could be an outcome of the EU regulation on Renewable Fuels of Non-Biological Origin, which covers hydrogen and hydrogen derivatives used in the transport sector.[44] The following illustrates the role storage would play in such a scenario.

Consider a refinery that is currently purchasing grey hydrogen (merchant) for its production. The refinery now aims to switch away from grey hydrogen and replace it with green hydrogen. A constant hydrogen demand of 2 tonnes H_2/hour (66.7 MWh H_2; LHV) must be met at all times. If green hydrogen is produced via electrolysis following variable renewable electricity generation, hydrogen storage is an indispensable requirement—to bridge night (solar PV) and wind standstill periods and to manage costs.

[44] Specifically considering the temporal correlation requirement. It is likely that similar requirements will be applied end uses besides the transport sector.

We have investigated the possible storage operation (injection and withdrawal) looking at a combination of monthly solar PV generating profiles for typical locations in Germany and an offshore wind profile in the North Sea. The monthly electricity generation profile for a typical German location and a North Sea offshore wind power plant of the same nominal capacity (150 MW_p, each) is shown in Figure 8. The wind curve dominates the combined production profile; however, solar PV is complementary, especially during summer months when wind output is lowest. This is just one of the many possible configurations of variable renewable generation sources, but the need to cover for the intermittency remains.

Figure 8 – Monthly production profile of a combined offshore wind, solar PV-resource of the same nominal capacity (150 MW_p each)[45]



The electrolyser capacity is set to capture the whole production of the combined solar PV and wind resource (150 MW_p each) in the highest production month (March). The total yearly demand for hydrogen is also met, assuming fully flexible storage helps bridge the times of overproduction and underproduction. This results in an approximate electrolyser nominal capacity of 1.7 times the average monthly demand.[46]

The monthly supply variations and electrolyser capacity determine the storage capacity requirements. The maximum storage injection volume (February) was 7.3 GWh, and the maximum storage withdrawal volume (July) was 9 GWh, which is 15% resp. -18% of the average monthly hydrogen demand of 49 GWh (Figure 9).

[45] Modelled using data from Global Solar Atlas, 2020 and Global Wind Atlas, 2021.

[46] Assuming 66% system energy efficiency, LHV.

Figure 9 – Monthly hydrogen storage injections (+) and withdrawals (-) (average demand is 49 GWh/month)

The case study illustrates one of the likely hydrogen production modes and the key role of storage. Understandably, many other possible setups to deliver on the constant demand exist. Flexible hydrogen storage, however, can decrease the need to oversize the electrolyser vis-à-vis the demand requirements and provide security when a sustained period of low renewable generation occurs.[47] The storage investment costs are estimated at 6% of the electrolyser CAPEX.[48]

[47] Further optimisation will be required to bridge the shorter-term fluctuations in the solar PV and wind electricity production. This could emphasise the storage flexibility needs further (ability to switch between injection and withdrawal cycles); however, it is likely that the overall capacity needs would remain unchanged.

[48] Assuming electrolyser CAPEX of €800/kW_{el}, storage CAPEX of €840/MWh for hydrogen stored (salt caverns). Storage size is approximate to 18% of the maximum monthly hydrogen demand.

Gas storage in Nüttermoor, Germany.
Source: EWE

3.

The European Hydrogen Backbone and underground hydrogen storage

The EHB initiative has developed a proposal for a dedicated pipeline infrastructure across Europe. The latest (2021) EHB report provides insights into potential hydrogen demand, supply, and the different ways of interconnecting these hydrogen sources and sinks.[49] It covers 19 EU member states, the UK, and Switzerland.[50] This study extends the vision to the role of underground storage in the emerging hydrogen market– be it both directly connected to the EHB or not (regional approaches).

Across the 21 countries covered by the EHB, there is 1,096 TWh[51] of working gas capacity in natural gas storage and 4,624 TWh/year[52] of average annual natural gas demand. This translates to a total working gas capacity of 24% of the annual demand. As noted earlier, however, the relationship between storage capacities and natural gas demand varies a lot by country. See Appendix B for the storage capacity and natural gas demand by country. Further, the supply and demand profiles of natural gas and hydrogen are different, leading to potentially different needs for storage capacities relative to demand.

With these considerations in mind, we approximate the need for hydrogen storage from the current natural gas system to arrive at a first-order estimation (see Section 3.3). The hydrogen demand forecast for the 21 studied countries is taken from the updated EHB study.

[49] European Hydrogen Backbone, *Analysing future demand, supply, and transport of hydrogen, 2021.*

[50] Switzerland does not have any underground natural gas storage capacity and its hydrogen demand is not estimated. Rather, it is treated as a hydrogen transit country.

[51] Operational storage capacity as of May 2021. Source: GIE.

[52] Average of 2014-2019.

3.1 Early hydrogen market development (2021–2030

In the early stages of hydrogen market development, demand will likely be concentrated around several (industrial) cluster areas in Europe, also called hydrogen valleys. Initially, these valleys will manage their supply mostly locally. These developments will spur the first need for hydrogen storage, with size and operational demands (i.e. flexibility) depending on their specific supply and demand profile. Where available, salt caverns, either repurposed or new, will likely be developed to serve these valleys.[53] Depleted gas fields or aquifers could also be repurposed for hydrogen storage. Alternatively, blending hydrogen with natural gas in storage assets is an option. This possibility comes with the need to either de-blend the two gases upon withdrawal if pure hydrogen is required by the end users or to accept a different gas purity standard.[54]

Near the end of this period, the EHB could start to interconnect the first valleys into hydrogen regions, both intra-country and cross-border. These developments could also support the large-scale integration of renewables in the regions, particularly offshore wind, with hydrogen storage as a critical component. Most of the existing hydrogen storage assets would start serving broader areas beyond the initial valleys.

3.2 Moving towards interconnected market (2030–2050)

As the transition continues and hydrogen supply and demand grow, the hydrogen valleys and early interconnected regions will evolve into a pan-European hydrogen network. More natural gas storage of all types will be repurposed for hydrogen, and the interconnectivity of the network will enable the use of storage further away from hydrogen supply and demand.

Hydrogen may also be used in heating and to provide flexibility to the electricity system, beyond the mostly industrial (and transport) uses in the early transition. Both of these applications will alter the demand profile of hydrogen. Using hydrogen for peaking in electricity production will require a significant flexible storage capacity because the times of deficit in (renewable) electricity supply (in the overall electricity system) will create a shortage of electricity for green hydrogen production. To bridge these periods, flexible storage will likely be required (blue hydrogen could play a role here). Heating would establish a seasonality to hydrogen demand, which could create a need for seasonal storage.

The overall hydrogen infrastructure, including storage, will enable a better hydrogen price convergence between the interconnected regions and the already established hydrogen valleys.

[53] Other storage technologies such as compressed hydrogen tanks might be used temporarily. These technologies are not explored in this report because they are much more expensive than underground storage, thus unlikely to be implemented widely. Alternatively, it can be assumed that most electrolysers would run in a more baseload mode of operation to eliminate the need of storage.

[54] Several gas storage operators are investigating the possibilities to blend hydrogen with natural gas at all rates (e.g. from 2% to 100%). Understanding these dynamics, especially for porous natural gas storage, is an essential requirement for possible repurposing because residual natural gas could be present in the asset for several years after conversion to pure hydrogen.

3.3 The EHB and underground hydrogen storage

The EHB has illustrated the possible development of a dedicated transmission (pipeline) infrastructure across Europe. The analysis presented in this study complements this vision with the estimated need for hydrogen storage. Hydrogen demand forecasts from the EHB for 2030 and 2050 have been chosen to illustrate the different development stages of the hydrogen market in Europe.[55] [56] The hydrogen storage capacity need estimation (~24% of yearly demand, applied consistently across countries) is derived from the current ratio between the cumulative natural gas demand and underground storage working gas capacity of the studied countries, as an approximation. This assumption is in the same order of magnitude as studies modelling this question implicitly or explicitly.[57]

We make no assumptions on when a particular storage asset might be available or desirable for repurposing. Rather, the **total potential for repurposing** is investigated. The potential hydrogen storage capacity (in hydrogen energy terms) after repurposing is shown for salt caverns only and for all types of underground storage cumulatively. Note that it is shown as a prospective capacity. Further, not all salt caverns, depleted gas fields, and aquifers are expected to be converted for hydrogen because a portion of storage capacity will likely remain dedicated to storing methane and biomethane, and some may be converted to CO_2 storage for CCS applications.[58] Furthermore, some existing gas storage may not be suitable for hydrogen storage. The estimation only considers **repurposing** existing underground gas storage facilities. Immense potential exists to develop additional underground storage capacity of all types, if necessary.

[55] The demand forecast in each of the analysed countries might differ from other national forecasts or even national strategies. The EHB demand analysis has been chosen for the consistency of its approach across all modelled countries. The EHB demand is for hydrogen use in the industry, transport, and power sectors.

[56] The hydrogen infrastructure maps developed for EHB are for 2030, 2035, and 2040. The EHB demand estimation is also available for 2050. While showing the 2030 and 2040 EHB infrastructure in the map that follows, we focus our analysis on hydrogen demand in 2030 and 2050 to evaluate the full scale of the need for hydrogen storage.

[57] TNO estimated 20%-25% of the annual hydrogen demand as the storage need for the Netherlands. Blanco et al. assessed that most advanced climate scenarios model the need for (electricity) storage up to 6% of the total electricity production. Gas for Climate models 7,112 TWh of electricity production by 2050, which would correspond to 426 TWh of storage required. If all of that storage was met by hydrogen, it corresponds to approximately 22% of the EHB 2050 hydrogen annual demand. The North Sea Wind Power Hub Integration Routes modelled between 180 TWh and 270 TWh of annual hydrogen use in the power sector (regional) with a corresponding need for 60 TWh-100 TWh of hydrogen storage, representing an approximately 33%-37% storage versus demand ratio.

[58] Working and cushion gas ratios are kept constant from the current way these assets are operated. The conversion factor used to calculate hydrogen energy capacity from methane energy capacity was determined using the energy densities of methane and hydrogen at 50°C and 100 bar and their respective LHVs. This gives a conversion factor of 0.24 TWh H_2/TWh CH_4.

Our first-order estimation of hydrogen storage capacity requirements for the 21 countries covered by the EHB shows the need for around 70 TWh of hydrogen storage in 2030,[59] growing to around 450 TWh of hydrogen storage in 2050. The analysis is summarised as follows.

If salt caverns are the only underground gas storage type considered for hydrogen storage, the total working gas capacity across existing salt caverns in Europe is insufficient to meet hydrogen demand in 2030 (repurposing potential of 50 TWh of hydrogen versus the need for 70 TWh of hydrogen). Furthermore, salt cavern capacity is limited to only a handful of countries. Considering the limited geographic distribution of the necessary geologic structures, porous rock (depleted field and aquifer) storage sites must also be repurposed for hydrogen to meet storage needs in the future.

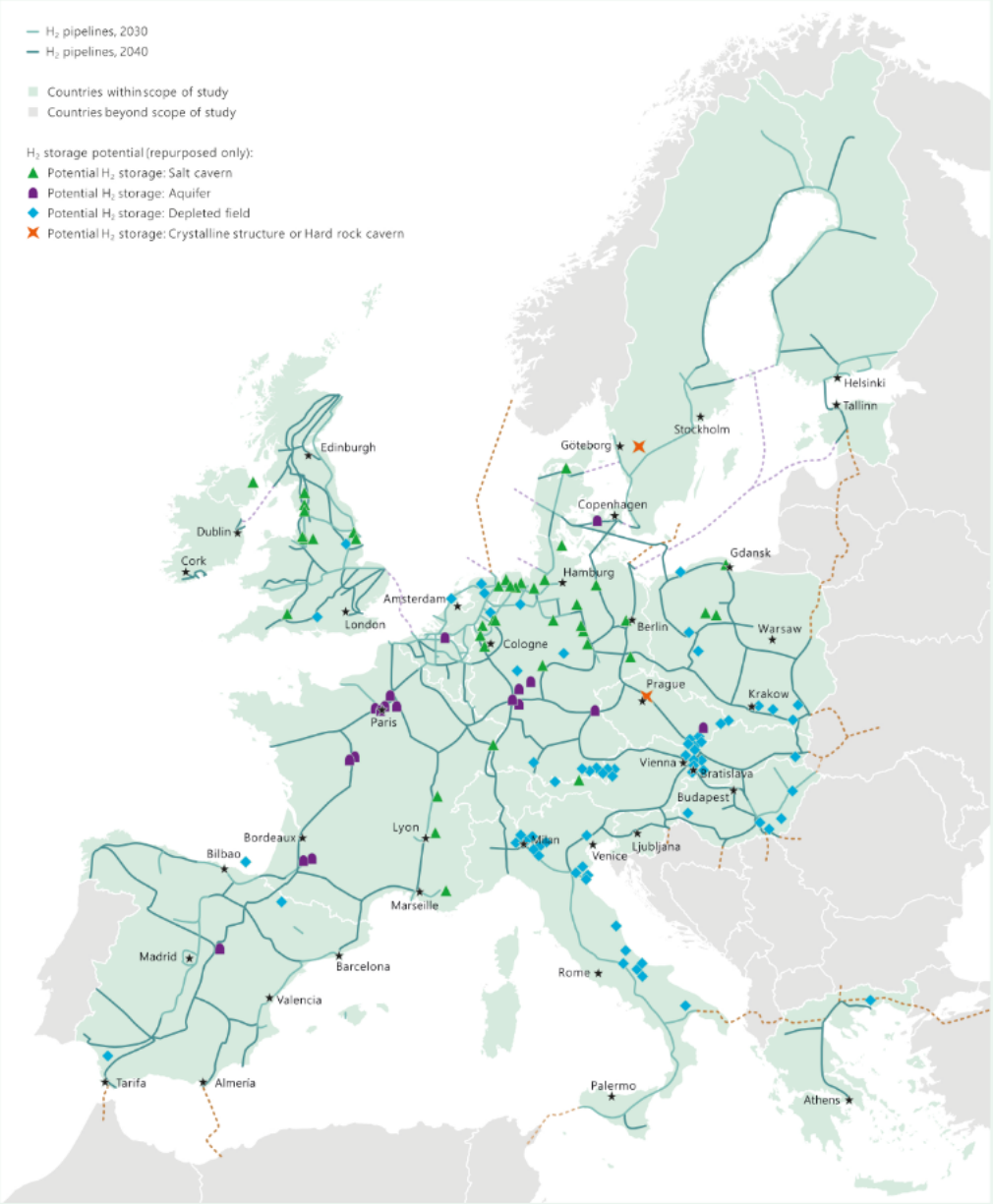
For 2050, the estimated total demand for storage for the assessed countries is around 450 TWh. Even if all current natural gas storage capacity were repurposed for hydrogen, the available capacity (265 TWh) falls far short. This insufficient capacity is mostly caused by the much lower volumetric energy density of hydrogen compared to natural gas, which leads to a decrease in the amount of energy that can be stored in an unaltered storage site. Additional storage sites would need to be developed or existing sites would have to be expanded.[60]

[59] For 2030, our storage needs estimate might be on the higher side because of the flatter profile of the demand applications expected in that period (mostly industrial) and the lower resulting need for flexibility. As hydrogen use will expand significantly to the power sector, and possibly the heating sector as well, the need for flexibility will increase and so will the need for large-scale storage. In both cases, a lot of the flexibility need will be on the supply side from electrolysers (partly) following intermittent renewables. A pan-European hydrogen infrastructure will require large-scale storage to function effectively and efficiently. Finally, the specific flexibility needs and technical limitations will determine the number of cycles that will be performed in each storage site. The number of cycles required or feasible, will co-determine the total capacity of storage required.

[60] As noted earlier, depending on the local specifics, underground storage sites could be expanded upon when being repurposed for hydrogen (or later), which would increase the storage capacity.

The European Hydrogen Backbone and underground hydrogen storage analysis for 2030–2050 (repurposing potential)

Gas Infrastructure Europe



European Hydrogen Backbone initiative and Gas Infrastructure Europe 2021, supported by Guidehouse

Table 3 – Estimated need for hydrogen storage in EHB focus countries [TWh][61]

The hydrogen demand forecast in each of the analysed countries might different from other national forecasts or even national strategies. The EHB demand analysis has been chosen for the consistency of its approach across all modelled countries. Our estimations of the hydrogen storage needs might differ in a similar way.

Country	Hydrogen demand 2030[62]	Hydrogen demand 2050	Hydrogen storage need 2030[63]	Hydrogen storage need 2050	Potential hydrogen storage capacity–salt caverns	Potential hydrogen storage capacity–all types
Austria	8.0	43.8	1.9	10.4	0.0	22.9
Belgium	18.7	94.3	4.4	22.3	0.0	2.2
Czech Republic	4.0	25.4	1.0	6.0	0.0	10.4
Denmark[64]	3.1	22.3	0.7	5.3	1.3	3.3
Estonia	0.1	1.8	0.0	0.4	0.0	0.0
Finland	5.7	26.7	1.4	6.3	0.0	0.0
France	34.7	182.1	8.2	43.1	2.5	31.9
Germany	66.9	470.0	15.9	111.4	39.5	61.4
Greece	9.4	43.9	2.2	10.4	0.0	0.0
Hungary	3.3	25.1	0.8	6.0	0.0	16.8
Ireland	1.9	30.7	0.4	7.3	0.0	0.0
Italy	34.9	237.1	8.3	56.2	0.0	47.1
Luxembourg	0.3	2.9	0.1	0.7	0.0	0.0
Netherlands	26.6	133.4	6.3	31.6	0.9	34.6
Poland	15.3	153.8	3.6	36.5	2.2	9.3
Slovakia	2.7	24.0	0.6	5.7	0.0	12.0
Slovenia	0.5	6.6	0.1	1.6	0.0	0.0
Spain	30.6	165.4	7.3	39.2	0.0	8.2
Sweden	8.5	34.7	2.0	8.2	0.0	0.02
UK	29.1	244.2	6.9	57.9	3.7	4.8
Total	**304.5**	**1,968.1**	**72.2**	**466.4**	**50.0**	**264.7**

[61] Data for natural gas working gas capacities are taken from GIE datasets for all operational storage as of May 2021.

[62] European Hydrogen Backbone, *Analysing future demand, supply, and transport of hydrogen, 2021*. The demand is for hydrogen use in industry, transport and the power sector (both 2030 and 2050).

[63] Hydrogen demand multiplied by current ratio of natural gas storage to natural gas demand (average ratio of the studied countries).

[64] Potential hydrogen storage capacities in Denmark provided by Gas Storage Denmark.

It is too early to predict how much of the existing underground gas storage capacity will be converted for hydrogen with a high degree of certainty. However, if the future hydrogen system requires around the same capacity of storage relative to demand as observed for natural gas today, we will need both repurposed natural gas storage and new (hydrogen) storage. Furthermore, storage operators interviewed for this study estimated that repurposing could take anywhere from 1 to 7 years. It is highly unlikely that such a significant portion of existing natural gas storage will be converted within 9 years given the time required for conversion and the remaining need for natural gas storage to meet the 2030 storage requirements. Therefore, next to the repurposing existing sites, new sites should be developed for hydrogen storage in both the short and long term. All storage is limited by its geographical availability, so the choice between one type or another will be determined by local circumstances.

Regional approaches, where storage capacities are linked to the EHB and operate in coordination to serve larger geographical areas across national borders, could help optimise storage capacities. The need for such approaches is further emphasised by the likely competition for underground storage assets from biomethane and potentially, CO_2. Whole system adequacy planning for the gas (natural gas, biomethane, hydrogen) and electricity systems will be critical in determining the optimal deployment of hydrogen storage capacities across Europe.

Energy infrastructure operator Snam

Source: Snam Rete Gas

Appendix A.

Underground storage of natural gas and hydrogen

Table 4 summarises the important characteristics of the four main underground gas storage types and their general suitability for storing hydrogen. Following the table is a more thorough explanation of each type. It is difficult to generalise findings for underground storage because each one's individual characteristics depend heavily on its specific geological characteristics. Every asset must be assessed individually to determine its compatibility with hydrogen. Most of the data points in Table 4 are based on the way current natural gas storage is operated or on estimations.

Table 4 – Summary of the suitability of underground storage types for hydrogen[65]

Storage type	Depleted field	Aquifer	Salt cavern	Lined rock cavern
General suitability for hydrogen	Site-specific	Site-specific	High	High
Typical type of operation[66]	Seasonal	Seasonal	Peaking	Peaking
Typical number of cycles per year[67]	1-2	1-2	10[68]	10
Estimated facility working gas capacity (TWh H_2)[69]	0.03-14.29	0.05-3.23	0.01-4.12	0.04
Working gas capacity/Total gas capacity	50%-60%	20%-50%	70%	70+%
Depth	300 m-2,700 m	400 m-2,300 m	300 m-1,800 m	1,000 m
Operating pressure	15-285 bar	30-315 bar	35-210 bar	20-200 bar
Cost of development (relative)	Low	Low	Low	High
Cost of operation (relative)	Low	Low	Medium	Medium

[65] GIE database, SSO interviews, A.S Lord et al., *Geologic storage of hydrogen: Scaling up to meet city transportation demands*, 2014.

[66] Seasonal storage sites typically take months to complete a full injection and withdrawal cycle, so they are normally used to meet seasonal variations in demand. Peaking storage can complete full injection and withdrawal cycles in days or weeks, so they are typically used to meet hourly, daily, and weekly variations in demand. Optimised cluster/hub storage operations can be used to provide short-term or peak services independently from specific geological characteristics.

[67] Based on current use for natural gas.

[68] The Fuel Cells and Hydrogen Joint Undertaking (FCH JU) has issued a Call for Proposal for Cyclic testing of renewable hydrogen storage in a small salt cavern (deadline was 29 April 2021). The project should demonstrate the feasibility of fast cycling in salt caverns, a least one cycle a day. The aim is to reach CAPEX of €450/kg of hydrogen stored or an additional cost to hydrogen released of €1/kg. European Commission, "Cyclic testing of renewable hydrogen storage in a small salt cavern," 2020.

[69] Range of total hydrogen WGC per facility. Most larger facilities consist of multiple caverns; individual cavern WGC varies less.

Storage type	Depleted field	Aquifer	Salt cavern	Lined rock cavern
Largest expenses (new development)	Well infrastructure, cushion gas, compression	Exploration and determination of geology, well infrastructure, cushion gas, compression	Formation of the cavern, disposal of brine, cushion gas, compression	Blasting of the cavern, steel lining, cushion gas, compression
Geographic availability	Most of Europe	Most of Europe	Primarily northwest Europe; 9 EU member states, the UK, Norway, Bosnia & Herzegovina, and Albania[70]	Anywhere with igneous or metamorphic rock
General technical readiness level for hydrogen storage	3-6[71]	3	8	5-6
Suitability for hydrogen	Hydrogen-methane blending (up to 10% hydrogen) proven; pure hydrogen storage under study	Under study, but learnings from depleted fields can be utilised	Proven	First hydrogen storage in development (2022)
Suitability factors	Operational conditions, fluid and rock composition, bacteriological activity	Operational conditions, fluid and rock composition, bacteriological activity; tightness (for new storage development only)	Salt domes are superior to bedded salt structures	Metamorphic or igneous rock; low steel price
R&D needed	Effects of residual natural gas, in-situ bacteria reactions	In-situ bacteria reactions, tightness of rocks	Accuracy of the timing of injections and withdrawals	Compatibility of lining materials with hydrogen

A.1 Salt caverns

Salt caverns are artificial structures constructed in underground rock salt formations. Depths of salt caverns in Europe range from 300 m to 1,800 m. Pressures can range from 35 bar to 210 bar, but typical operating pressures are around 80-120 bar.

To construct salt caverns, water is injected underground, dissolving the rock salt. The resulting brine is extracted and disposed of, leaving an underground cavity that is completely enclosed in salt. Surface and subsurface infrastructure must also be purchased and installed. Salt caverns can be created in either salt domes or bedded salt formations. Salt domes are thicker and homogenous, consisting of pure salt.

[70] Dilara Caglayan et al., "Technical potential of salt caverns for hydrogen storage in Europe," *International Journal of Hydrogen Energy*, Volume 45, February 2020.

[71] Some operators have tested hydrogen and natural gas blends, and rocks from reservoirs have been tested with pure hydrogen in laboratory settings.

Bedded formations are shallow and wide and consist of layers of salt and other minerals. Salt caverns in salt domes are typically higher capacity and lower cost than those in bedded formations.[72]

Transport and disposal of brine is the most difficult step in salt cavern development. Due to environmental concerns, it might be difficult to release the brine into the ocean, so in some cases, another location must be found. There may be opportunities to partner with salt producers to create a cavern for gas storage and provide the brine to the salt producer. Salt caverns typically take 3-7 years to develop (permitting might take up a significant part of that timeline, similar to other types of underground storage).

Salt caverns have only one well per cavern that all injecting and extracting is done through.[73] They also require less cushion gas than depleted natural gas reservoirs or aquifers, typically about 30% of capacity. Salt caverns have sufficient injection and withdrawal rates to perform up to 10 injection and withdrawal cycles per year but are often lower in capacity than natural gas reservoirs, making them ideal for peaking storage facilities.[74] Some salt cavern facilities are used for seasonal storage as well; these typically consist of many caverns. Their injection and withdrawal rates are theoretically limited only by the throughput of the well infrastructure and the technical design of surface installations. It is common for salt cavern storage facilities to have multiple caverns at one site (sometimes tens of caverns) because there is a limit to the size of a single cavern before it becomes unstable. The total working gas volume can also be increased by developing multiple caverns.

Hydrogen storage in salt caverns

Hydrogen has been successfully stored in salt caverns at three different locations. Teesside in the UK is the only such site in Europe, consisting of three salt caverns with a total capacity of 1,000,000 m^3. The site has been operational for nearly 50 years, and the hydrogen is used for ammonia and methanol production. In Texas in the US, hydrogen is stored in two separate salt caverns, both for use in the petrochemical industry. This makes them the only proven underground hydrogen storage technology so far, though other technologies are under study and experience so far indicates they are likely suitable as well.[75] Many ongoing and planned pilots are aimed at demonstrating hydrogen storage in salt caverns across Europe.[76] These include HyCAVmobil by EWE;[77] HyPSTER by Storengy;[78] HyGeo by Teréga;[79] H_2@Epe by Uniper; Green Hydrogen Hub by Gas Storage Denmark;[80] HYPOS by VNG;[81] and HyStock by Gasunie.[82]

The advantage of these formations is that rock salt is inert to hydrogen and sufficiently impermeable, so the hydrogen losses from diffusion through the rock are negligible. The most likely method of escape, if any, is through the wells. Salt domes are straightforwardly suitable for hydrogen storage from a geological perspective. Bedded salt formations contain layers of minerals throughout the salt. They, therefore, need to be investigated more thoroughly than salt domes to determine the maximum acceptable operating pressure of the weakest lithology and to confirm that none of the mineral layers will react with hydrogen to produce impurities.

[72] A.S. Lord et al., "Geologic storage of hydrogen: Scaling up to meet city transport demands," *International Journal of Hydrogen*, Volume 39, September 2014.

[73] Radoslaw Tarkowski, "Underground hydrogen storage: Characteristics and prospects," *Renewable and Sustainable Energy Reviews*, Volume 105, May 2019.

[74] The FCH JU and some storage operators are investigating much faster cycling of salt caverns for hydrogen.

[75] Radoslaw Tarkowski, "Underground hydrogen storage: Characteristics and prospects," *Renewable and Sustainable Energy Reviews*, Volume 105, May 2019.

[76] The following list is not exhaustive.

[77] EWE, "Storing hydrogen – HyCAVmobil research project," 2020.

[78] Storengy, "HyPSTER, 1st demonstrator for H_2 green storage," 25 January 2021.

[79] Teréga, "HDF and Terega join forces in the geological storage of green hydrogen and launch the HyGeo project," 7 July 2020.

[80] Gas Storage Denmark, "New, large-scale hydrogen hub to support Denmark's green transition," 1 December 2020.

[81] VNG, "H_2 Research Cavern," 2020.

[82] Gasunie, "Hystock," 2021.

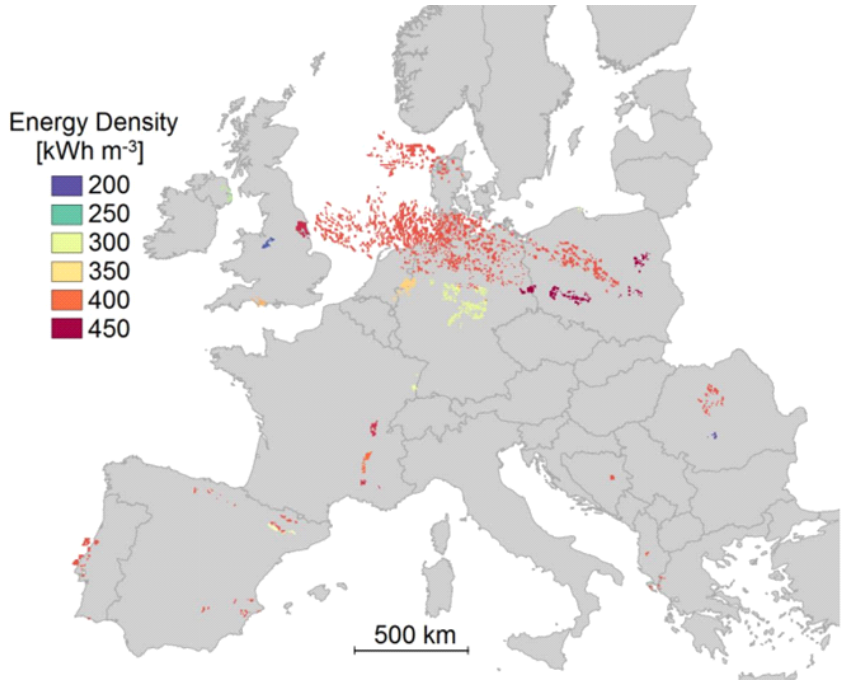
Because of their ability to rapidly switch between injection and withdrawal and to complete many injection and withdrawal cycles within a year, salt caverns can play a key role in peak shaving and hourly storage needs. Seeing as hydrogen supply and demand balancing needs at hourly, daily, and weekly timescales are projected to be significant, salt caverns will likely be useful to the hydrogen system.

To convert a salt cavern that previously stored natural gas for hydrogen, brine can be injected into the cavern to purge the natural gas cushion gas. Once it is full of brine, the equipment can be replaced and retrofitted as needed to ready the cavern for hydrogen storage. The brine is then withdrawn and replaced with hydrogen. Testing must be performed to determine whether any significant residual methane remains in the cavern walls. Repurposing a natural gas salt cavern for hydrogen storage is estimated to take a similar length of time as required to create a new salt cavern.

Hydrogen does not react with salt, so there is no risk of generating impurities in salt cavern storage. There may be a small amount of water in hydrogen withdrawn from salt caverns as they often contain remaining brine at the bottom. Gas drying infrastructure is common among natural gas storage, so water removal is not a major concern.

While salt caverns are a promising storage type for hydrogen due to their decades of success and flexibility that is desirable for a hydrogen network, their availability is limited geographically. Figure 10 shows the location and energy density of salt deposits across Europe.

Figure 10 – Distribution of potential salt cavern sites across Europe with their corresponding energy densities (cavern storage potential divided by the volume)[83]



[83] Caglayan et al., "Technical potential of salt caverns for hydrogen storage in Europe," International Journal of Hydrogen Energy, Volume 45, February 2020.

Only a limited number of EU member states have the technical potential for salt cavern storage, and many of the potential locations are located offshore, mainly in the North Sea. Salt caverns (for natural gas storage) have been developed in six EU countries (Denmark, France, Germany, the Netherlands, Poland, and Portugal) and the UK, with a total estimated working gas capacity of 50 TWh of hydrogen.[84] Beyond that, the technical potential estimate shows that salt caverns could be developed additionally in Greece, Romania, and Spain. The total technical potential of salt caverns in Europe is estimated at approximately 85,000 TWh of hydrogen (~23,000 TWh of hydrogen onshore).[85] This far exceeds the expected need for hydrogen storage in Europe. However, it would still require a tremendous number of salt cavern sites to be developed. In addition, the geographical ability of the locations brings difficulties to balancing the hydrogen infrastructure networks with salt cavern storage alone because many countries do not have the geological structures necessary to develop them. While the theoretical potential storage in salt caverns is large, there are considerable barriers to development and major practical limitations to relying on salt caverns alone.

A.2 Depleted gas reservoirs

Depleted gas reservoirs are underground geological structures that naturally contained hydrocarbons underground for millions of years. After the reservoirs are depleted, they can be used to store natural gas. Operating pressures and depths vary considerably depending on the structure, with pressures in the range of 15 bar to 285 bar and depths of 300 m-2,700 m. It typically takes 3-10 years to develop a depleted gas field into storage depending on the characteristics of the field and the extent of the tests required to determine its suitability. Depleted natural gas reservoirs have been used for storage for decades and make up about 64% of the total natural gas storage capacity in the EU27 and the UK.

Depleted natural gas reservoirs consist of porous, permeable sedimentary rocks located underneath an impermeable cap rock and sealed on all sides by impermeable rocks. They have multiple wells located throughout the gas reservoir, sometimes remaining from when it was operational for gas production and sometimes drilled strategically to improve the operation of the storage. Unlike salt caverns, the injection and withdrawal rates of porous rock structures are limited by the permeability of the rock.

Reservoirs can contain and store large amounts of gas, often several weeks' worth of demand, and typically complete one cycle of injection and release per year because it takes months to inject and withdraw the total working gas volume. They are used most commonly for large volume seasonal natural gas storage, though there are examples of them being used also for more short-term flexibility. Depleted gas fields are typically operated with about 50%-60% of their total gas capacity in cushion gas; this varies depending on the structure and desired injection and withdrawal rates.[86]

[84] Guidehouse estimate based on data from GIE.

[85] This estimate includes also the UK, Norway, Bosnia & Herzegovina, and Albania. From Caglayan et al., "Technical potential of salt caverns for hydrogen storage in Europe," *International Journal of Hydrogen Energy, Volume 45, February 2020.*

[86] A.S. Lord et al., Geologic storage of hydrogen: Scaling up to meet city transport demands," *International Journal of Hydrogen*, Volume 39, September 2014.

Depleted gas fields can switch between injection and withdrawal within 1-2 hours in most cases, so they can be operated flexibly. Such fast switching is not done regularly. Rather, netting is a common practice to reduce the need to change between the operating cycles. Some storage operators also use optimised cluster/hub operation of storage sites to create a similar effect.

They can also be designed to operate as peaking facilities with larger injection and withdrawal rates and multiple cycles per year by operating with large cushion gas volumes, a higher number of wells, or additional compressor stations. This comes at additional investment and operational costs.

Hydrogen storage in depleted gas fields

Pure hydrogen has not yet been stored in depleted gas fields. However, operators interviewed for this study expressed confidence in their technical ability to do so based on studies performed so far, provided the mineralogy is acceptable for hydrogen.

In principle, natural gas reservoirs should be able to operate as hydrogen storage as well because they have demonstrated their ability to store gas for millions of years. Several storage operators are in various stages of examining this. The Underground Sun Storage,[87] a pilot conducted by RAG Austria from 2014 to 2021, tested storage of a blend of 10% hydrogen and 90% methane in a depleted gas field and had no issues with containment STOGIT, OMV, and Enagás are planning to examine a broad range of hydrogen and methane admixtures, up to storing pure hydrogen within a series of field tests. In the 1950s, town gas derived from coal, which consisted of up to 50% hydrogen, was stored in some depleted gas fields in Europe.

For hydrogen storage in depleted gas fields, one consideration is hydrogen's higher compressibility factor, diffusivity, and lower viscosity, meaning it may be more difficult to contain than natural gas. Computer simulations have shown that hydrogen diffusion through the cap rock is negligible, and the most likely method of escape, if any, would be through the wells, as is the case with all types of underground gas storage.[88] Containing hydrogen in depleted gas fields does not appear to be an issue, but this should be confirmed experimentally on a case-by-case basis when repurposing a depleted gas field for hydrogen storage.

Another important characteristic of hydrogen that differs from natural gas is its reactivity. In the presence of sulphate-reducing bacteria, hydrogen reacts with sulphate-containing minerals to produce hydrogen sulphide, a contaminant for combustion and fuel cell purposes. It also reacts with CO_2 and carbonate-containing minerals in the presence of methanogenic bacteria to produce methane.[89] Reservoirs must be evaluated on a case-by-case basis to determine the extent to which these reactions occur and whether it is manageable. Gas treatment to deal with the impurities mentioned is a standard part of storage operation, so impurities are only an issue in so far as they add to the operating cost. According to storage operators, the mineralogy of depleted gas fields is relatively consistent across Europe and those tested have proven suitable from a mineralogy perspective so far.

[87] See RAG, "Underground Sun Storage," 2021.

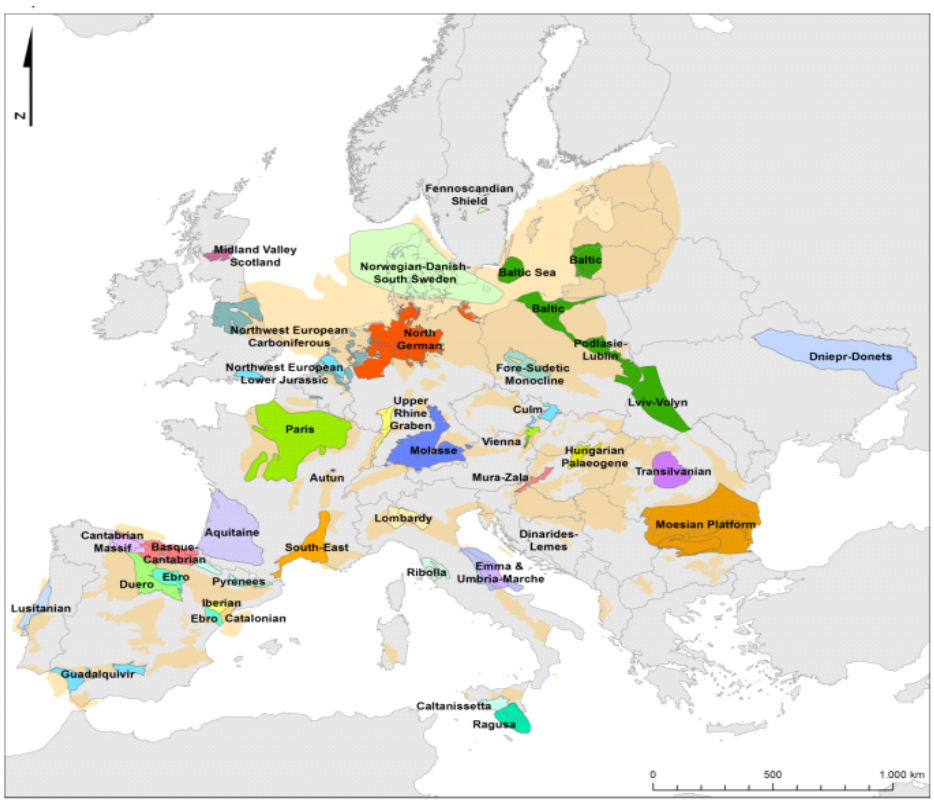
[88] A. Amid et al., "Seasonal storage of hydrogen in a depleted natural gas reservoir," *International Journal of Hydrogen Energy*, Volume 41, March 2016.

[89] C. Hemme and W. van Berk, "Hydrogeochemical Modeling to Identify Potential Risks of Underground Hydrogen Storage in Depleted Gas Fields," November 2018.

Depleted gas field operators interviewed for this study indicated they are investigating storing a blend of natural gas and hydrogen in the short and medium term. Blends of natural gas and hydrogen are less likely than pure hydrogen to react with minerals, and the existing infrastructure can handle blends of natural gas and hydrogen. The amount of hydrogen that can be added before infrastructure needs to be replaced still needs to be determined and likely on a case-by-case basis. It may be possible to store methane-hydrogen blends and separate them into pure methane and pure hydrogen after withdrawal. More investigation is required to determine what infrastructure would be required and if this can be done economically. However, if possible, this could be a useful solution in the short term when hydrogen demand is too low to justify pure hydrogen storage in an entire gas field. The first operational pure hydrogen storage in a depleted gas field is expected in 2030, operated by RAG Austria.

Advantages to depleted gas fields as hydrogen storage are that they are larger in volume than salt caverns, and their geology is already well understood from being operated for natural gas. Compared to the development of new salt caverns, they already have a well infrastructure for natural gas, some of which can be potentially retrofitted or repurposed for hydrogen.[90] Gas fields are also more widespread than salt caverns. Figure 11 shows the oil and gas basins across Europe, many of which contain depleted gas fields suitable for storage.

Figure 11 – Map of oil and gas basins in Europe[91]



[90] A.S. Lord et al., Geologic storage of hydrogen: Scaling up to meet city transport demands," *International Journal of Hydrogen*, Volume 39, September 2014.

[91] EUOGA is an effort to collect data on shale basins across Europe. Britze, *European Unconventional Oil and Gas Assessment*, 2017.

A.3 Aquifers

Aquifers are similar structures to natural gas reservoirs in that they are porous sedimentary rock structures; however, they contain water instead of natural gas. As with depleted gas fields, the average cushion gas volume is approximately 50% of the total gas volume. This varies depending on the geological structure, placement of wells, and operational needs. Operational pressures of aquifers in Europe range from 30 bar to 315 bar, and depths range from 400 m to 2,300 m. Aquifers typically take a similar length of time to develop as depleted fields, plus added time for geological studies when creating new storage in an aquifer. Aquifers are common for natural gas storage, representing about 13% of existing capacity in Europe.

Unlike depleted gas fields, which are known to be tight because they were originally filled with gas, aquifers may not be tight on all sides; extensive geological surveys are required to determine whether or not there are ways for the gas to escape before they can be converted into storage. These surveys typically take about 2 years to complete. Aquifers are developed for storage by injecting them with methane, displacing the water in its pores down and to the side. Depending on the structure of the aquifer and the positioning of the well, the displaced water can sometimes be used in place of cushion gas, refilling the pores as the methane is depleted. This is called an active water drive.[92] The extent to which this method can be used depends on the rate at which water diffuses into the pores as gas is withdrawn. Using cushion gas instead is often more desirable. As in depleted gas fields, aquifers have multiple wells, strategically placed to optimise storage performance. Depending on well placement, aquifers may have pockets of gas separated from one another by water. In these cases, different gases could be stored under different wells without mixing.

Hydrogen storage in aquifers

Hydrogen storage in aquifers has not yet been tested on the ground. However, the Lacq Hydrogen Project plans to use one of Teréga's aquifers for hydrogen storage.[93] The project should be operational by 2026. Enagás is also investigating the feasibility of storing hydrogen in its aquifers. Given that depleted fields and aquifers are both porous rock structures, successful demonstration of hydrogen storage in depleted fields suggests it is possible in aquifers as well. As in depleted gas fields, sulphate and carbonate-containing minerals can result in the production of contaminants, so this must be studied and accounted for during hydrogen storage development. Water is a common impurity in gas stored in aquifers, so gas drying infrastructure is an important component of the gas treatment process.

Repurposing aquifers being used to store natural gas for hydrogen storage is similar to depleted gas fields due to the similarities in structure. In some cases with active water drives, the water may be used to gradually purge some of the methane cushion gas. In most cases this process is likely to be too slow to be economically efficient. Methane will have to be gradually removed from the aquifer over years in small amounts admixed with the hydrogen withdrawn from the aquifer.

[92] Active water drives can also be present in depleted gas fields.

[93] FuelCellWorks, Enagas: Franco-Spanish Lacq Hydrogen Project Gets Underway, 2021.

As for the development of new capacities, the geologies of aquifers not yet used for storage are less well-known than those of depleted gas fields. Geological studies are required to determine the tightness of the cap rock and surrounding rock and which minerals are present. Undeveloped aquifers do not have an existing well infrastructure, so all surface and subsurface infrastructure would have to be purchased and installed.[94] Depending on the structure, an active water drive may be used to avoid cushion gas because hydrogen has low solubility in water.[95] The well infrastructure, geological studies, and in some cases, cushion gas are additional CAPEX that make aquifers more costly to develop than depleted gas fields. However, because the cavern itself does not need to be constructed, they are still often cheaper to develop than salt caverns or lined rock caverns.[96] Porous aquifers are quite widespread and are available in most European countries. However, it is uncertain what portion of the aquifers are suitable for hydrogen storage and where those are located.

Figure 12 shows the locations of all aquifers in Europe. The regions shaded in blue represent porous aquifers. Porous aquifers with the right porosity and permeability sufficiently enclosed on all sides can be used to store gas.

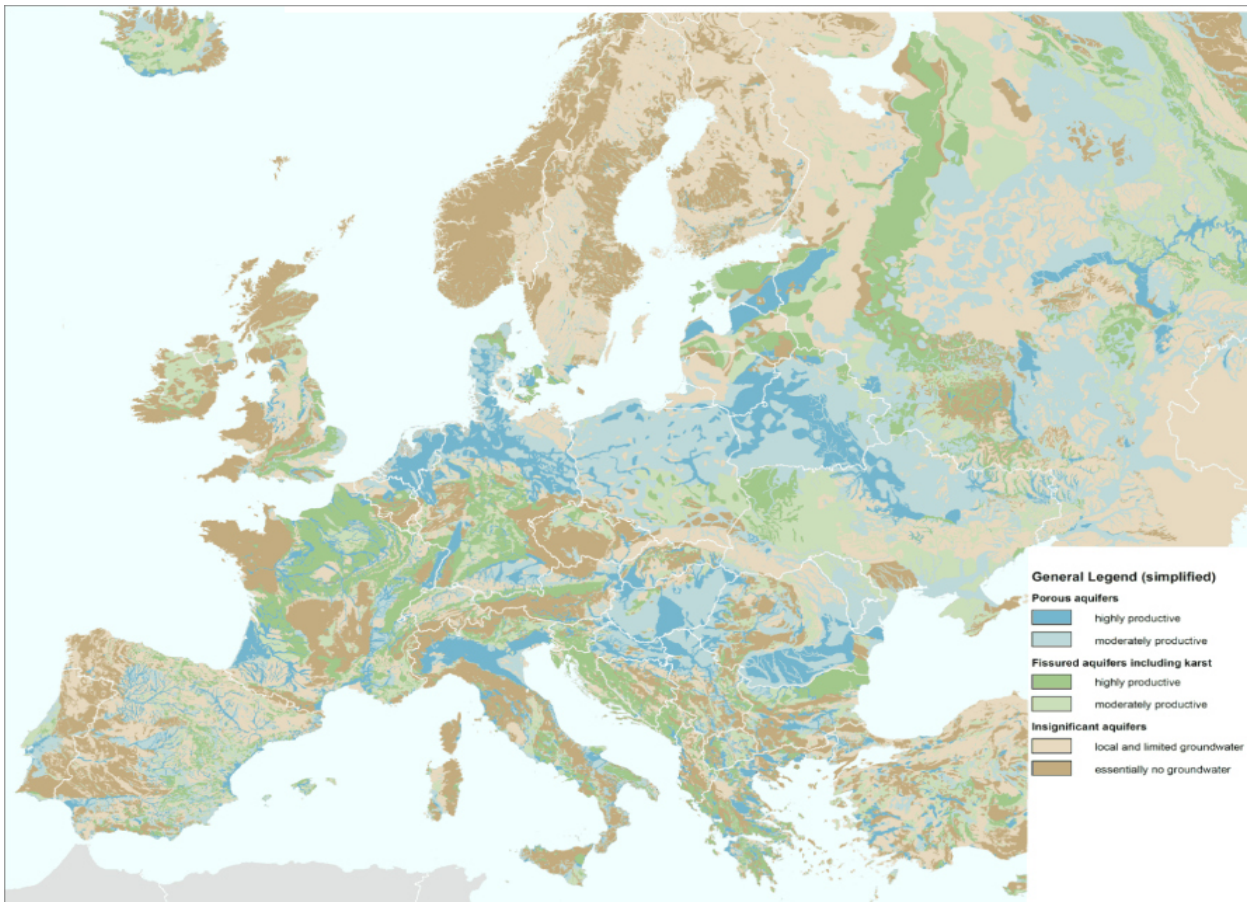
[94] A.S. Lord et al., Geologic storage of hydrogen: Scaling up to meet city transport demands," *International Journal of Hydrogen*, Volume 39, September 2014.

[95] Radoslaw Tarkowski, "Underground hydrogen storage: Characteristics and prospects," *Renewable and Sustainable Energy Reviews*, Volume 105, May 2019.

[96] A.S. Lord et al., Geologic storage of hydrogen: Scaling up to meet city transport demands," *International Journal of Hydrogen*, Volume 39, September 2014.

[97] EGDI, "Hydrogeological Map of Europe," 2021.

Figure 12 – Map of aquifers in Europe[97]



A.4 Hard Rock Caverns

Hard rock caverns are the newest of the four main underground storage technologies, with only one facility in operation for natural gas storage in Sweden. Hard rock caverns, like salt caverns, are artificial structures consisting of caverns created in metamorphic or igneous rock. The caverns are lined with a layer of concrete to create smooth walls, which are then lined with steel or plastic. Because they are carefully crafted and lined, hard rock caverns have no risks of impurities and can be operated at higher pressures than the other structures. They can also experience several injection and withdrawal cycles per year, making them well-suited for peaking purposes. They also require relatively little cushion gas.

Hydrogen storage in hard rock caverns

Hydrogen has not yet been stored in a hard rock cavern; however, a lined rock cavern is being developed by SSAB, LKAB, and Vattenfall as part of the HYBRIT green steel project. The rock cavern is expected to become operational in 2022.[98] Hard rock caverns will likely be suitable for hydrogen, but they will likely be reserved for peaking facilities in geographies with no other storage options because they are costly to develop. One potential concern with steel-lined caverns is that long-term exposure of steel to hydrogen can cause hydrogen embrittlement. This implies that a higher grade of steel or another kind of liner may need to be used.[99]

A.5 Surface and sub-surface infrastructure

All underground gas storage has surface and subsurface infrastructure used to connect the storage to the grid. Some of this includes wells, piping, compressors, and purification infrastructure. For hydrogen repurposing, the kinds of equipment required are more or less the same.

Studies are ongoing to determine the necessary changes to infrastructure and associated costs. First estimations assume that retrofitting existing storage sites to pure hydrogen storage will cost around 20%-30% of the cost to construct a new storage site.

Hydrogen and methane have different physical properties and likely different purity requirements; thus, parts of the existing infrastructure will have to be modified or replaced, including compressors. Hydrogen can cause embrittlement of steel over prolonged contact, so all materials need to be tested for compatibility. Lower grades of steel may need to be coated or replaced.

Different types of storage have different possible impurities, so the gas treatment infrastructure varies. It has not yet been determined how much of the existing gas purification infrastructure from natural gas storage can be used for hydrogen or how much it will cost to replace what needs replacing.

[98] SVT, "The explosions for the hydrogen storage in Lulea will begin shortly," 2021.

[99] A.S. Lord et al., Geologic storage of hydrogen: Scaling up to meet city transport demands," International Journal of Hydrogen, Volume 39, September 2014.

A.6 Cost of different storage types

The major cost components for developing underground storage are cushion gas, site exploration and development, compressors, and other surface and subsurface infrastructure. It is difficult to generalise storage costs because of the wide variety in sizes, operating conditions of storage, and the number of injection and withdrawal cycles. Table 5 summarises the findings. These estimates are based on literature with a set of assumptions about the storage specifics and the way the storage would be operated (e.g. the number of cycles), which all influence the calculated levelised cost of storage (LCOS). As such, the summary should not be seen as a comparison between different types of storage (that is too premature), but rather an indication of the order of magnitude of the investment and levelised cost.

[100] [1] A.S. Lord et al., Geologic storage of hydrogen: Scaling up to meet city transport demands," *International Journal of Hydrogen*, Volume 39, September 2014.
[2] R. K. Ahluwalia et al., "System level analysis of hydrogen storage options," 2019.
[3] Bloomberg, *Hydrogen Economy Outlook*, 2020.
[4] DNV GL, *Hydrogen in the electricity value chain*, 2019.
[5] M. Reuß et al., "Seasonal storage and alternative carriers: A flexible hydrogen supply chain model," *Applied Energy*, Volume 200, 15 August 2017.

Table 5 – LCOS and investment cost (CAPEX) estimations for hydrogen underground storage[100]

Type of storage	LCOS (€/kgH_2)	CAPEX (€/kgH_2)	Notes
Salt cavern	0.18	29.00	80,000 m^3 [2]
	0.23	N/A	[3]
	0.35	25.50	WGC 35,261 tH_2 [4]
	1.34	27.46	[1]
	N/A	€81 million	500,000 m^3 [5]
Depletes gas field	1.02	17.41	WGC 1,912 tH_2 [1]
Aquifer	1.07	17.80	WGC 1,912 tH_2 [1]
Hard rock cavern	2.30	38.91	WGC 1,912 tH_2 [1]

Appendix B.
Natural gas statistics

Table 6 – Natural gas consumption and storage statistics by country[101]

Country	Average annual consumption (TWh/year) (2014–2019)	Average day demand (TWh/year) (2014–2019)	Day peak demand (TWh/day) (2019)	2-week peak demand (TWh/2 weeks) (2019)	Storage WGC (TWh)	Storage withdrawal rate (TWh/day)
Austria	92	0.25	0.45	6.24	95	1.06
Belgium	180	0.49	1.05	12.85	9	0.17
Czech Republic	89	0.24	0.44	6.15	43	0.81
Denmark	36	0.10	0.13	1.83	10	0.18
Estonia	5	0.01	0.03	0.41	0	0
Finland	28	0.08	0.13	1.79	0	0
France	470	1.29	5.28	63.52	132	2.59
Germany	929	2.54	4.42	61.91	255	7.34
Greece	46	0.13	0.30	3.71	0	0.04
Hungary	103	0.28	0.64	8.09	70	0.84
Ireland	53	0.15	0.18	2.54	0	0
Italy	745	2.04	4.05	50.50	195	3.18
Luxembourg	9	0.03	0.05	0.59	0	0.00
Netherlands	388	1.06	2.01	24.96	144	2.95
Poland	193	0.53	0.86	10.96	38	0.88
Slovakia	49	0.13	0.22	3.07	50	0.61
Slovenia	9	0.02	0.05	0.61	0	0
Spain	339	0.93	1.18	13.82	34	0.20
Sweden	12	0.03	0.04	0.61	0.09	0.01
UK	850	2.33	4.20	52.04	20	2.34
Total	**4,624**	**12.66**	**25.70**	**326.20**	**1,096**	**23.20**

[101] Total and average natural gas consumption comes from Eurostat (Eurostat, "Supply, transformation and consumption of gas - monthly data," 2021). Peak demand comes from ENTSOG (ENTSOG, "Transparency Platform," 2021). Storage data comes from GIE.

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Gas Infrastructure Europe (GIE) is the association representing the interests of European gas infrastructure operators. GIE members are active in transmission, storage and regasification via LNG terminals of renewable and low-carbon gases, including natural gas and hydrogen. Gathering around 70 industry entities from 27 European countries, GIE perfectly embodies the multiple transitional decarbonisation pathways of the EU regions. The association's vision is that by 2050, the gas infrastructure will be the backbone of the new innovative energy system, allowing European citizens and industries to benefit from a secure, efficient and sustainable energy supply.

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