HyUSPRe

Hydrogen **U**nderground **S**torage in **P**orous **Re**servoirs

Hydrogen storage potential of existing European gas storage sites in depleted gas fields and aquifers

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Executive Summary

This report on hydrogen storage in porous reservoirs covers the state of knowledge for European resources assuming the conversion of existing underground gas storage sites. The report establishes the location and capacity of these existing resources and summarises the outcomes as a long list and map of potential hydrogen storage sites in depleted gas fields and aquifers. The advantages of the existing inventory are the known attributes and networked status. Current additions to the existing reserve – pilots, prospects, exploration targets – are relatively small, at most a few percent of the total inventory, and will be addressed in more detail in a further report. The reported natural gas and hydrogen capacities are expressed in terawatt-hours. 1 TWh is equivalent to 0.11 bcm of natural gas and 0.35 bcm of hydrogen[1].

The main outcome of our research is that the potential for hydrogen storage in porous reservoirs consists primarily of depleted gas fields, and to a much lesser degree, aquifers – see Fig 1. The known reserve of operational and planned natural gas storage sites - 86% depleted gas fields and 14% aquifers – if converted, provides 750 TWh of hydrogen storage. This is sufficient for a mid-range scenario of 2,500 TWh of annual hydrogen demand in 2050, supported by 30% storage. Factoring in a salt cavern contribution of 170 TWh, not addressed in this study, the total capacity through conversion of existing and planned sites is 920 TWh.

The natural gas storage inventory for porous reservoirs is a bankable resource of 108 operated sites, of which 84 are depleted gas fields with another 31 in planning. Just 24 of the operated sites are aquifers, 11 of which are in France, with no further aquifer stores planned for Europe. We infer that this partially reflects the expense of installing cushion gas.

We have noted and avoided the common approach of extremely large theoretical capacity estimates which result from including all potential prospects. Such a low threshold to screening leads to petawatt-hour capacities that exceed even high demand forecasts by orders of magnitude but fails to identify a long list of likely candidate sites and locations that conform to the existing network and expected requirement of a European hydrogen economy. The existing network will likely persist as a backbone, and current demand distributions are well established and indicative of the location and capacity of sites for the hydrogen network.

Net zero 2050 demand forecasts for hydrogen vary widely, but 2500 TWh appears to be a reasonable mid-range scenario supported by multiple studies. 750 TWh would provide 30% storage for the annual demand, which is comparable with the current natural gas storage provision. Reasonable high-and-low demand scenarios could conceivably increase or decrease the storage contribution to 1000 TWh or 250 TWh.

To match a high-demand scenario with additional depleted gas fields alone, the potential hydrogen capacity of the existing operational resource, 560 TWh, would need to be approximately doubled. It is reasonable to assume that this added capacity will be found close to existing sites. Such sites have proven difficult to identify given the commercial sensitivity of potential acquisitions and, in some cases, the large number of candidate sites available. However, given the dominance of depleted gas field storage, it is reasonable to assume that inventory doubling could be achieved in most cases by operators either acquiring a depleted gas field close to their existing site or by increasing the capacity of the existing site. Indeed, this is reflected in the inventory of 31 planned sites of which 27 are listed as extensions.

[1]*Hydrogen 0.0846 kg/m^3, 33.3 kWh/kg; Natural Gas 0.712 kg/m^3,13.1 kWh/kg – LHV & STP (ISO 13443) Source: www.unitrove.com/engineering/tools/gas*

The storage available through the conversion of existing operational sites, including aquifers, 660 TWh, is a good match to a mid-range demand scenario of 500 TWh. The 750 TWh estimate includes planned sites and assumes no closures and no cancellations. The estimate also assumes that natural gas storage will be entirely displaced by hydrogen in the coming decades as town gas was in the 1970s and 1980s. The degree of displacement by 2050 is highly uncertain and beyond the scope of this report which focuses on the potential resource capacity and location of existing storage assets.

Finally, the estimate also reflects the conversion heuristic applied, a rate-limited capacity for 90 days of withdrawal (WGC-90), which differs by a factor of 2 from the more common energy-density capacity estimate for working gas capacity (WGC-ED). The difference between these approaches has been outlined in detail in the report methodology.

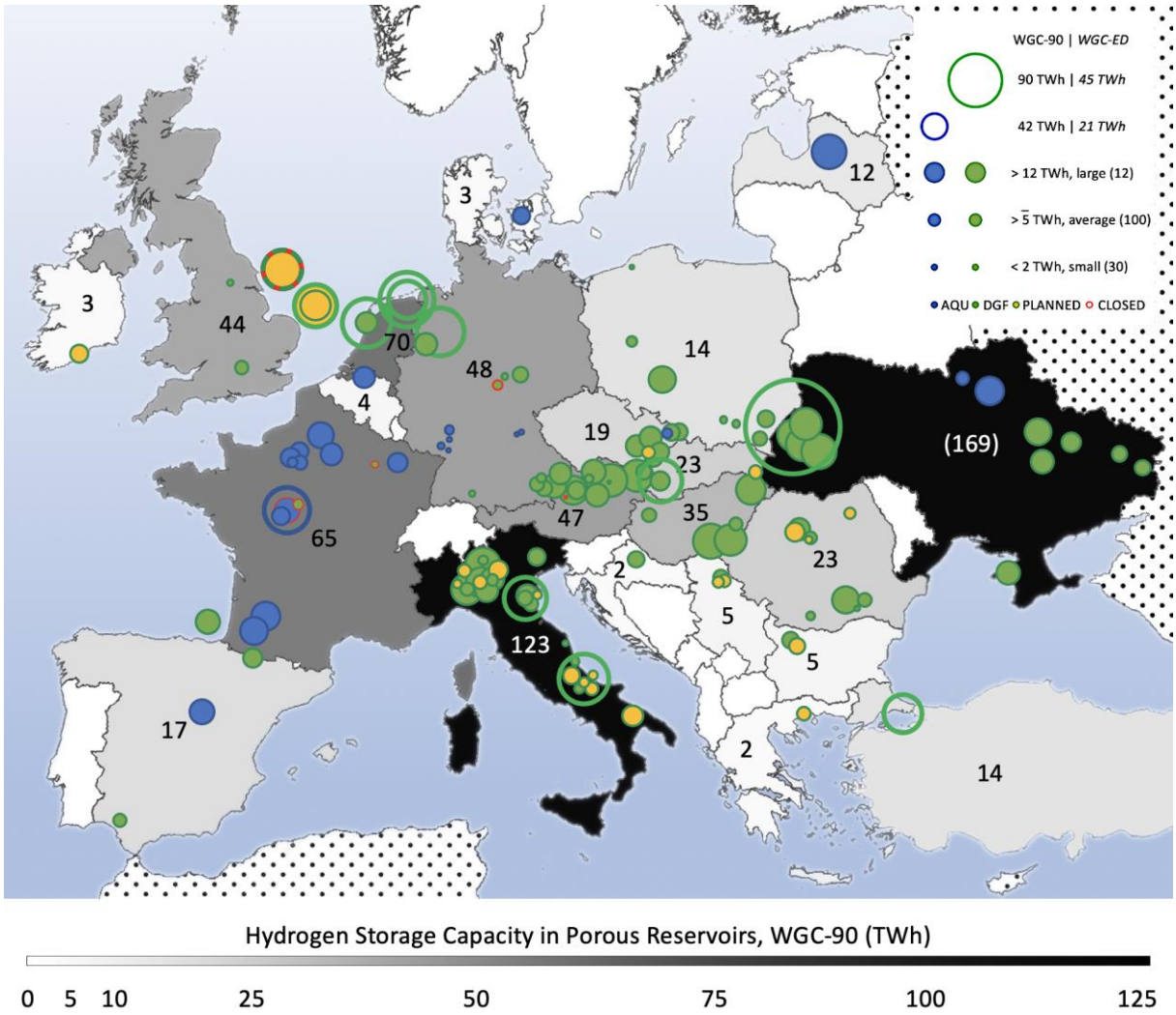

Figure 1a. Hydrogen storage capacity, TWh, for Europe in porous reservoirs currently used for storing natural gas. ***The total capacity for currently operated sites, assuming conversion, is 664 TWh. The capacity including planned sites is 747 TWh. Values centred in countries represent the total potential hydrogen capacity*** *identified for that country, as documented in this study's long list. Ukraine's exceptionally high value appears in brackets as it exceeds the grey scale maximum of 125 TWh. 86% of the inventory consists of depleted gas fields that are currently natural gas storage sites (green circles). 14% are aquifer sites (blue circles); 11% of the inventory represents planned sites, all depleted gas fields (yellow circles). 1% of the inventory consists of additions not in the GIE database. Very large sites are represented by hollow rings (N=12), all other sites are solid circles. Closed sites are ringed in red. The key indicates that the displayed values and circles represent conversion estimates based on the WGC-90 heuristic. The common energy density heuristic, WGC-ED, is exactly half the WGC-90 value.*

Hydrogen capacity	TWh
Ukraine	169
Hungary	35
Romania	23
Poland	14
Latvia	12
Bulgaria	5
Serbia	5
Italy	123
France	65
Spain	17
Turkey	14
Greece	2
Netherlands	70
Germany	48
United Kingdom	44
Belgium	4
Denmark	3
Ireland	3
Austria	47
Slovakia	23
Czech Republic	19
Croatia	3

Figure 1b. European hydrogen storage capacity in porous reservoirs for existing gas storage by region and country. ***The total capacity for currently operated sites, assuming conversion, is 664 TWh. The capacity including planned sites is 747 TWh. Half of the capacity is located in Ukraine, Italy, and the Netherlands, 362 TWh.*** *The sunburst chart illustrates that without the substantial contribution of storage from the Ukraine – much of which, 90 TWh (WGC-90), is from a single site in western Ukraine – Italy, Netherlands, France, Germany, and Austria are the largest storage contributors to potential hydrogen capacity in porous reservoirs. The substantial UK potential is almost entirely planned capacity without a final investment decision. France is notable for its contribution being largely aquifers, in direct contrast to the rest of the portfolio, which is dominated by depleted gas fields.*

About HyUSPRe

Hydrogen **U**nderground **S**torage in **P**orous **Re**servoirs

The HyUSPRe project researches the feasibility and potential of implementing large-scale underground geological storage for renewable hydrogen in Europe. This includes the identification of suitable porous reservoirs for hydrogen storage, and technical and economic assessments of the feasibility of implementing large-scale storage in these reservoirs to support the European energy transition to net zero emissions by 2050. The project will address specific technical issues and risks regarding storage in porous reservoirs and conduct an economic analysis to facilitate the decision-making process regarding the development of a portfolio of potential field pilots. A techno-economic assessment, accompanied by environmental, social, and regulatory perspectives on implementation will allow for the development of a roadmap for widespread hydrogen storage by 2050, indicating the role of large-scale hydrogen storage in achieving a zero-emissions energy system in the EU by 2050.

This project has two specific objectives. Objective 1 concerns the assessment of the technical feasibility, associated risks, and the potential of large-scale underground hydrogen storage in porous reservoirs for Europe. HyUSPRe will establish the important geochemical, microbiological, flow, and transport processes in porous reservoirs in the presence of hydrogen via a combination of laboratory-scale experiments and integrated modelling; and establish more accurate cost estimates to identify the potential business case for hydrogen storage in porous reservoirs. Suitable storage sites will be identified, and their hydrogen storage potential will be assessed. Objective 2 concerns the development of a roadmap for the deployment of geological hydrogen storage up to 2050. The proximity of storage sites to large renewable energy infrastructure and the amount of renewable energy that can be buffered versus time varying demands will be evaluated. This will form a basis for developing future scenario roadmaps and preparing for demonstrations.

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Table of Content

Glossary

HyUSPRe	Hydrogen Underground Storage in Porous Reservoirs
bcm	Volume, billion cubic meters at standard conditions, STP
Specific Gravity	The ratio of a material's density with that of water at 4 °C
LHV	Lower heating value
STP	Standard temp and pressure, 15 ºC & 101.325 kPa, ISO 13443
Long List	HyUSPRe list of all storage sites with hydrogen storage potential
Short List	HyUSPRe curated list for potential sites of high interest
Reserve	Proven and operational capacity after SPE PRMS and SRMS
Contingent	Identified resource that has matured but has not reached FID
FID	Final investment decision, approx. 5 years before commissioning
Resource	Theoretical and contingent capacity including planned sites
SPE	Society of Petroleum Engineers
PRMS	Petroleum Resource Management System
SRMS	Storage Resource Management System
Static Capacity	Storage capacity, based on static properties – volume, energy density
Rated Capacity	Rate-limited, based on dynamic properties – viscosity, withdrawal period
INJ	Injection rate for natural gas, GWh/day
HINJ	Injection rate for hydrogen, GWh/day
WIR	Withdrawal rate for natural gas, GWh/day
WHIR	Withdrawal rate for hydrogen, GWh/day
TWh	Unit of energy, terawatt-hours, 10^{12} watt-hours
GWh/day	Unit of power, gigawatt-hours/day, 10^{9} watt-hours/day
WGC	Working gas capacity, TWh
CUG	Cushion gas, TWh
TOG	Total gas, WGC+CUG, TWh
WGC-ED	Capacity for H_2 based on energy density, TWh
WGC-NG	Capacity for natural gas, TWh
WGC-90	Capacity for H_2 based on 90 days of withdrawal, TWh
GIE	Gas Infrastructure Europe
IGU	International Gas Union

1. Introduction

This report details the results of an assessment of European hydrogen storage in porous reservoirs. Specifically, the potential storage capacity and performance of existing underground gas storage sites when converted to hydrogen. Hydrogen can potentially be stored as a compressed gas in porous reservoirs at typical depths of 1-3 km and 10-30 MPa (Juez-Larré et al., 2019). To date, hydrogen has been stored for decades in salt caverns as a feedstock and hedge against supply disruption for the chemical industry both in the USA and UK (Cihlar et al., 2021, Wolf, 2015). Storage volumes are 0.01 to 0.1 bcm, equivalent to 28 to 280 GWh (ISO 13443 standard conditions, LHV), which is relatively small compared to the terawatt-hour volumes required to secure energy supply across seasonal variations in demand. Europe consumes 5,000 TWh of natural gas annually and has an underground storage capacity of 1,500 TWh, or 30% of the annual natural gas demand, of which salt caverns provide 185 TWh, 12 % (GIE, 2021). While estimates vary widely, the required hydrogen underground storage capacity forecast for Europe as part of a net zero transition falls within the range 250-1000 TWh by 2050 (FCH JU, 2019, Cihlar et al., 2021, van Rossum et al., 2022). Realising storage capacity at this scale with salt caverns alone will face serious technical, environmental, and spatial planning constraints (Cihlar et al., 2021).

Given the capacity envisioned, hydrogen storage in porous reservoirs will play an important role and will likely be dominated by depleted gas reservoirs if the European natural gas storage experience is repeated – 84% of current porous reservoir storage is in depleted gas fields, which makes sense given their proven containment, inherited cushion gas, and networked status (GIE, 2021). While hydrogen storage for energy balancing is an emerging sector, natural gas storage demonstrates the feasibility at scale, and town gas storage provides a valuable 20th century experience of hydrogen-rich underground gas storage. The history of natural gas and town gas are briefly profiled in the background section that follows.

The aim of this report is to summarise the location and capacity of existing gas storage available for conversion to hydrogen storage. This is accomplished through a review that identifies these resources by region and country, having established the general distribution and approach. We have documented the outcomes as a 'long list' spreadsheet of sites by location, working gas capacity, and the associated metrics of injection and withdrawal rates – Appendix A. Notably, we have provided two estimates for working gas capacity: a static capacity estimate based on energy density (WGC-ED). This is a common heuristic, equivalent to 0.25x natural gas storage capacity. The second heuristic, a rate-dependent capacity, is based on the withdrawal period which averages 90 days for European storage sites (WGC-90). This is equivalent to 0.5x natural gas storage capacity, a function of the much higher deliverability associated with hydrogen's lower viscosity, which partly compensate for the lower energy density. Both approaches are documented in detail in the methodology section. The WGC-ED and WGC-90 conversion factors provide a conservative upper and lower range with respect to capacity, a first approximation that can be refined with detailed site analysis and reservoir engineering for short-listed sites of high interest.

The review that accompanies the methodology is in two parts. The first part, Chapter 3, addresses general themes and trends evident in the public databases - GIE and IGU - the principal information resources for European gas storage. The apparent themes and trends are addressed by reservoir type and regional distribution. Briefly, the resource is dominated by natural gas storage sites, primarily depleted gas fields, as almost exclusively documented in these two databases. The countries are then reviewed, and capacity conversion heuristics applied for sites in the identified regions, documenting the hydrogen storage of available resources – Chapter 5. The report closes with a summary of the main metrics, and outcomes.

2. Background

The history of European underground gas storage can be summarised as provincial town gas in the middle of the 20th Century and networked natural gas in the late 20th and early 21st Century. These important precursors to hydrogen storage are briefly summarised below. They provide a context for the approach taken in this report which emphasises the abundant reserve of proven gas storage facilities available for conversion, as well as emerging hydrogen storage pilots and prospects that represent additions to the existing reserve.

2.1 Town Gas

The early European experience of underground gas storage is dominated by the coal industry and town gas. Metropolitan gas networks date back to the early 19th Century with the introduction of gas lamps for London street-lighting in 1807 (Thomas, 2014). Gas heating followed by mid-century, with further local diversification into many industrial uses such as refrigeration, coffee roasting, and boilers. Town gas, a flammable mixture of methane, hydrogen, carbon-monoxide, carbon-dioxide, nitrogen and trace gas impurities, was a by-product of coal coking at processing sites that became known in cities across Europe as the gasworks. This hydrogen-rich gas became a versatile energy commodity by the end of the 19th century, and was stored underground in salt caverns, abandoned mines, and aquifers from the 1950s onwards as exploration programmes identified geological storage near provincial and national pipelines but away from rapidly growing urban areas (Evans & West, 2008).

Coal-rich areas across Europe, from Poland to Belgium, northern France, and the UK, pioneered early underground gas storage in porous reservoirs, for example at Beynes, Île de France, from 1952, 33% hydrogen, and Lobodice, Czechia from 1965, 54% hydrogen (Liebscher et al., 2016). While no significant safety or environmental issues are reported in the literature, the Lobodice experience documents that approximately half of the hydrogen altered to methane, which was attributed to microbial activity – anaerobic microbes feeding on hydrogen and available carbon sources, CO and CO_2, to produce methane (Panfilov, 2010). Increased concentrations of hydrogen sulfide, H_2S, were also observed in Beynes – both abiotic and biotic pathways have been proposed for this (Smigai et al., 1990; Panfilov, 2016; Bourgeois et al., 1979; Hassanpouryouzband et al., 2022). Town gas was eventually displaced in the late 1960s by cheaper and cleaner 'natural gas', initially with imports of liquid natural gas (LNG) from Algeria and America; then, domestic supplies on the discovery of giant onshore and offshore gas fields in France, the Netherlands, and the North Sea (Evans & West, 2008).

2.2 Natural Gas

Natural gas from hydrocarbon fields was first harnessed as a by-product of oil production and diverted into gas-fired boilers at Schodnica in Poland, now Ukraine, in 1896 (Krzywiec, 2018). By the early 20th century, natural gas from oil wells was routinely diverted into local town gas networks across Europe. However, natural gas began to displace town gas in the 1950s with the discoveries of the giant and supergiant gas fields of Lacq, France, and Groningen, Netherlands. This was followed by the offshore discoveries of Viking and P6 in the southern North Sea in the late 1960s. The energy market rapidly pivoted to a trans-European natural gas network with the emergence of this abundant, cheaper, and cleaner alternative.

Since then, hundreds of gas fields have been discovered across Europe – there are over two hundred fields in production in the Netherlands alone, ninety-one of those onshore; the UK offshore fields number one hundred and eighty-six. A relatively small number of depleted gas fields across Europe, 118, have been repurposed as storage sites. For example, the Netherlands has four, all onshore with three amongst the largest in Europe: Alkmaar (5 TWh),

Bergermeer (48 TWh), Grijpskerk (28 TWh) and Norg (59 TWh). The UK had one large site, the offshore Rough gas field (30 TWh), which has recently closed but is being reconsidered for hydrogen storage. The average storage capacity for Europe is 9 TWh (GIE, 2021).

The existing European natural gas storage reserve broadly reflects the global distribution of 80% storage in depleted gas fields, 12% in aquifers, and 8% in engineered salt caverns (Tarkowski, 2019). The dominance of depleted gas field storage reflects the inherited cushion gas, the proven gas storage efficacy, and an established connection to the distribution network. The European natural gas storage capacity for operational sites is 1513 TWh: 1,121 TWh in depleted gas fields (74%), 207 TWh in aquifers (14%), and 185 TWh in salt caverns (12%). The relatively high percentage of salt cavern storage reflects the excellent Southern Permian Basin resource which is predominantly located in northern Germany. The total operational storage capacity provides 30% of the annual European demand which is currently 5,000 TWh, equivalent to 10 MWh of demand and 3 MWh of storage per person for 500 million citizens (Egging et al., 2019). A further 296 TWh of storage is planned, 136 TWh in depleted gas fields, and 160 TWh in salt caverns (GIE, 2021).

Most countries in Europe appear to lie close to the 30% storage vs. demand trend line – Fig 2. Note that six countries (Germany, UK, Italy, France, Netherlands, and Spain) have significantly higher demand, reflecting large populations and industrial activity, and mostly adhere to the 30% trend. The UK and Spain are notable outliers, having opted for just-in-time supply strategies. This is discussed in more detail in the review section. Excluding salt cavern storage, natural gas storage in porous reservoirs is closer to about 25% of demand, or 1,250 TWh.

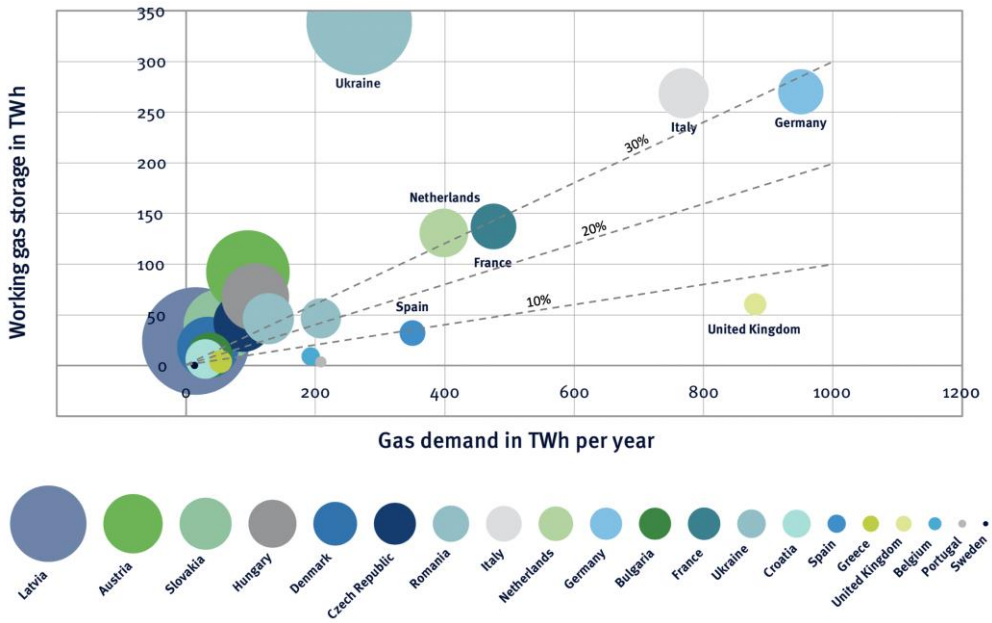


Figure 2. Natural gas storage versus demand for Europe. Spain and the UK have the lowest storage among the big six. Italy and Austria are notable for high storage relative to demand. Latvia is an outlier with respect to demand but acts as a balancing centre for the Baltic region. The notable outlier is Ukraine with the largest capacity in Europe, 339 TWh. Bubble size represents the ratio of storage capacity to demand. (Adapted from Speirs et al., 2020).

2.3 Hydrogen Demand and Storage

Forecasts for hydrogen demand and storage in 2050 vary widely. The following list is not exhaustive but gives a sense of the range - all estimates are rounded to the nearest 50 TWh. The Guidehouse reports, summarised below, estimate 2,000 TWh of demand and 450 TWh of storage (25%) for the same twenty European countries featured in Fig 2, and 2,300 TWh for

the EU27 plus the UK (Cihlar et al., 2021). A recent doctoral thesis on hydrogen estimated less than 700 TWh of demand and 150 TWh of storage (20%) for the EU27 plus UK, Norway, and Switzerland (Caglayan, 2020). Finally, the EU roadmap for hydrogen estimates 2,250 TWh as an ambitious target; the low-end BAU demand estimate is less than 800 TWh (FCH JU, 2019). This project, HyUSPRe, has estimated a 4,000 TWh 2050 demand as a baseline scenario supported by a detailed system-wide analysis of Europe – Fig 3 (Groß et al., 2022).

While each of the above analyses has its merits and differences, a pragmatic approach would be to assume a mid-range value that aligns with the Guidehouse reporting, while remaining aware of the spread. As such, this report assumes a 2050 demand of 2,500 TWh for Europe as a whole and 20% storage as a conservative limit, equivalent to 500 TWh. A high-end estimate of 4,000 TWh and 25% storage doubles the storage requirement to 1,000 TWh, while a low-end demand of 750 TWh and high 30% storage halves the amount to 250 TWh. This simple approximation frames the demand and highlights the uncertainty.

In summary, the general values cited above suggest a range of possible outcomes. The ambitious EU vision for hydrogen demand is likely to be comparable by order of magnitude to the current natural gas demand of 5,000 TWh. The latter is currently supported by approximately 25% or 1,250 TWh of porous reservoir storage. It follows that a mid-range estimate of 2,500 TWh of hydrogen demand would require an equivalent storage capacity of 625 TWh, slightly higher than our conservative mid-range value of 500 TWh at 20% storage. And so, the mid-to-high range storage requirement likely falls between 500 and 1,000 TWh.

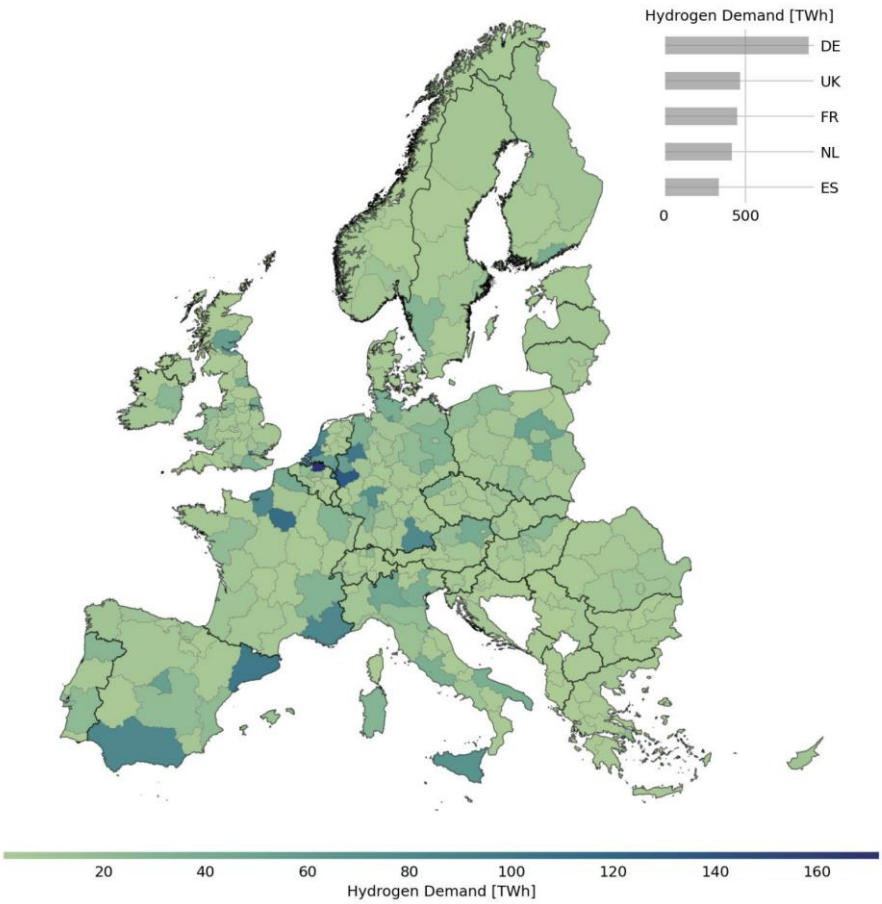


Figure 3. HyUSPRe hydrogen demand for 2050. The total demand forecast is 4,000 TWh +/- 25%, with approximately half of that demand concentrated in five countries (Groß et al., 2022). Note the high demand around industrial port cities, dense conurbations, and manufacturing areas.

2.4 Conversion

A common conversion heuristic for capacity based on hydrogen's relatively low energy density, 1/4 that of natural gas – presented in detail in the methodology section – would imply that this requires 2x the current volume of storage, or 200 hydrogen sites for every 100 natural gas sites. However, a rated capacity heuristic, 1/2 that of natural gas – also presented in the methodology section – suggests that the current volume of natural gas storage is sufficient if converted. The high end of the range, 1000 TWh, would still require a doubling of current capacity. In other words, a neighbouring site of equivalent capacity would need to be found for each existing site.

2.5 Long List

This framing of the problem with respect to required storage capacity helps put the excessive outcomes of recent storage resource estimates in context. For instance, Caglayan (2020) estimated that the potential European resource for salt was 85,000 TWh. Mouli-Castillo et al. (2021) estimated more than 2,650 TWh of hydrogen storage potential in the UK alone for a short-listed set of 48 North Sea depleted gas fields, noting that several of the studied fields could, as a single storage site, meet the entire forecast UK demand of 80 TWh (Speirs et al., 2020). The average capacity for the 48 fields was 55 TWh, which clearly departs from the historic experience of gas storage in depleted gas fields across Europe at an average capacity of 9 TWh. The Netherlands has a similar abundance of resources: comparing three operational storage sites in the Netherlands, and three proposed offshore UK storage sites, it is difficult to distinguish these large 20-60 TWh sites in small-to-moderate-sized gas fields from the many similar-sized depleted gas fields that surround them – Fig 4.

Such a broad theoretical resource base, which is replicated across Europe, and runs to hundreds of thousands of terawatt-hours, presents a problem. How to identify a long list of potential storage sites that have a high relevance and low threshold to entry from the extraordinarily large resource base?

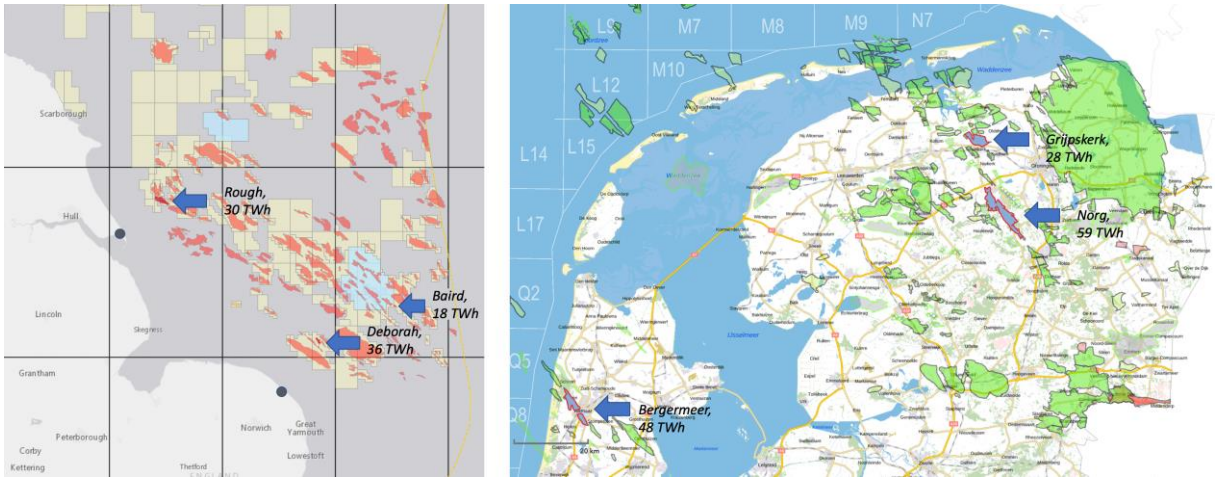


Figure 4. Large storage sites in context. The Rough storage site, 30 TWh, and proposed storage sites of Deborah and Baird, 36 and 18 TWh, are difficult to spot amongst the many similar depleted gas fields of the UK's southern North Sea. Norg, 59 TWh, Bergermeer, 48 TWh, and Grijpskerk, 28 TWh, are amongst the largest storage sites in Europe, but difficult to distinguish from similar depleted gas fields in the Netherlands. (Note that the UK fields are the very small, mapped outlines directly next to the indicator arrows, not the larger fields close to the arrows).

Given the available resource, this report has emphasised the conversion potential of existing gas storage sites, which are proven stores networked to demand centres and with known capacities and performance metrics. These conversions make up 99% of the long list included as an appendix, and potentially exceed the 2050 forecast storage requirement of 500 TWh by 150 to 250 TWh (WGC-90) – the lower value represents operational conversions; the upper value includes planned sites. Where data is available, the long list has been augmented with additions, representing hydrogen storage pilots and prospects that have not previously been gas stores. This small contribution of declared additions reflects the emerging state of exploration for new porous reservoir capacity and the highly commercial and sensitive nature of such assets.

2.6 Guidehouse Reporting

Guidehouse, a research consultancy based in the Netherlands, has recently published, and contributed to several reports on the hydrogen transition, three of which address storage. The storage reporting represents the perspectives of GIE (GIE, 2021), Gas For Climate (Wang et al., 2021), and the European Hydrogen Backbone initiative (van Rossum et al., 2022). These three networks articulate the natural gas industry's transition strategy and lobby this strategy to the European Parliament and regulators. The Guidehouse reports make a number of salient points about European hydrogen storage worth repeating here.

Firstly, the reports note the relatively cheap cost of seasonal hydrogen storage, recognising "the importance of hydrogen storage and the benefits it provides in the context of renewable energy integration, security of supply, and connectivity and costs of the wider system" (Wang et al., 2021). The reports also anticipate a mixed portfolio of hydrogen storage for Europe, including depleted gas fields, salt, and aquifers, in that order, reflecting the current status quo with respect to natural gas.

The 2021 Guidehouse report by Cihlar et al. (2021) provides a quantified storage analysis that estimates the first-order hydrogen capacity requirement as 450 TWh by 2050, equivalent to 24% of demand across 21 countries. This aligns well with our mid-range 500 TWh estimate for the wider European context.

The Guidehouse analysis identifies a significant potential shortfall in hydrogen storage capacity. This firstly reflects an unquantified assumption that natural gas remains as a fractional contribution to European energy demand out to 2050, and therefore retains a portion of the storage capacity it currently occupies. Secondly, this also reflects a conversion capacity estimate based on the energy density heuristic described earlier. The Guidehouse report's first-order approximation of the available conversion capacity is 265 TWh, i.e. one quarter of the existing capacity, of which salt is expected to contribute 50 TWh (van Rossum et al., 2022). Based on the difference between the anticipated 450 TWh requirement and 265 TWh availability of conversion capacity, the report concludes that an extensive exploration and expansion programme is required to create additional capacity in salt caverns and porous reservoirs to meet demand (Cihlar et al., 2021).

We arrive at a similar shortfall when applying the same energy density heuristic, which represents a conservative lower limit of available capacity. However, this shortfall may be substantially addressed by applying a rated-capacity conversion heuristic, a conservative upper limit, which indicates that the available capacity may be sufficient for the mid-range capacity requirement estimate of 500 TWh. This alternative approach is addressed in detail in the methodology section.

3. Review

The European potential for developing hydrogen storage capacity is primarily located in to-be-converted existing natural gas storage facilities, which are dominated by depleted gas fields, as almost exclusively documented in the GIE database (GIE, 2021). This significant database is reviewed in detail below. Where data gaps exist, e.g., cushion gas generally, working gas capacities for aquifer sites in France, depleted gas fields in Italy and Hungary, these have been largely addressed by recourse to the global IGU database (IGU, 2022). The initial review is by reservoir type and general distribution and can be briefly summarised in one map – Fig 5. This identifies regions of interest, which are addressed in the results section below.

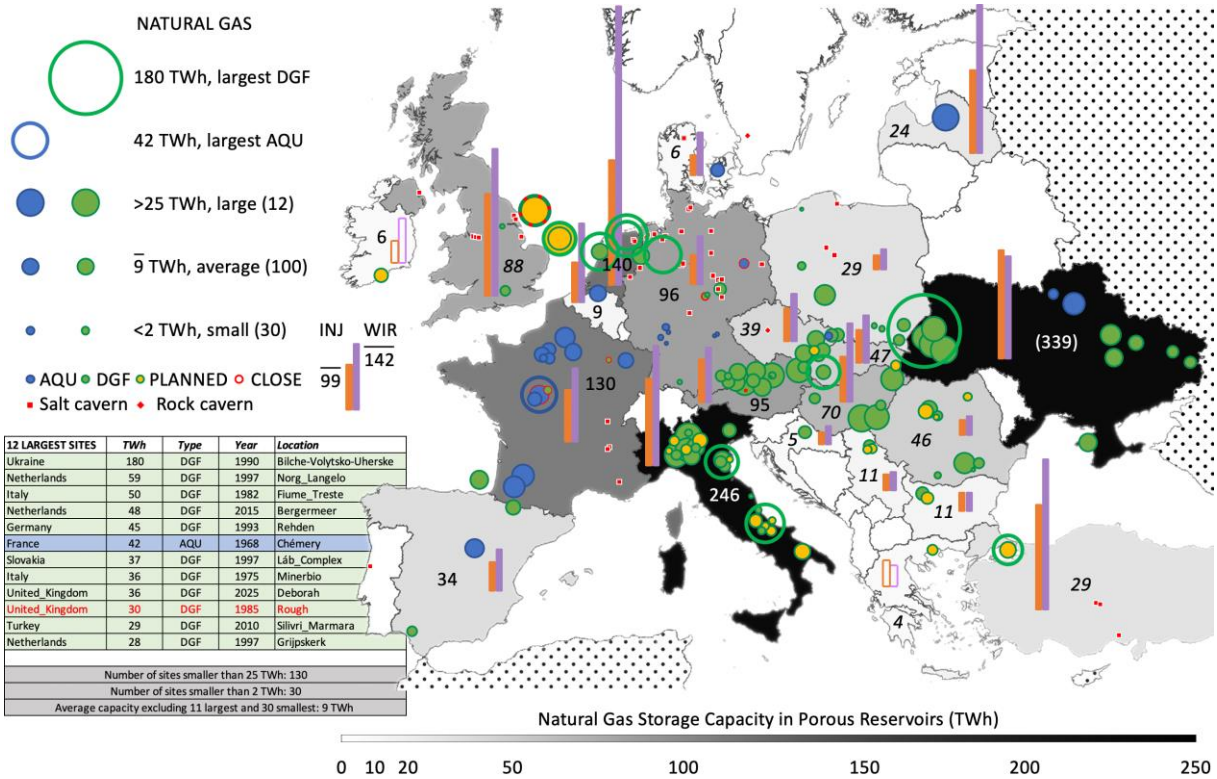


Figure 5. European natural gas storage by size, location, and type. The bubbles represent entries in the GIE database and indicate strong themes with respect to distribution. Depleted gas field sites follow the petroleum system fairway trend from the Irish Sea to the Black Sea. Large storage sites are concentrated in northwestern and central Europe, Italy, and Ukraine, and are almost exclusively depleted gas fields. There are notable clusters off this trend: the industrial zone of northern Italy, large aquifer storage sites of France, the large Soviet-era aquifer in Latvia. The Spanish aquifer site is the only recent addition to aquifer storage. The twelve largest sites appear as rings and are documented in the table. Solid circles represent sites smaller than 25 TWh. Excluding the very large Ukrainian site, 180 TWh, the average capacity for remaining large sites is 40 TWh. The scaled coloured bars represent injection (orange) and withdrawal rates (purple) for each country, which average 99 and 142 GWh/day.

3.1 Databases

Our research has relied on two public databases for much of the analysis. The main resource has been the GIE storage database which is a free web-hosted inventory that has documented the existing portfolio of gas storage sites across Europe for over a decade as part of Gas Infrastructure Europe's mission since 2005 to provide transparency and insight about the vast gas network that encompasses and extends across Europe and beyond the European Union. Gas Infrastructure Europe (GIE) are a networking organisation based in Brussels that provides coordinated lobbying to the European Parliament and gas regulators for its 68 member companies which operate across 27 countries.

The GIE storage map is a visual representation of the database, released every two years, providing a comprehensive view of the European network and storage distribution (GIE, 2021). Where data gaps exist, these have been largely addressed by recourse to IGU database, a similar global resource published for free by the International Gas Union (IGU, 2022). The following section addresses general themes and metrics relating to the GIE 2021 map and database.

3.2 Trends

The general distribution of natural gas storage across Europe reflects both the regional demand and available geology. For example, large storage sites are found close to regionally strategic locations of gas production such as Groningen, Netherlands, and Olesska, Ukraine. At the other end of the demand spectrum, regions of high population density and industrial activity are also associated with storage clusters if the geology is suitable, such as in Austria, and northern Italy. Elsewhere on the network, sites are strategically located to buffer storage ingress and egress at ports and close to national borders, such as found in Spain and Latvia. Almost all the gas storage sites are onshore. The UK, Spain, and Turkey are the exceptions.

With respect to geology, the majority of storage sites are depleted gas fields which lie along a great circle trend line from the East Irish Sea to the Bosphorus Strait, connecting Rough in the southern North Sea to the large storage sites of the Netherlands and northwestern Germany, and the clusters of similar sites in southern Germany, Austria, central Europe, Ukraine, Romania and Turkey. Away from this axis, the majority of salt cavern storage is found in northern Germany, the Netherlands, and Denmark, reflecting access to the thick Zechstein deposits of the Southern Permian Basin. The highest concentration of depleted gas field sites and salt caverns is found in northwestern Europe, reflecting both the industrial base, high population density, proximity to production and suitable geology.

France is exceptional, as its giant gas fields in the south are not associated with gas storage. The giant gas fields of the Aquitaine basin are deep, over-pressured, and contaminated with H_2S, a highly toxic trace gas. France also has a tradition of centralised and socialist infrastructure projects which underwrote the construction of large aquifer sites in the 1970s to support their self-sufficiency in natural gas. A separate north-south axis of three salt cavern sites is found along the Rhône valley.

Beyond France, Latvia has a large Soviet-era aquifer storage site, reflecting its terminal port status for Russian and Ukrainian gas prior to the construction of Nord Stream in 2011. Ukraine has two storage clusters: one in the east, supplying Russia, and one in the northwest near Poland, supplying Europe. Spain has the only recently built aquifer site, 12 TWh, a recently identified exploration prospect with ideal qualities for gas storage which became operational in 2012. Prior to that, Denmark's Stenlille store, 6 TWh, was the only aquifer site constructed in western Europe since the EU was founded in 1993. There are currently no aquifer sites planned across Europe.

Spain and the UK are notable for their low gas storage provision – Fig 2. Both have had privileged access to natural gas markets in the past: the North Sea for the UK, and North Africa for Spain. The abundance of reserves in these two regions since the 1960s supported an independent approach to gas supplies and storage. Spain has been isolated on the Iberian Peninsula by mid-20th century politics and the physical geography of the Pyrenees. Both countries have also had a historic reliance on liquid natural gas, which has increased in recent decades. Interestingly, both countries are extremely well resourced with respect to green hydrogen – offshore wind for the UK, solar and wind for Spain – which may lead to a significant increase in storage provision and hydrogen network connections in the near future.

3.3 Metrics

Screening out the 84 salt cavern and 2 rock cavern entries in the GIE database, 143 of 230 entries remain: 117 depleted gas fields and 26 aquifers. Some brief metrics on natural gas:

- 108 of the 143 porous reservoir site entries in the database are operational, 1956-2021. Half the sites have been constructed since 1988. The operational capacity is 1328 TWh.
- Ukraine has the largest depleted gas field site by far, 180 TWh. The next largest is in the Netherlands, 59 TWh. France has the largest aquifer site at 42 TWh.
- Germany has the most storage sites: 45 salt caverns, 10 depleted gas fields, and 6 aquifers. Germany's porous reservoir storage capacity is 96 TWh.
- France has the most aquifers, 11 in total, plus 2 depleted gas field, both closed.
- Italy has the largest number of operational depleted gas fields, 13, mostly concentrated in the industrial north, followed by Germany with 10, and Austria with 9.
- Slovakia and Hungary are notable for having large storage sites in depleted gas fields, 37 and 24 TWh respectively – both post-Soviet era, opened in 1996 and 1997.
- Czechia is notable for a cluster of storage sites in depleted oil fields as well as gas fields.
- The average capacity of porous reservoirs is 9 TWh, compared to 4.5 TWh for salt. Excluding Chémery in France, 42 TWh, the average aquifer capacity is 6 TWh. Excluding the 11 largest depleted gas fields, 28-180 TWh, the average for depleted gas is 7 TWh.

In summary, three trends are evident:

- A northwest-southeast trend of depleted gas field storage from the UK to Turkey
- A northeast-southwest trend of aquifer storage from Latvia to Spain
- An industrial cluster of depleted gas field storage in northern Italy

A small number of countries have in excess of 100 TWh of storage. Ukraine is exceptional, with the largest storage site and inventory in Europe which totals 339 TWh. This speaks to its long history of supplying gas to Europe and Russia since the early 20th Century. Italy is second only to Ukraine for porous reservoir storage, at 197 TWh, reflecting its reliance on gas over coal for domestic energy consumption and high energy demand in the industrial north. Germany is notable for its high reliance on salt caverns, 162 TWh, which in addition to its porous reservoir storage gives it the second largest total storage inventory in Europe at 258 TWh. Austria is at the centre of a dense cluster of depleted gas field storage sites in central Europe which also encompasses southern Germany, Czechia, and Slovakia and accounts for 212 TWh of depleted gas storage in an area the size of the Netherlands. The Netherlands, at 140 TWh, has the largest storage capacity by land area for a single country. The high concentration reflects its central role in balancing the European gas network with gas from Groningen, the supergiant gas field. France, at 131 TWh, centrally planned for aquifer storage in the mid-20th Century to provide energy security given the abundance of domestic natural gas discovered in the 1950s.

The following section addresses the two methods for converting the existing natural gas capacity to hydrogen storage potential as applied in this study.

Table 1: Natural gas storage distribution by country and type, count (upper table) and capacity (lower table).

NATURAL GAS		Operational			Planned			Closed			Total
Country	**Code**	**DGF**	**AQU**	**Total**	**DGF**	**AQU**	**Total**	**DGF**	**AQU**	**Total**	**Total**
Belgium	BE		1	1							1
Denmark	DK		1	1							1
Germany	DE	10	6	16				1		1	17
Ireland	IE				1		1				1
Netherlands	NL	4		4							4
United Kingdom	GB	2		2	2		2	1		1	5
NW EUROPE		**16**	**8**	**24**	**3**		**3**	**2**		**2**	**29**
Austria	AT	9		9				1		1	10
Croatia	HR	1		1	1		1				2
Czech Republic	CZ	6	1	7	1		1				8
Slovakia	SK	2		2	1		1				3
CENTRAL EUROPE		**18**	**1**	**19**	**3**		**3**	**1**		**1**	**23**
Bulgaria	BG	1		1	1		1				2
Hungary	HU	5		5							5
Latvia	LV		1	1							1
Poland	PL	7		7							7
Romania	RO	6		6	4		4				10
Serbia	RS	1		1	2		2				3
Ukraine	UA	11	2	13							13
EASTERN EUROPE		**31**	**3**	**34**	**7**		**7**				**41**
France	FR		11	11				2	1	3	14
Greece	GR				1		1				1
Italy	IT	13		13	16		16				29
Spain	ES	3	1	4							4
Turkey	TR	2		2	2		2				4
SOUTHERN EUROPE		**18**	**12**	**30**	**19**		**19**		**1**	**3**	**52**
Total		**83**	**24**	**107**	32		32	3	1	6	140

NATURAL GAS		*Operational*			*Planned*			*Closed*			*Total*
Country	**Code**	**DGF**	**AQU**	**TWh**	**DGF**	**AQU**	**TWh**	**DGF**	**AQU**	**TWh**	**TWh**
Belgium	BE		9	9							9
Denmark	DK		6	6							6
Germany *	DE	92	4	96				2		2	96
Ireland	IE				6		6				6
Netherlands	NL	140		140							140
United Kingdom †	GB	4		4	54		54	30		30	88
NW EUROPE		**236**	**19**	**255**	**60**		**60**	**32**		**2**	**345**
** Germany has 45 salt caverns at 18 locations, 162 TWh, and two planned sites, 6 TWh*											
Austria	AT	95		95				0.02		0.02	95
Croatia	HR	5		5	0.29		0.29				6
Czech Republic	CZ	36	2	38	0.43		0.43				39
Slovakia	SK	43		43	4		4				47
CENTRAL EUROPE		**180**	**2**	**182**	**4**		**4**				**186**
Bulgaria	BG	6		6	5		5				11
Hungary	HU	70		70							70
Latvia	LV		24	24							24
Poland	PL	29		29							29
Romania	RO	33		33	13		13				46
Serbia	RS	5		5	6		6				10
Ukraine	UA	319	19	339							339
EASTERN EUROPE		**462**	**44**	**505**	**23**		**23**				**528**
France	FR		130	130				3	13	16	130
Greece	GR				4		4				4
Italy	IT	197		197	49		49				246
Spain	ES	22	12	34							34
Turkey	TR	24		24	2		2				26
SOUTHERN EUROPE		**243**	**142**	**386**	**55**		**55**		**13**	**16**	**441**
† Rough is included as having hydrogen potential despite closure status											
Total		**1121**	**207**	**1328**	142		142	32	13	47	1500

4. Methodology

This section covers the two capacity estimation methods used in this report, termed here 'static' and 'rated', to estimate the working gas capacity of an existing site upon conversion from natural gas to hydrogen storage. The 'static' conversion factor is based on the physical properties of the two gases and their energy density at standard conditions (WGC-ED). The 'rated' conversion factor is an estimate of the gas produced for a withdrawal period of 90 days (WGC-90). The two methods effectively reduce the documented natural gas capacity by a factor of 4 (WGC-ED) or a factor of 2 (WGC-90). This significant difference doubles the available resource for a rated capacity estimate based on the WGC-90 method compared to the more widely used WGC-ED method. The following sections detail the derivation of these conversion heuristics, followed by a brief summary and comparison of the differences.

4.1 Static Capacity

Recent reporting of the potential hydrogen capacity for converted natural gas storage resources applies a simple static conversion estimate based on energy density and assuming an equivalent volume of gas (Cihlar et al., 2021). The working gas capacity for energy density (WGC-ED) is, to a good first approximation, equal to 0.25x the working gas capacity for natural gas (WGC-NG). The energy density conversion is derived from the difference in calorific value and specific volume for hydrogen and methane:

A: H_2/CH_4, enthalpy of combustion at standard conditions	= 120/50 MJ/kg	[1]
B: H_2/CH_4, relative gravity at standard conditions	= 0.0698/0.555	[2]
A x B: energy density heuristic, 2.4 x 1/7.95	= 0.3	[3]

The WGC-ED heuristic is 0.3x WGC-NG at standard conditions. Most storage is found in reservoirs at 1 to 3 km depth, where the heuristic is 0.25x. At very deep conditions the heuristic returns to 0.3x – see Fig 6. Network pipeline conditions are 5-10 MPa and 15-65°C. Taking a mid-point of 7.5 MPa and 30 °C, this provides a proxy depth equivalent of 750 m below the surface for pipeline network conditions – purple line, Fig 6. The energy density heuristic is compared using a quartic regression fit to a generic plot of energy density with respect to depth for typical offshore and onshore conditions (Hassanpouryouzband et al., 2021):

$$\text{Energy Density, } D_E = 0.3 - 9.20\text{E-}05\, z + 5.05\text{E-}08\, z^2 - 9.85\text{E-}12\, z^3 + 7.05\text{E-}16\, z^4 \quad [4]$$

The range of values for the depth window of interest, 1-3 km, and a network proxy depth, 750 m, suggest that 0.25x is an accurate lower-limit approximation for the working gas capacity conversion factor from natural gas to hydrogen storage.

4.2 Rate-limited Capacity

An alternative approach for capacity estimation based on withdrawal rate arrives at a much higher heuristic factor of 0.4x to 0.5x depending on the withdrawal period. Seasonal gas storage in Europe reflects cheap gas prices during a period of low demand in the summer. The stored gas is then sold on contracts and withdrawn over the winter when demand and prices are high. The winter market lasts approximately three to four months. Very high withdrawal rates deplete the pressure of the site quickly, reducing the amount of gas that can be withdrawn and effectively lowering the site's capacity. The rated capacity increases for long periods of withdrawal, say 4 months, and decreases for short periods of withdrawal which can be as little as 1 month. This variation is reflected in the deliverability of a site, which is a measure of the sustainable rate for the period of withdrawal, expressed as gigawatt-hours per day, GWh/day. The work that pioneered this approach (Amid et al., 2016) assumed a withdrawal period of 120 days for the Rough storage site in the UK – Fig 7.

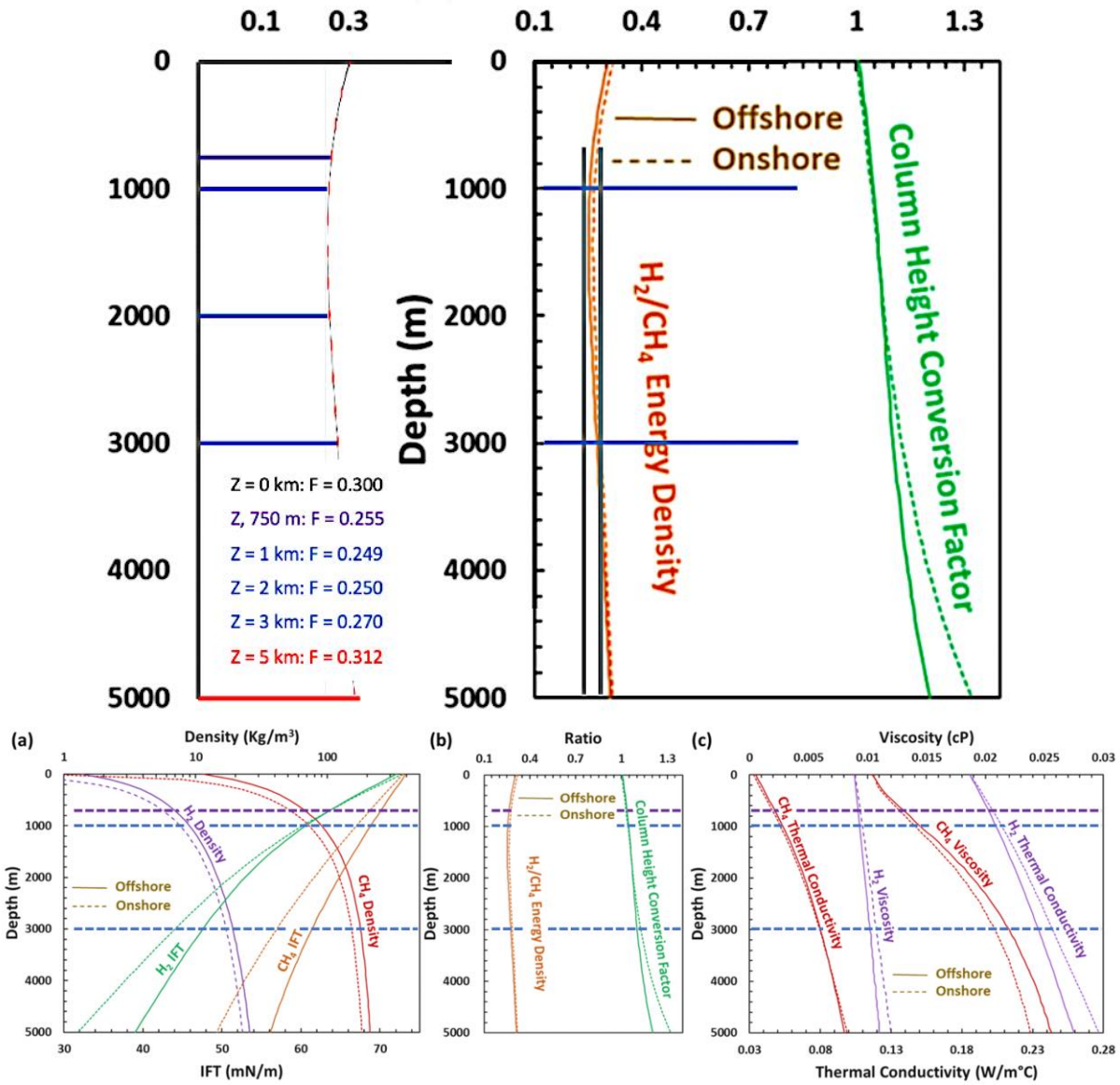


Figure 6: Hydrogen and methane properties. The heuristic factor, F, for WGC-ED takes the form of the quartic regression curve, D_E – left panel. Blue and purple lines show levels of interest. The curve is a simulacrum of energy density vs depth for generic subsurface conditions – right panel and lower panel. Note that the viscosity ratio for hydrogen and methane has a much higher divergence than the other comparison metrics. (Adapted from Hassanpouryouzband et al., 2021).

The difference in deliverability (GWh/day) is primarily a function of viscosity and energy density. Hydrogen has a lower viscosity than natural gas, allowing for more rapid withdrawal. This partially compensates for the lower energy density, increasing the conversion factor to 0.4x. For example, for a methane-hydrogen viscosity difference of 0.016/0.01 cP, the rated capacity conversion factor is as follows:

WGC-120, WGC-ED x viscosity ratio: 0.25 x 0.016/0.01 = 0.4 [5]

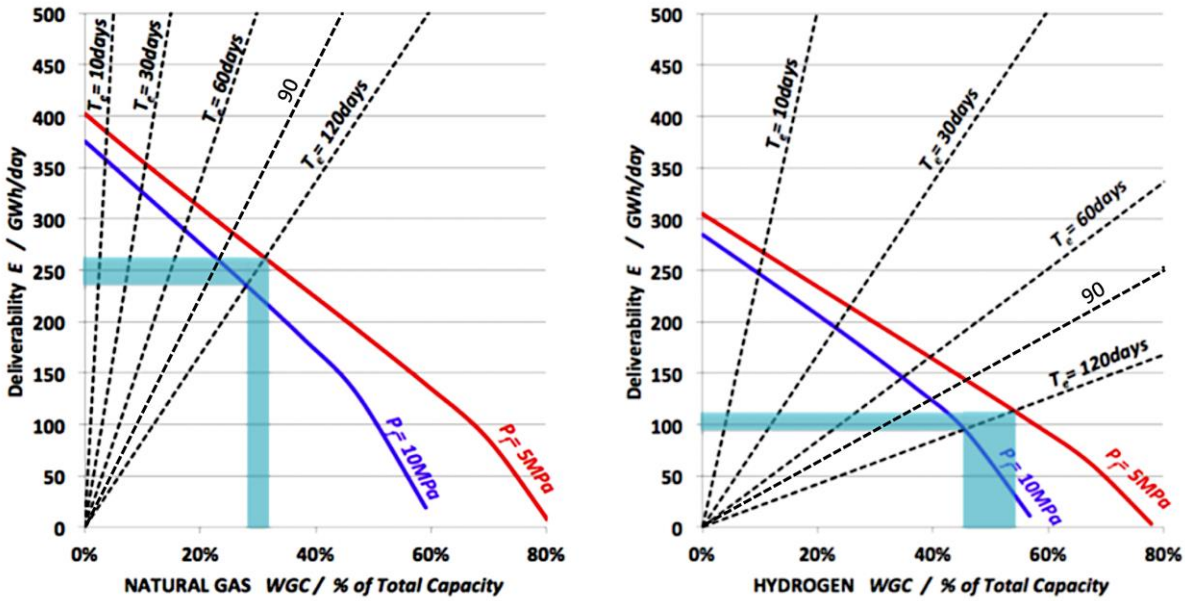


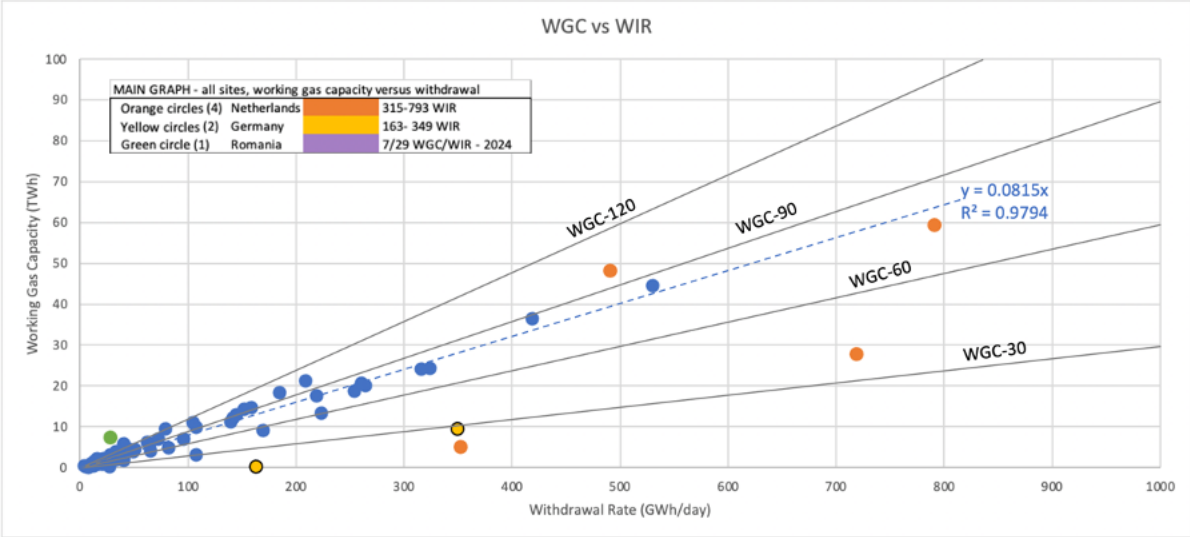
Figure 7: Rated withdrawal for the Rough gas storage facility, United Kingdom (Amid et al., 2016). The red and purple lines represent the operational window for pipeline pressure. The light blue inverted 'L' indexes this window to the axes for a withdrawal period of 120 days. The shorter the withdrawal period, the less efficient the outcome.

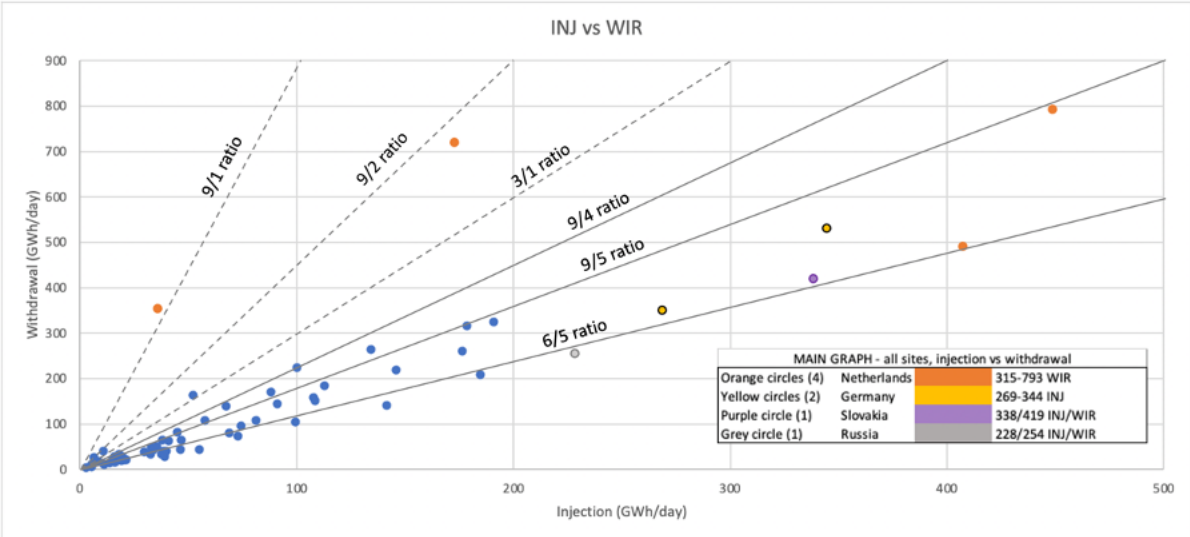
For a generic geothermal and hydrostatic profile, the viscosity ratio and WGC-120 conversion factors are as follows – Table 2:

Table 2: Viscosity ratios and conversion factors for WGC-120 (WGC-ED x Viscosity Ratio). Surface temperature & pressure 10 °C, 101.325 kPa. Geothermal & hydrostatic gradient 30 °C/km, 10 MPa/km.

Depth, m	T, °C	P, MPa	Hydrogen, cP	Methane, cP	Viscosity Ratio	WGC-ED	WGC-120
0	10	0.101	8.59E-03	1.07E-02	1.245	0.30	0.37
100	13	1	8.66E-03	1.09E-02	1.257	0.29	0.37
200	16	2	8.73E-03	1.12E-02	1.280	0.28	0.36
500	25	5	8.94E-03	1.21E-02	1.358	0.27	0.36
750	32.5	7.5	9.13E-03	1.31E-02	1.432	0.26	0.37
1000	40	10	9.31E-03	1.41E-02	1.511	0.25	0.38
1500	55	15	9.69E-03	1.63E-02	1.683	0.25	0.41
2000	70	20	1.01E-02	1.82E-02	1.805	0.25	0.45
2500	85	25	1.04E-02	1.98E-02	1.894	0.26	0.49
3000	100	30	1.08E-02	2.13E-02	1.971	0.27	0.53
3500	115	35	1.12E-02	2.27E-02	2.024	0.28	0.57
4000	130	40	1.16E-02	2.38E-02	2.061	0.29	0.60
4500	145	45	1.19E-02	2.49E-02	2.091	0.30	0.63
5000	160	50	1.23E-02	2.59E-02	2.111	0.31	0.66

Analysis of the available data for natural gas storage (GIE, 2021) suggests that 120 days is the exception rather than the rule, with the mean European value being much closer to 90 days for natural gas storage in porous reservoirs – Fig 8. The WGC-90 values also provide injection and withdrawal rate estimates for hydrogen based on the observed natural gas ratio – Fig 9.





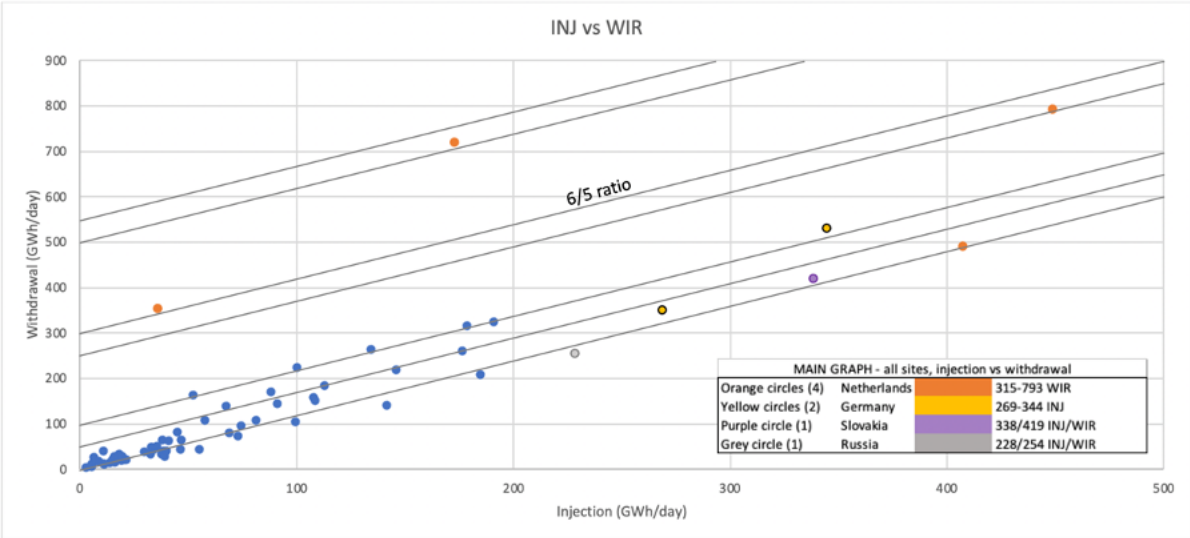


Figure 8. A comparison of working gas capacity and injection and withdrawal rates for long-listed natural gas storage sites. The mean withdrawal period is approximately 90 days; the ratio of injection-to-withdrawal rate ranges between 6/5 and 9/4 for 90% of the sites. The third graph shows the same data interpreted as a fixed ratio, 6/5, with benched levels of minimum withdrawal rates. The radiant and benched interpretations are equivocal.

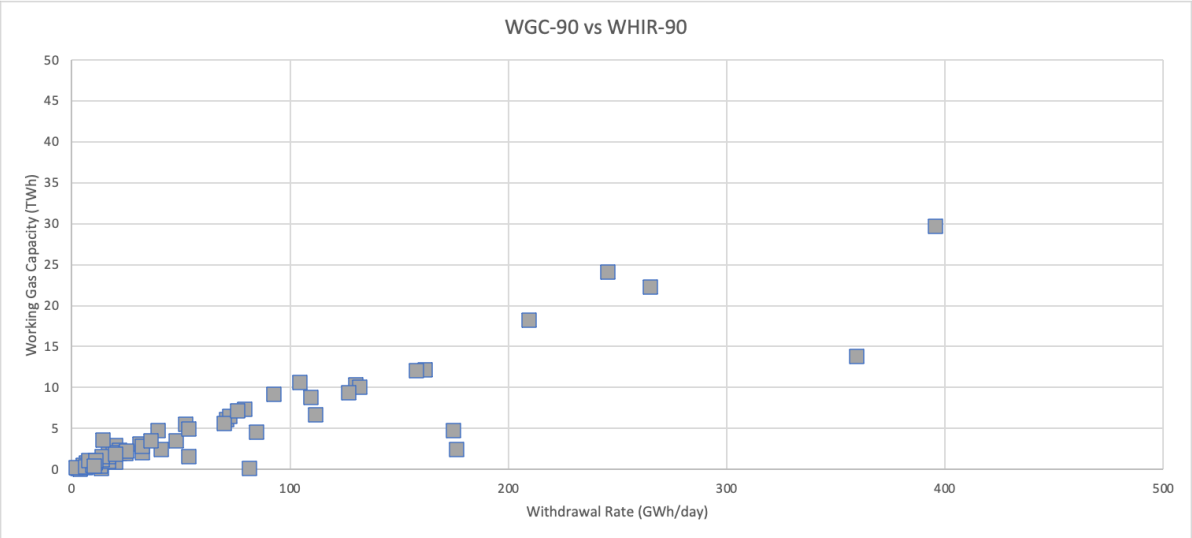


Figure 9. The rate-determined hydrogen capacity (WGC-90) vs hydrogen withdrawal rate (WHIR-90)

Amid et al. (2016) applied a rate-limited capacity approach to the Rough natural gas storage facility in the UK assuming 120 days of withdrawal and demonstrating that shorter withdrawal periods are less efficient – Fig 7. For example, 120 days of withdrawal at 250 GWh/day delivers a rated capacity of 30 TWh. A 60-day period at 300 GWh/day delivers a rated capacity of 18 TWh. It follows that the withdrawal period is crucial for a rate-limited capacity estimate. Adjusting for a 90-day period, the capacity for hydrogen, WGC-90, is 0.5x WGC-NG – Fig 7.

120 days: natural gas deliverability, 250 GWh/day:	120 x 250 = 30 TWh	[6]
120 days: hydrogen deliverability, 100 GWh/day:	120 x 100 = 12 TWh	[7]
WGC-120, conversion factor for H_2 rated gas capacity:	12 ÷ 30 = 0.4x	[8]
90 days: natural gas deliverability, 250 GWh/day:	90 x 290 = 26 TWh	[9]
90 days: hydrogen deliverability, 140 GWh/day:	90 x 140 ≈ 12.5 TWh	[10]
WGC-90, conversion factor for H_2 rated gas capacity:	25/12.5 = 0.5x	[11]

The rated capacity factor of 0.5x for 90 days of withdrawal is assumed to be generally applicable to the long list as a first approximation, providing a conservative upper limit estimate for the conversion capacity (WGC-90). The WGC-90 heuristic is presumed to be a reasonable approximation for the long list documented in this report. Precise factors for each short-listed site in the work to follow will be established by applying the equations and method described by Amid et al. (2016), validated by comparison with an analytical gas storage model based on equations for reservoir in-flow and well flow performance (Juez-Larré et al., 2019; Groenenberg et al., 2021).

5. Results

The general metrics and themes evident in the review suggest a long list of approximately one hundred sites already documented in the GIE and IGU databases that provide a substantial foundation for a hydrogen economy if converted to hydrogen storage. When tabulated, the total number of sites with hydrogen storage potential on the long list equals 140, representing 108 operational, 31 planned, and 1 closed site. The natural gas capacity for the 140 operational, planned, and closed sites sum to 1328, 136, and 30 TWh respectively – Table 1. Much of the planned storage is in the UK, 54 TWh, and Italy, 49 TWh respectively. The conversion heuristics, indicate that the 140 sites potentially provide 373 TWh (WGC-ED) to 747 TWh (WGC-90) of hydrogen storage capacity.

Having established a methodology for conversion, the European resource is now divided into regions and reviewed by countries within those regions – Fig 10. This section documents the known resources, including the GIE and IGU database entries and much smaller number of resources - both conversions and additions - not in these public databases.

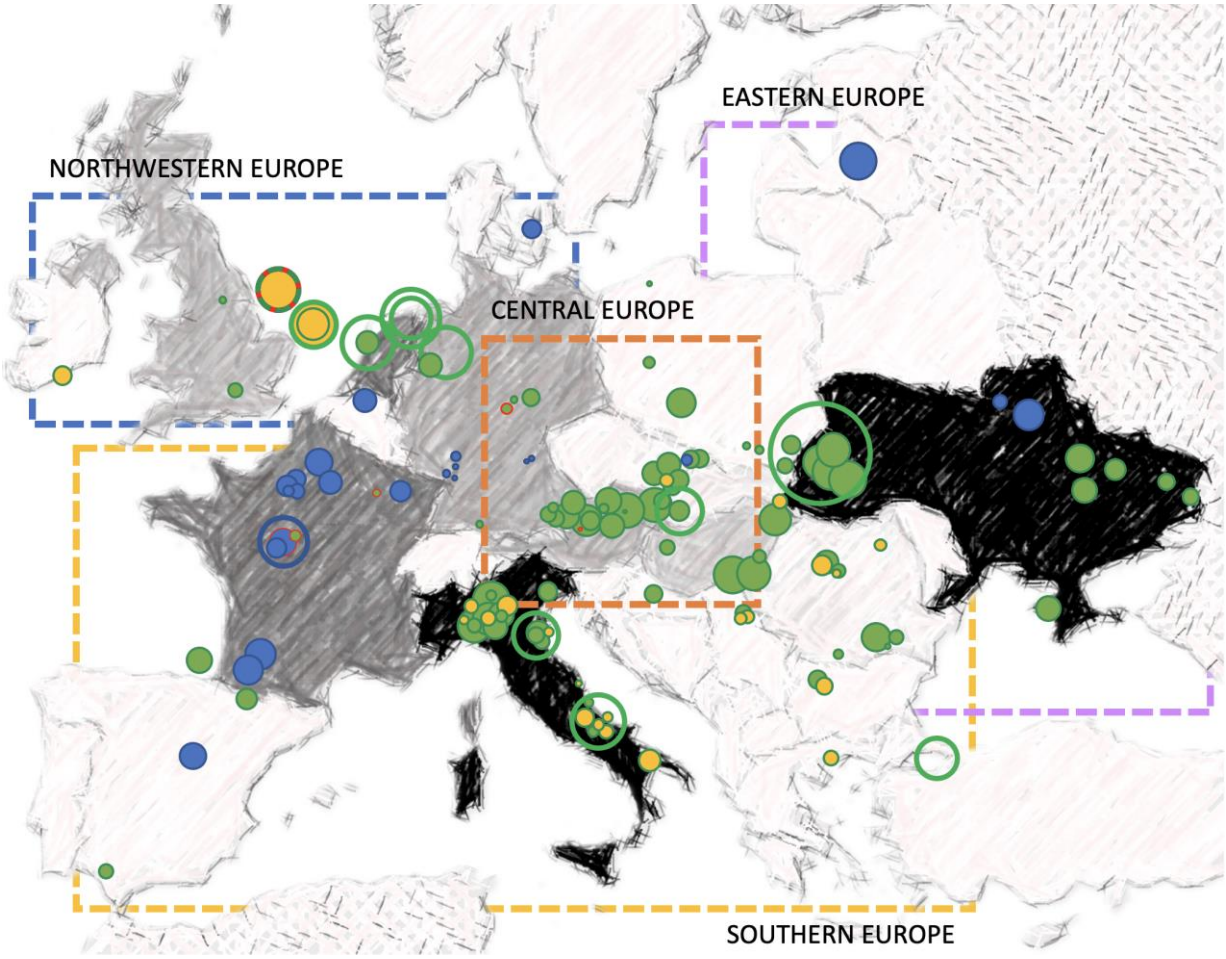


Figure 10. Regional divisions by storage type and location. Planned sites are shown in yellow. Note, there are no planned aquifer sites. The four regions are thematic, each containing a major hub. For the northwest, the hub is the Netherlands. For the south, the axis of French aquifers and cluster of northern Italian depleted gas fields are the hubs. For central Europe, Austria is the hub. For the east, Ukraine is the hub. These regions are reviewed at the country level. Ireland, Kinsale Head, 3 TWh, and Greece, South Kavala, 2 TWh, are the only countries in the database with no operational storage but plans for hydrogen storage.

5.1 NW Europe

The regional reviews identify resources, convert for hydrogen capacity, and document these as a long list appendix of known resources by location and capacity. The long list provides insight and metrics for the summary that closes the report.

5.1.1 Belgium

Belgium has one storage site, an aquifer located in Loenhout, the northern part of Belgium, owned and operated by Fluxys. The seasonal gas storage is in tight carbonate rocks of Dinantian age at a depth of 1300 m. The storage capacity is 9 TWh. The complex geology of Belgium does not offer many options for underground storage in porous formations, hence the potential for hydrogen storage will most likely be limited to the Dinantian aquifer. The potential capacity for hydrogen storage based on conversion of the existing asset is 4 TWh (WGC-90).

5.1.2 Denmark

Denmark has one porous reservoir storage site at Stenlille, in a sandstone aquifer, the Gassum formation, at a depth of 1000 m. Stenlille is located to the southwest of Copenhagen and operated by Gas Storage Denmark. The storage capacity is 6 TWh. Together with Lille Torup, a 4 TWh salt cavern, one third of the Danish annual consumption can be stored underground (GIE, 2021). The potential for developing hydrogen storage capacity in porous reservoirs is primarily in saline aquifers as the majority of Danish hydrocarbon fields are situated in low-permeable chalk reservoirs, which are not suitable for hydrogen storage (Cihlar et al., 2021). Conversion of the Stenlille site would provide 3 TWh of hydrogen storage capacity (WGC-90).

5.1.3 Germany

Germany, like the Netherlands, is notable for its large natural gas storage provision, which is currently the second largest and most diverse portfolio in Europe at a combined capacity of 258 TWh in depleted gas fields, 92 TW, aquifers, 4 TWh, and salt caverns, 162 TWh. This meets 28% of annual demand, reflecting the large population, northern location, cold winters, and a strong industrial base. Unsurprisingly, German gas storage also plays a pivotal role in balancing regional demand, helping to secure the European network in the event of most supply shocks. The distribution of storage sites can be characterised as primarily northwestern (salt caverns and depleted gas fields) and southern (depleted gas fields), with a small cluster of aquifer storage in central Germany – Fig. 11.

It is notable that Germany has only one very large, depleted gas field site, Rehden (45 TWh), built in the mid-1990s, close to, and at around the same time as, the large Netherlands sites. Porous reservoir storage accounts for 38% of capacity, with a regionally disproportionate 62% of capacity in salt caverns, reflecting exceptional access to the onshore distribution of thick Zechstein salt deposits. Six aquifer sites account for less than 5 TWh or 2% of storage. Interestingly, the German data indicates an early mixed portfolio of mainly depleted gas field and salt cavern storage from the 1970s to the 1990s. The last porous reservoir storage site, Uelsen (10 TWh), also a depleted gas field and close to the Groningen cluster, was developed in 1997. Approximately half the salt cavern storage capacity (79 TWh) has been installed since the year 2000 in 24 caverns averaging 3 TWh. The potential capacity for hydrogen storage in re-purposed porous reservoir storage is 48 TWh (WGC-90).

5.1.4 The Netherlands

The Netherlands has six natural gas storage sites: two salt caverns, 5 TWh, and four porous reservoirs, 140 TWh, all of which are depleted gas fields: Alkmaar (5 TWh), Grijpskerk (28

TWh), Bergermeer (48 TWh), and Norg (59 TWh). The depleted gas field sites are operated by NAM and TAQA and located in the northern and western regions of the country. Three of the sites are unusually large relative to the European average of 9 TWh – see Fig. 2. Norg and Bergermeer are among the largest gas storage sites in the Europe – the ten largest depleted gas field sites in the EU average 40 TWh. Storage is at depths ranging from 2000 to 3500 m below the surface. With a combined gas storage capacity of 140 TWh, this constitutes more than one-third of the annual gas consumption in the Netherlands, 400 TWh. The high capacity represents the ongoing role of the Groningen supergiant field as a major natural gas resource for the European network despite its advanced pressure depletion. The large gas storage sites maintain the Groningen supply during periods of high demand. A strong seasonal pattern of net gas imports is observed as the large sites are filled in preparation for high demand periods on the network (FCH JU, 2019).

The Netherlands has the potential to store unusually large amounts of hydrogen too, with a vast portfolio of onshore and offshore depleted gas fields, a strategic location, proximity to the emerging wind farm industry of the North Sea, and a historic role in trans-national network balancing. The existing gas infrastructure could be partly re-used to make the Netherlands a potential hydrogen hub for the European network. A recent study estimated that the potential for Dutch hydrogen storage in all depleted gas fields could exceed 450 TWh, with 280 TWh onshore and 180 TWh offshore, i.e., more than triple the current natural gas storage capacity (Juez-Larré et al., 2019). The existing gas storage sites, when re-purposed, could have a hydrogen storage capacity of 70 TWh (WGC-90).

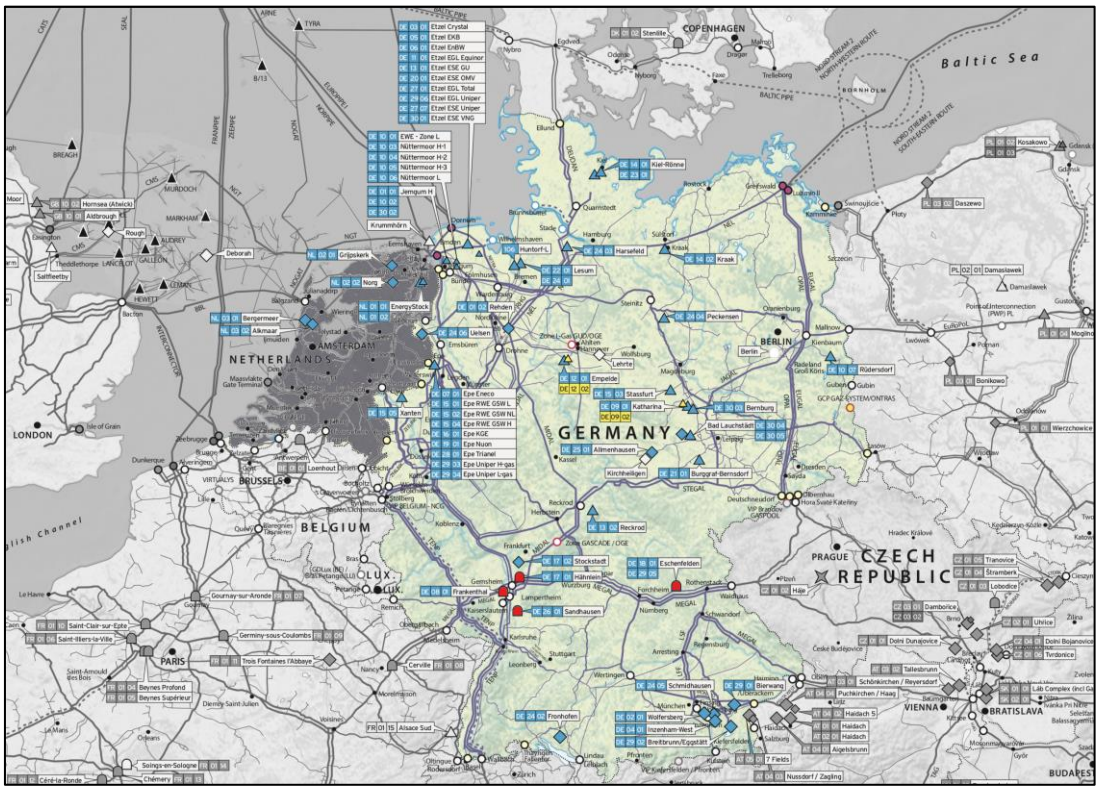


Figure 11. Germany and the Netherlands account for nearly a third of the natural gas storage capacity in Europe. Germany's two largest depleted gas field sites, Rehden and Uelsen (45 and 10 TWh) are close to the Groningen cluster of storage sites in the Netherlands, which includes Grijpskerk and Norg (28 and 59 TWh). Northern Germany is dominated by salt cavern storage with respect to count and capacity (45 sites, 162 TWh). Southern Germany consists of a depleted gas field storage cluster that extends into Austria. There are a small number of aquifer sites across central Germany, highlighted in red, which average less than 1 TWh, developed in the late 1960s and 1970s. All of Germany's capacity since the year 2000 has been developed as northern salt caverns (24 sites, 79 TWh).

5.1.5 United Kingdom

The United Kingdom has a surprisingly small provision for natural gas storage. The current capacity is 15 TWh, or less than 2% of the UK total demand in 2020 at 854 TWh (Speirs et al., 2020). This is less than one seventeenth of Germany's capacity, despite having 80% of the population and 70% of the GDP. Or, one ninth of France's capacity despite similar population size and GDP.

The UK's gas storage capacity has always been low by European standards, reflecting its once-privileged access to production reserves in the North Sea, and more recently, the closure of the main storage site, described below, and related strategic policy decision to rely on just-in-time deliveries. The UK imports around 500 TWh of natural gas annually. In 2020, 58% of imports arrived from the continent via pipeline, of which 55% came from Norway, 2% from the Netherlands, and 1% from Belgium. The remaining 42% was shipped as liquid natural gas, of which 48% came from Qatar, 27% from America, and 12% from Russia (Burton & Ying, 2021).

The small UK storage provision consists of six onshore salt caverns, 11 TWh, and two small onshore depleted gas fields, 4 TWh: Humbly Grove and Hatfield Moor (GIE, 2021). UK planning appears to favour solution mining in the short term over depleted gas field repurposing, with a further 38 TWh of onshore salt cavern capacity scheduled for development (Evans and West, 2008). This would more than compensate for the decommissioning of Rough, a large offshore depleted gas field storage site in the southern North Sea, that operated for over three decades and accounted for 30 TWh or 70% of UK storage capacity for much of the last decade (Amid et al., 2016).

Rough began to be decommissioned in 2017 following concerns regarding the integrity of ageing wells. Rough's cushion gas, 50 TWh, has since been partially sold off, and is expected to be fully depleted by 2023. Recently, the operator, Centrica, has proposed a £1.6bn plan to repurpose Rough for hydrogen storage in the 2030s, which includes securing the existing wells and replenishing the cushion gas. In evidence submitted to the UK Parliament, Centrica anticipate between 150 and 600 TWh of UK hydrogen demand by 2050, and 10 to 40 TWh of hydrogen storage capacity, with Rough potentially providing 10-15 TWh of hydrogen capacity (WGC-90), depending on the licensed storage pressure which may be restricted.

Two neighbouring depleted gas fields, Baird and Deborah, would add a further 27 TWh of hydrogen storage (WGC-90). Rough, Deborah, and Baird are included in this report's long list of porous reservoir storage sites along with Humbly Grove and Hatfield Moor, given the mature contingency of these five sites, including FEED studies for gas storage and consideration for future hydrogen storage. Beyond these five depleted gas fields, recent national reviews have identified a large number of potential gas storage candidates that amount to thousands of terawatt-hours of capacity. The BGS documented six onshore depleted gas fields in 2008 – Albury, Bletchingley, Caythorpe, Gainsborough, Saltfleetby, and Welton - that potentially add 31 TWh of natural gas capacity (Evans and West, 2008). The University of Edinburgh identified forty-eight offshore depleted gas fields from the southern to the northern North Sea that would theoretically add over 2,600 TWh of capacity. This exceeded their own estimate of UK demand at 78 TWh by 33-fold (Mouli-Castillo et al., 2021), with twelve of the fields exceeding this forecasted requirement as sole entities.

Applying a population-based share of European hydrogen storage, the UK (67 of 514 million citizens) would account for 65 TWh of an estimated 500 TWh capacity. A GDP-based share (2.7 of 20.6 trillion USD) amounts to the same. The five long-listed sites for this study indicate a total hydrogen capacity of 44 TWh (WGC-90). The planned salt caverns would increase capacity to 63 TWh (WGC-90).

5.2 Central Europe

5.2.1 Austria

Austria is unusual in that the storage capacity matches the country's annual domestic demand. The high capacity reflects Austria's role as a transit hub for natural gas from the east. The gas is stored and distributed to central and western Europe. Only a fraction of the capacity is for domestic use. The country has nine operational storage sites, all of which are depleted gas fields. In the northwest, close to the German border, six sites are divided into three clusters: the Puchkirchen cluster,17 TWh; the Haidach cluster, 31 TWh, and the 7 Fields cluster, 20 TWh. All three are operated by RAG. Combined with storage in the north-eastern region, operated by OMV, this adds up to a total capacity of 95 TWh. New storage potential is available in neighbouring depleted gas fields. These fields have been in operation since the 1960s, providing good data and an engineering basis for additional storage. The conversion capacity for hydrogen is 47 TWh (WGC-90). RAG has also pioneered hydrogen storage pilots – Fig 12.

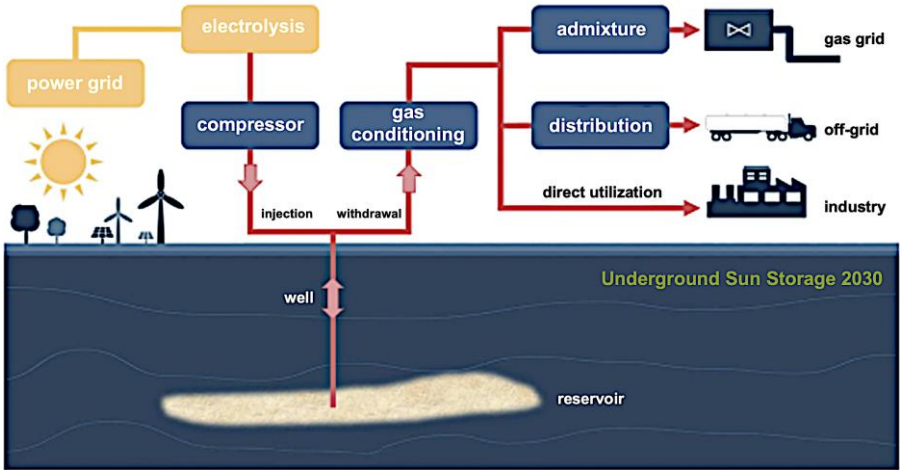


Figure 12. RAG Austria pilot projects have been demonstrating mixed storage since 2013. The Underground Sun Storage pilot demonstrated 10% hydrogen storage at Vöcklabruck (Caglayan, 2020). Two follow-up projects demonstrated 20% storage. A 100% hydrogen project will start operation in 2023.

5.2.2 Croatia

Croatia has one depleted gas field, Okoli, 5 TWh, operational since 1988, and a small neighbouring site planned, 0.29 TWh. The potential for hydrogen is 3 TWh (WGC-90).

5.2.3 Czechia

The Czech Republic has twelve operational sites: one aquifer dating from 1965, 2 TWh, and eleven depleted hydrocarbon fields, with a total capacity of 43 TWh. The eleven are a mixture of gas fields and oil fields with gas caps, mainly clustered in the south-eastern part of the country. The depleted oil fields are excluded from this study. The depleted gas field capacity is 36 TWh. A small 0.43 TWh extension is planned for one depleted gas field, Uhřice. The storage capacity for hydrogen is estimated to be 19 TWh (WGC-90).

5.2.4 Slovakia

Slovakia has two depleted gas field sites at Láb, 43 TWh, which are close to the western border and part of the large central European cluster. A depleted gas site, 4 TWh, is planned on the eastern border. The potential hydrogen capacity is 23 TWh (WGC-90).

5.3 Eastern Europe

5.3.1 Bulgaria

Bulgaria has a single storage site, Chiren, near the northwest border: a depleted gas field, 6 TWh, with a 5 TWh planned extension. The potential hydrogen capacity is 5 TWh (WGC-90).

5.3.2 Hungary

Hungary has five storage sites, all depleted gas fields, 70 TWh, distributed across the country. Hajdúszoboszló in the northeast, 18 TWh; Pusztaederics in the west, 4 TWh; and three sites close to the southeastern border including two large sites, Zsana, 24 TWh, and Szöreg, 20 TWh. The storage capacity for hydrogen is estimated to be 35 TWh (WGC-90).

5.3.3 Latvia

Latvia has one site, Inčukalns, a large aquifer store, 24 TWh, inland from Riga. Constructed in 1968, the site buffered natural gas supplies from Ukraine for the Soviet Baltic region. The site continues to stabilise seasonal supplies in the region, meeting domestic winter demand for Latvia, Estonia, northwestern Russia, and, to a lesser degree, Lithuania. The conversion capacity is 12 TWh (WGC-90).

5.3.4 Poland

Poland has ten storage sites, three salt caverns and seven depleted gas fields. Three of the latter are situated in the west of the country between the Baltic and Wroclaw in the south. Four are clustered in the southeast of country near the Ukrainian border and related gas supply. Four of the sites are relatively small at less than 3 TWh compared to the European average of 9 TWh. One site, Wierzchowice, 15 TWh, accounts for half the country's porous reservoir storage. The conversion capacity is 14 TWh (WGC-90).

5.3.5 Romania

Romania has six operational storage sites, 33 TWh, all depleted gas fields. Three are clustered around the capital, Bucharest, including the largest site, 14 TWh. Two are in the northwestern region, and one in the south, with one planned in the north, 2 TWh. Three of the existing sites have planned extensions, 8 TWh. The potential capacity for hydrogen is 23 TWh (WGC-90).

5.3.6 Serbia

Serbia has one storage site, Banatski Dvor, 5 TWh, a depleted gas field between Belgrade and the Hungary cluster to the north. Two extensions are planned, 5 TWh. The total potential capacity for hydrogen is 5 TWh (WGC-90).

5.3.7 Ukraine

Ukraine has the largest storage capacity in Europe at 339 TWh. The inventory is entirely operational – no planned sites – and consists of two aquifer stores in the north of the country close to the borders with Belarus and Russia, and eleven depleted gas fields: a cluster of five in the northwestern Galicia region, close to the border with Poland; five sites dispersed through the eastern half of the country and one site located near the Black Sea on the Crimean peninsula. The capacity, which is double the porous reservoir average for the three largest EU countries, Italy, Netherlands, and France, at 170 TWh, speaks to its long history of gas production and the two markets it serves in the east and west.

The western cluster contains the largest storage site in Europe, Bilche-Volytsko-Uherske, 179 TWh. The four other sites in the cluster are all larger than 20 TWh, more than twice the European average. As such, the western cluster has an operational capacity of 267 TWh, 79% of the country's total. Combined with the neighbouring depleted gas fields of southeast Poland, this eastern cluster is the second largest in Europe after the central European cluster, and one of four major clusters: Netherlands and northwestern Germany (northwestern Europe), Austria, southern Germany, Czechia, and Slovakia (central Europe), and northern Italy (southern Europe). The relatively dispersed eastern Ukraine cluster is much smaller and centred on Shebelinka. The hydrogen storage potential for Ukraine is 169 TWh (WGC-90).

5.4 Southern Europe

5.4.1 France

France's underground storage inventory is dominated by large aquifer sites. There are 11 operational aquifer stores, 130 TWh, and two closed depleted gas fields, Trois Fontaines l'Abbaye and Soings-en-Sologne, 3 TWh. This unusual inventory reflects a strategic decision to develop much of the storage near Paris and early in the history of natural gas development, before gas fields became sufficiently depleted to be storage candidates. Only one of the storage sites was opened after 1982: Céré-la-Ronde, 1993, which is situated in the west of France. France had access to abundant and low-cost domestic natural gas during the planning and construction phase of their long-lasting aquifer stores, which as strategic national infrastructure, were subsidised by the state. As such, the cushion gas investment was not a commercially prohibitive cost. In this respect, these large aquifer storage sites resemble the large Soviet-era aquifer storage site in Latvia.

Outside of France, a small number of countries have one aquifer site: Latvia, Belgium, Denmark, Spain, and Czechia. Germany has five small aquifer storage sites situated between the salt caverns of the north and large depleted gas field sites of the northwest and southeast. The hydrogen storage capacity of the French aquifer storage sites is 65 TWh (WGC-90).

5.4.2 Greece

Greece has planned a small storage site, South Kavala, 4 TWh, on its northeast coast. The hydrogen storage potential is 2 TWh (WGC-90).

5.4.3 Italy

Italy has 197 TWh of natural gas storage in 13 depleted gas fields, with another 49 TWh planned, also in depleted gas fields. This high storage provision – one of only four countries in the European Union with more than 100 TWh of operational storage in porous reservoirs – when combined with the large number of planned sites, gives Italy the third largest storage capacity for Europe at 246 TWh, after Ukraine, 339 TWh, and Germany, 258 TWh, ahead of the Netherlands, 140 TWh – although these comparable countries are notable for totals that consist of operational assets only with no further planned capacity. The large storage provision reflects demand. Italy is the third largest consumer of natural gas in Europe after Germany and the UK, and the second largest importer after Germany. Storage is clustered close to the upper Po valley industrial hub and high population density of Lombardy. Large storage sites are also strategically located in the northeast to buffer networked gas from the east, and along the Adriatic coast close to land-fall ports for shipped LNG, mostly from Algeria. The conversion capacity for hydrogen is 123 TWh (WGC-90).

5.4.4 Spain

Spain has an annual demand of 360 TWh and imports much of its natural gas, with a roughly equal share between networked gas and LNG. Algeria is the largest network supplier, 110 TWh, via the MEG and MEDGAZ pipelines. France also supplies networked gas, 35 TWh, from the giant gas fields of the Aquitaine basin. The main LNG suppliers are the USA, 60 TWh, Russia, 40 TWh, and Qatar, 30 TWh.

Storage capacity is low at 9% of demand. This is provided by a small number of strategically located storage sites: three depleted gas fields and one aquifer, 34 TWh. The oldest two sites were constructed in the early 1990s: Serrablo, 8 TWh in the Pyrenees, and Gaviota, 11 TWh, 8 km offshore in the Bay of Biscay. Two more sites were added in 2012: Yela, 12 TWh, the only aquifer site, situated close to centre of the gas network, and Marismas, 3 TWh, on the southern Atlantic coast. The potential hydrogen storage capacity is 17 TWh (WGC-90).

5.4.5 Turkey

Turkey has a large, depleted gas field site, Silivri Marmara, 29 TWh, operating since 2010 in the Marmara Sea, near Istanbul. The potential hydrogen capacity is 14 TWh (WGC-90).

This concludes the summary at country level. Outcomes are depicted below – Fig 13.

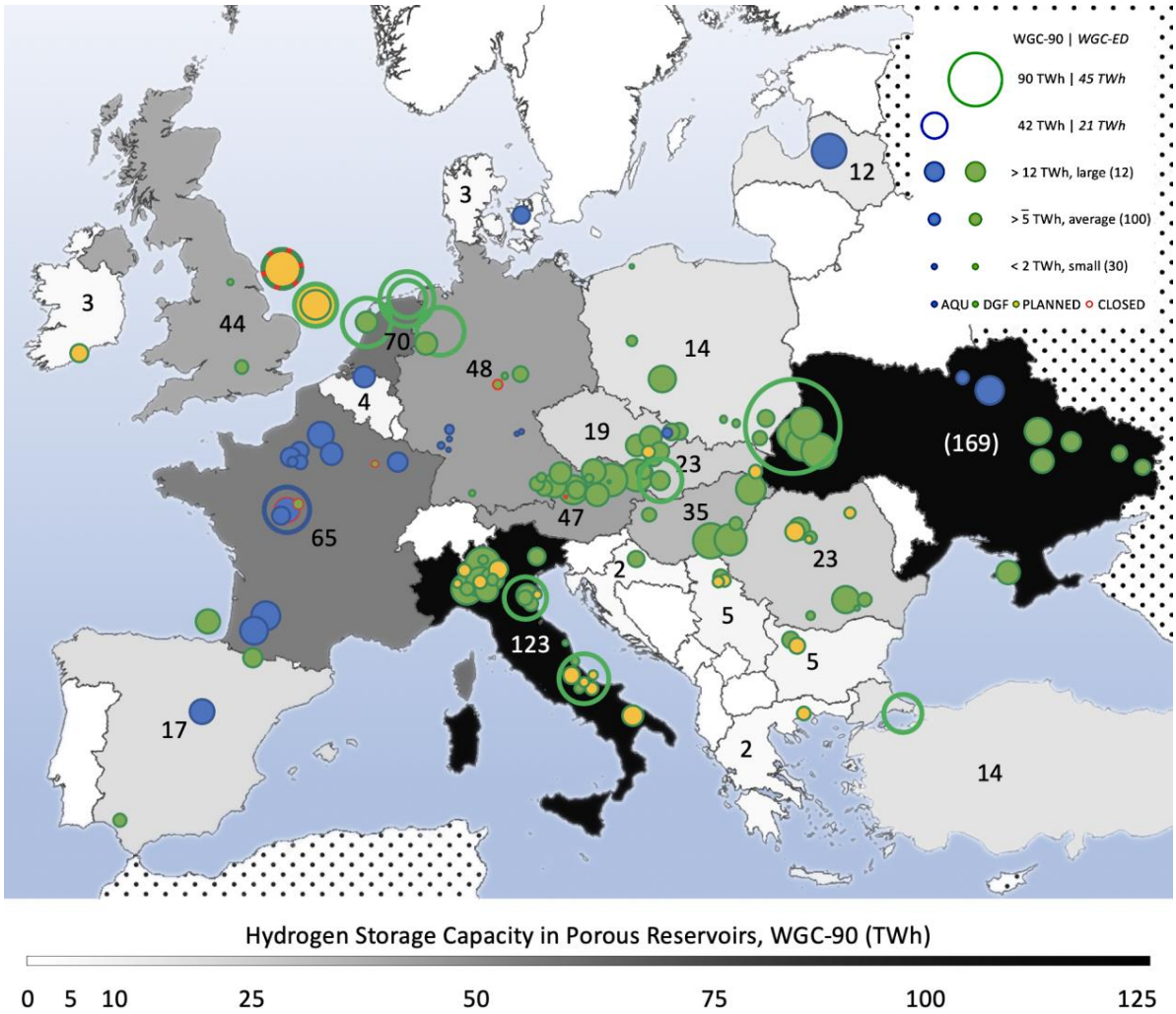


Figure 13. Hydrogen storage capacity for Europe in porous reservoirs for existing and planned gas storage sites.

6. Discussion

This work has identified a long list of existing operational and planned sites that sums to an abundant hydrogen storage resource for Europe, assuming the complete conversion of the existing natural gas storage reserve – Fig 13. The advantage of such an approach is that the existing sites have proven efficacy with respect to gas storage, a networked distribution that reflects the current demand and market, and a deep knowledge base for the operators, regulators, and stakeholders. As such, the Society of Petroleum Engineers' resource frameworks for petroleum systems and CO_2 storage, PRMS and SRMS, would likely classify the 140 operational and planned sites identified in our long list as mature contingencies for hydrogen storage that would qualify as bankable reserves when associated with a final investment decision and development plan of less than five years (SPE 2017, 2018).

The identified storage resource in porous reservoirs sums to 1,500 TWh for natural gas, which converts to a conservative upper limit of 747 TWh for hydrogen (WGC-90) – Fig 14. An alternative heuristic (WGC-ED) provides a conservative lower limit of 373 TWh. Both outcomes indicate a substantial foundation for the envisioned 2050 hydrogen economy given a likely storage requirement of 500 to 1,000 TWh.

The choice of conversion heuristic is crucial to the outcome, differing by a factor of two. The rated capacity heuristic is a radical departure from the common energy density approach. However, it simply reflects the difference between (a) assuming a fixed volume for an energy density conversion and (b) adjusting for hydrogen's flow properties, principally low viscosity, which allow for a much higher rate of withdrawal compared to natural gas under the same pressure conditions. The 90 day-rated heuristic doubles the capacity which implies that the low viscosity and reservoir conditions also allow for the subsurface storage volume to be doubled for the same well count and injection period. It is worth noting that 'conversion' in the context of this report simply refers to replacing stored natural gas with hydrogen. It does not speak to storage blends or technical challenges relating to adapting wells and surface facilities for hydrogen. The next report will go into more detail on justifying the general applicability of WGC-90 and the underlying reservoir engineering formulations, which will be documented as an appendix to both reports.

Regarding gas storage in salt, HyUSPRe, as the acronym implies, focuses on the underground storage available in porous reservoirs, namely depleted gas fields and aquifers. As such, the research does not address salt cavern capacity beyond some general observations and metrics. For example, globally, salt accounts for 8% of natural gas storage, rising to 12% for Europe, reflecting the exceptional resource that is the thick Zechstein salt of the Southern Permian Basin, especially for Germany and northwestern Europe – see Fig 5. This resource will likely remain part of the solution for hydrogen storage. For example, the UK has 38 TWh of salt cavern storage planned (WGC-NG). While beyond the remit of this work, it seems reasonable to assume a 10% contribution from engineered salt caverns to European hydrogen storage if the established share remains proportionate. As such, Europe appears to have approximately 400 to 800 TWh of hydrogen storage potential without recourse to new prospects, aquifer exploration plays, and the vast theoretical resource of depleted gas fields that are not currently associated with storage.

With respect to planned sites and closures, the long list of potential storage sites compiled in this research helps identify two characteristics of the resource base. One of the notable things is how few sites have closed and how, for much of Europe, the planned increase in capacity is quite low. The obvious exception for closures is the UK, which lost much of its capacity with the closure of one large site, the Rough gas storage facility. This was an offshore location that

suffered from well degradation after three decades of service. The technical challenges of the offshore environment are perhaps reflected in the small number of offshore sites. Spain and Turkey are the only other countries with offshore storage, though the UK and Netherlands are considering this option given the sheer number of depleted gas fields in the southern North Sea waters and the expected lower threshold for societal acceptance of offshore storage. The other notable characteristic of the long list is the surprising amount of planned depleted gas field storage for Italy: 16 locations and 49 TWh, which accounts for 60% of the total European planned porous reservoir capacity excluding the UK's ambitious plan to address its long-standing deficiency with respect to gas storage.

With regard to low-to-mid-range demand scenarios, a European hydrogen economy appears to require 250 to 500 TWh of storage capacity. Given the highly mature contingent resource identified in this report, Europe may require a small number of additional storage sites beyond those planned, especially if capacities for hydrogen storage are calculated using energy density alone (WGC-ED). Forecasts of natural gas occupancy in 2050 are highly speculative, with one recent model (Alvik et al., 2022) suggesting 15% repurposing of existing sites for European hydrogen storage, equivalent to 35 TWh (WGC-ED). A low demand scenario would then require at least 40 to 50 additional sites assuming an average capacity of 5 TWh.

A high demand scenario, reflecting an upper estimate of 1,000 TWh of storage - again, using the energy density heuristic and assuming high occupancy with respect to retained natural gas storage out to 2050 - may require an extensive expansion of the existing storage reserve that would potentially double the European portfolio to around 200 sites for hydrogen with an average hydrogen capacity of 5 TWh per site. This report on existing capacity does not address the latter scenario in detail, beyond noting that the forecasts are highly speculative and the identified additional contribution to the long list with respect to pilots, prospects, and targeted expansions, is vanishingly small at approximately 1%, whereas the unprospected theoretical resource is unhelpfully large at tens of thousands of terawatt-hours.

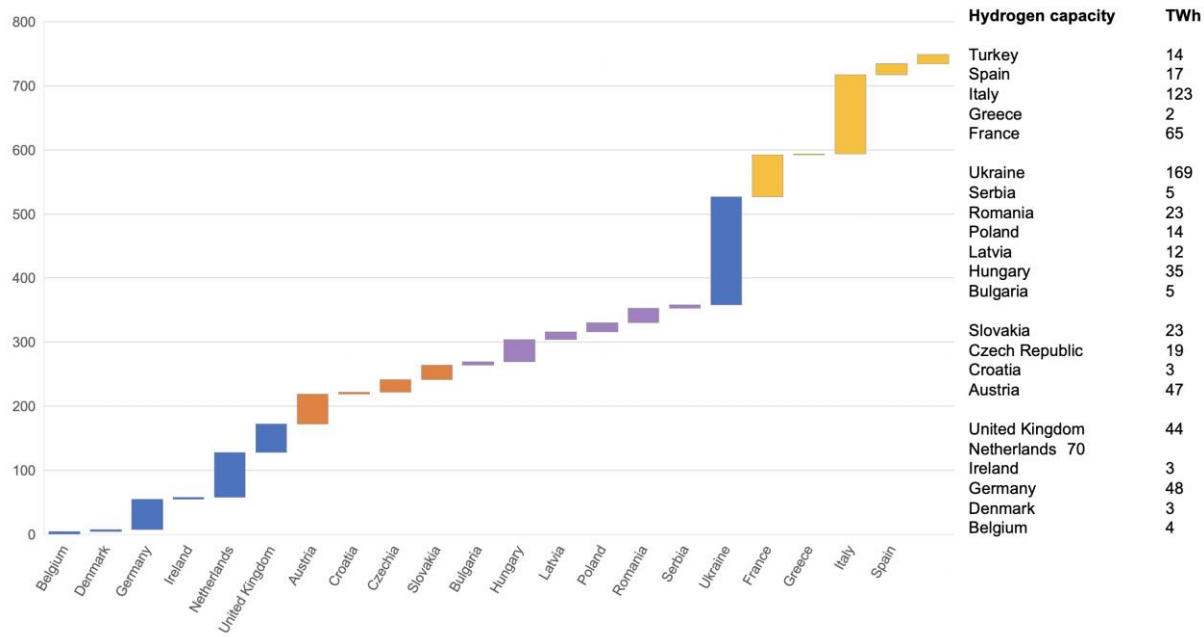


Figure 14. European hydrogen storage capacity in porous reservoirs for existing gas storage by region and country.

One way to view these outcomes is that the extremes reflect the uncertain but rapidly emerging nature of hydrogen storage as a vital element of the energy transition. If natural gas is displaced entirely by hydrogen in all sites (incl. planned), and rated capacity estimates are accurate, the available porous reservoir reserve is substantial at around 750 TWh and likely supplemented by 75 TWh of salt cavern storage. Meeting demand would then require much less exploration and expansion than anticipated by previous reports such as Guidehouse (Cihlar et al, 2021). Whether this complete displacement of natural gas with hydrogen will actually happen, and on what timeframe, is highly uncertain. The timing of the phase-out of natural gas storage versus the ramp-up of hydrogen storage may well result in an imbalance between capacity demand and supply through conversion that would necessitate new sites to be developed.

For an upper-range 1000 TWh estimate, a substantial effort may, in any case, be required to identify new capacity. Much of this might be addressed by simply extending existing sites, or, where possible, adding the next best site within the vicinity. This ‘neighbour’s fence’ analogy would provide a simple doubling of available capacity if each operator is aware of where the nearest most suitable depleted gas field is within the vicinity of an existing site. Where the vicinity criterion fails, expansion will likely extend to suitable prospects closest to demand centres and the existing network. Again, the emphasis here is on the dominant category. Aquifer prospects with no history of gas storage are unlikely to rank highly as additional capacity targets given the considerable financial and technical barriers associated with installing cushion gas and de-risking containment.

Finally, beyond the general disruption, growth, and rapid changes coming to the existing European underground storage network associated with the pivot towards a hydrogen economy, the following countries are noteworthy with respect to degrees of change. Spain is actively seeking to expand its storage capacity after decades of reliance on natural gas imports. This partly reflects the knowledge base and opportunities that are emerging from extensive surveying for underground storage relating to CCS. Spain, like Italy, is also ideally located to develop a green energy economy, both domestically and through imports from North Africa. The UK is in a similar situation, with ambitions to move from a storage deficit to storage abundance in order to support its net zero transition and capitalise on the extraordinary wind energy market that is emerging offshore. The Netherlands has similar resources and is looking to retain and expand its role as an energy balancer for the European gas network. Finally, Ukraine is ideally situated to capitalise on solar energy and will likely retain its role as a network buffer and winter energy supplier in a European hydrogen economy. These countries are likely to join Austria and Germany as early movers in developing additional storage as well as converting existing storage sites in the coming decade.

In summary, the HyUSPRe long list of depleted gas fields and aquifers for hydrogen storage represents the main outcome of this initial report. We have summarised our interpretation of the available data, both with respect to the existing resource, its conversion potential, and a small number of identified additions, as maps and tabulated locations of hydrogen storage locations and capacities. The tabulated values are included in this report as an appendix. The complete long list is archived as an Excel spreadsheet. Where available, this long list of identified sites includes additional metrics for cushion gas, and injection and withdrawal rates. The long list will provide the basis for a short list of candidate sites suitable for detailed analysis in the follow-up report that concludes this analysis.

7. Conclusions

The main indication from our research is that the existing natural gas storage reserve in porous reservoirs is a significant contingent resource. The inventory of operational storage sites, if converted, would provide 664 TWh of hydrogen storage for Europe (WGC-90). Planned sites increase the potential capacity storage to 747 TWh (WGC-90). This is a substantial bankable foundation for the 2050 hydrogen economy, given the known attributes of the existing inventory and its networked status. Current additions to the known reserve of operational and planned storage – pilots, prospects, exploration targets - are relatively small, at most a few percent of the total inventory. The significance of additions will be addressed in more detail in the follow-up report – deliverable D1.5 for this project, March 2023 – that will focus on the selection criteria for a short list of sites and the potential for expanding the hydrogen storage capacity beyond the long list of the existing natural gas storage reserve when converted.

We have noted and avoided the common approach of extremely large theoretical capacity estimates which result from including all potential prospects. Such a low threshold to screening leads to petawatt-hour capacities that exceed even high demand forecasts by orders of magnitude but fails to identify likely candidate sites and locations that conform to the existing network and expected requirement of a European hydrogen economy. The network will likely persist as a backbone, and current demand distributions are well established and indicative of the location and capacity of the future network. The mapped distribution suggests that much of the storage will be onshore and in depleted gas fields, reflecting available resources and the European Union's progression towards networked regional storage and transmission – partly domestic development and partly coordinated action between participating states to balance major hubs and supply corridors. In this first phase of the assessment of hydrogen storage potential we have therefore concentrated on the potential for conversion of the available reserve, which is sufficient for low and mid-range storage scenarios.

Net zero 2050 demand forecasts for hydrogen vary widely, but 2500 TWh appears to be a reasonable mid-range scenario supported by multiple studies. 500 TWh provides 20% storage for the annual demand, which is comparable with the current natural gas storage provision in porous reservoirs across Europe. Reasonable high-and-low demand scenarios could conceivably double or halve the storage requirement to 1000 TWh or 250 TWh.

Under a high-demand scenario, the existing reserve may need to be doubled with an equivalent number of additional sites. A list of 200 to 250 sites has proven difficult to identify given the commercial sensitivity of potential locations close to the existing inventory. However, given the dominance of depleted gas field storage, it is reasonable to assume that a doubling of the inventory will likely result from storage site operators acquiring the next-best depleted gas field closest to their existing sites. A choice of site is unlikely to be made simply on technical grounds. In a second phase of our research and follow-on report, we will address the gap between planned extensions and the additions required to meet a high-demand scenario.

The existing storage available through conversion of operational sites, at 664 TWh, is a good match to a mid-range demand scenario. Planned storage sites increases the potential capacity to 747 TWh. These estimates rely on natural gas storage being entirely displaced in the coming decades in the same way that town gas was displaced by natural gas in the 1970s and 1980s. The estimates also reflect the conversion heuristic applied – a rated capacity for 90 days of withdrawal (WGC-90), which exceeds by a factor of 2 the more commonly assumed energy-density estimate for working gas capacity (WGC-ED). The difference between these approaches has been outlined in detail in the report methodology.

8. Acknowledgement

The analysis has relied on publicly available data, especially the GIE storage database (GIE, 2021) and IGU database (IGU, 2022). GIE, IGU data and other sources are identified in the compiled long list. We are grateful to these organisations for their efforts to communicate detailed technical information transparently.

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Appendix A1 Northwest Europe

HYUSPRE	Country	Code	Site Name	Operator/Developer	Year	Latitude	Longitude	Conv'/Add'	Status	GIE Code	Type	WGC-NG	CUG-NG	WGC/TOG	Source	WGC-ED	WGC-90	INJ-NG	WIR-NG	WHIR-90	HINJ-90
* All capacity metrics are in TWh, all rate metrics are in GWh/day - Values in bold are for hydrogen - Text in red designates closiures, text in purple designates planned sites																					
NORTHWEST EUROPE																					
#HYU111	Belgium	BE	Loenhout	Fluxsys	1985	51.386901	04.702976	Conversion	Operational	BE0101	AQU	9.00	7.91	53%	GIE	2.25	4.50	88	170	85	44
#HYU121	Denmark	DK	Stenlille	Gas Storage Denmark	1994	55.547529	11.623527	Conversion	Operational	DK0102	AQU	5.86	10.84	35%	GIE/IGU	1.46	2.93	47	94	47	23
#HYU131	Germany	DE	Rehden	Astora	1993	52.613427	08.491350	Conversion	Operational	DE0103	DGF	44.51	32.87	58%	GIE	11.13	22.26	345	530	265	172
#HYU132	Germany	DE	Uelsen	Storengy Deutschland	1997	52.505145	06.827938	Conversion	Operational	DE2406	DGF	9.81	8.20	54%	GIE	2.45	4.91	81	108	54	41
#HYU133	Germany	DE	Allmenhausen	TEP	1996	51.219119	10.702006	Conversion	Operational	DE2501	DGF	0.71	3.66	16%	GIE	0.18	0.36	9	17	9	4
#HYU134	Germany	DE	Kirchheiligen	VNG Gasspeicher	1973	51.219029	10.702033	Conversion	Closed	DE3002	DGF	2.02	NAN	NAN	GIE	0.51	1.01	38	34	17	19
#HYU135	Germany	DE	Bad Lauchstädt	VNG Gasspeicher	1975	51.430882	11.833331	Conversion	Operational	DE3005	DGF	5.02	2.62	66%	GIE/IGU	1.25	2.51	55	65	33	27
#HYU136	Germany	DE	Wolfersberg	BayernUGS	1973	48.042520	11.816262	Conversion	Operational	DE0201	DGF	4.12	2.46	63%	GIE	1.03	2.06	38	65	32	19
#HYU137	Germany	DE	Inzenham-West	NAFTA Bavaria GmbH	1982	47.887866	12.102770	Conversion	Operational	DE0401	DGF	4.86	4.67	51%	GIE	1.22	2.43	45	82	41	22
#HYU138	Germany	DE	Fronhofen-Trigonodus	Storengy Deutschland	1997	47.851575	09.415003	Conversion	Operational	DE2402	DGF	0.11	1.57	7%	GIE	0.03	0.06	5	8	4	3
#HYU139	Germany	DE	Bierwang	Uniper Energy Storage	1975	48.127315	12.403860	Conversion	Operational	DE2901	DGF	9.41	12.09	44%	GIE	2.35	4.70	269	349	175	134
#HYU140	Germany	DE	Schmidhausen	Storengy Deutschland	1983	47.915084	12.039386	Conversion	Operational	DE2405	DGF	1.74	1.76	50%	GIE	0.44	0.87	11	40	20	5
#HYU141	Germany	DE	Eschenfelden	Uniper Energy Storage	1976	49.584170	11.630626	Conversion	Operational	DE2905	AQU	0.52	1.25	29%	GIE	0.13	0.26	5	11	5	3
#HYU142	Germany	DE	Frankenthal	Enovos Storage	1979	49.555209	08.409500	Conversion	Operational	DE0801	AQU	0.89	2.07	30%	GIE	0.22	0.44	6	27	13	3
#HYU143	Germany	DE	Hähnlein	MND Gas Storage Germany	1960	49.744230	08.552879	Conversion	Operational	DE1701	AQU	0.90	0.90	50%	GIE/IGU	0.23	0.45	17	27	14	8
#HYU144	Germany	DE	Stockstadt	MND Gas Storage Germany	1969	49.747913	08.604075	Conversion	Operational	DE1702	AQU	1.53	1.57	49%	GIE/IGU	0.38	0.76	25	37	19	12
#HYU145	Germany	DE	Eschenfelden	N-ERGIE	1976	49.584170	11.630626	Conversion	Operational	DE1801	AQU	0.23	NAN	NAN	GIE	0.06	0.11	52	163	81	26
#HYU146	Germany	DE	Sandhausen	Terranets bw	1991	49.327346	08.644799	Conversion	Operational	DE2601	AQU	0.35	0.44	44%	GIE	0.09	0.17	6	12	6	3
#HYU147	Germany	DE	Breitbrunn	Uniper Energy Storage	1996	47.918588	12.413868	Conversion	Operational	DE2902	DGF	11.22	11.27	50%	GIE	2.81	5.61	67	140	70	34
#HYU151	Ireland	IE	Kinsale Head	dCarbonX	2025	51.805460	-08.179480	Addition	Planned	NAN	DGF	6.00	NAN	NAN	dCarbonX	1.50	3.00	NAN	NAN	NAN	NAN
#HYU161	Netherlands	NL	Grijpskerk	NAM	1997	53.277349	06.315630	Conversion	Operational	NL0201	DGF	27.67	126.16	18%	GIE	6.92	13.83	173	719	360	86
#HYU162	Netherlands	NL	Norg Langelo	NAM	1997	53.090908	06.429978	Conversion	Operational	NL0202	DGF	59.34	220.54	21%	GIE	14.83	29.67	449	791	396	224
#HYU163	Netherlands	NL	Bergermeer	TAQA	2015	52.650955	04.717011	Conversion	Operational	NL0301	DGF	48.15	50.50	49%	GIE	12.04	24.08	408	491	245	204
#HYU164	Netherlands	NL	Alkmaar	TAQA	1997	52.656262	04.743204	Conversion	Operational	NL0302	DGF	4.90	30.38	14%	GIE	1.23	2.45	36	353	176	18
#HYU171	UK	GB	Humbly Grove	Humbly Grove Energy	2005	51.195193	-01.010065	Conversion	Operational	GB0501	DGF	3.42	NAN	NAN	GIE	0.86	1.71	27	38	19	13
#HYU172	UK	GB	Hatfield Moor	Scottish Power	2000	53.553731	-00.958480	Conversion	Operational	GB0901	DGF	0.80	NAN	NAN	GIE	0.20	0.40	6	9	4	3
#HYU173	UK	GB	Rough	Centrica	1985	53.656666	00.116225	Conversion	Closed	NAN	DGF	30.20	NAN	NAN	Amid	7.55	15.10	235	336	168	117
#HYU174	UK	GB	Baird	Centrica	2025	53.554118	-00.958393	Addition	Planned	NAN	DGF	18.00	NAN	NAN	Centrica	4.50	9.00	140	200	100	70
#HYU175	UK	GB	Deborah	UK Gov	2025	53.845410	00.366570	Addition	Planned	NAN	DGF	36.00	NAN	NAN	UK Gov	9.00	18.00	280	400	200	140

Key: Aquifers Depleted gas fields Operational sites (black text) Closed sites (red text) Planned sites (purple text)

Appendix A2 Central Europe

HYUSPRE	Country	Code	Site Name	Operator/Developer	Year	Latitude	Longitude	Conv'/Add'	Status	GIE Code	Type	WGC-NG	CUG-NG	WGC/TOG	Source	WGC-ED	WGC-90	INJ-NG	WIR-NG	WHIR-90	HINJ-90
* All capacity metrics are in TWh, all rate metrics are in GWh/day - Values in bold are for hydrogen - Text in red designates closiures, text in purple designates planned sites																					
CENTRAL EUROPE																					
#HYU211	Austria	AT	Haidach	Astora	2007	47.986580	13.230318	Conversion	Operational	AT0101	DGF	11.03	4.45	71%	GIE	2.76	5.52	99	105	52	50
#HYU212	Austria	AT	Haidach	GSA	2007	47.986580	13.230318	Conversion	Operational	AT0201	DGF	21.32	8.49	72%	GIE	5.33	10.66	185	209	104	92
#HYU213	Austria	AT	Schönkirchen Reyersdorf	OMV Gas Storage	1977	48.355086	16.698936	Conversion	Operational	AT0301	DGF	20.72	20.34	50%	GIE	5.18	10.36	176	260	130	88
#HYU214	Austria	AT	Tallesbrunn	OMV Gas Storage	1974	48.355164	16.777897	Conversion	Operational	AT0302	DGF	4.52	3.16	59%	GIE	1.13	2.26	34	43	22	17
#HYU215	Austria	AT	Aigelsbrunn	RAG Energy Storage	2011	47.995010	13.307772	Conversion	Operational	AT0401	DGF	1.50	0.28	84%	GIE	0.38	0.75	14	14	7	7
#HYU216	Austria	AT	Haidach 5	RAG Energy Storage	2006	47.983239	13.240435	Conversion	Operational	AT0402	DGF	0.18	0.18	50%	GIE	0.05	0.09	5	5	3	3
#HYU217	Austria	AT	Nussdorf Zagling	RAG Energy Storage	2014	47.966144	13.357581	Conversion	Operational	AT0403	DGF	6.20	NAN	NAN	GIE	1.55	3.10	41	62	31	20
#HYU218	Austria	AT	Puchkirchen Haag	RAG Energy Storage	1982	48.015971	13.573512	Conversion	Operational	AT0404	DGF	12.20	5.74	68%	GIE	3.05	6.10	142	142	71	71
#HYU219	Austria	AT	7 Fields	Uniper Energy Storage	2011	48.078665	13.136385	Conversion	Operational	AT0501	DGF	17.51	NAN	NAN	GIE	4.38	8.76	146	219	109	73
#HYU220	Austria	AT	Vöcklabruck	Underground Sun Storage	2016	48.035249	13.704796	Addition	Pilot	NAN	DGF	0.02	NAN	NAN	RAG	0.01	0.01	NAN	NAN	NAN	NAN
#HYU231	Croatia	HR	Okoli	PSP	1988	45.586568	16.523645	Conversion	Operational	HR0101	DGF	5.22	NAN	NAN	GIE	1.31	2.61	42	56	28	21
#HYU332	Croatia	HR	Grubisno Polje	PSP	2022	45.714131	17.139709	Conversion	Planned	HR0102	DGF	0.29	NAN	NAN	GIE	0.07	0.15	16	27	14	8
#HYU241	Czech Republic	CZ	Dolni Dunajovice	RWE Gas Storage	1989	48.859525	16.604578	Conversion	Operational	CZ0101	DGF	9.59	9.39	51%	GIE/IGU	2.40	4.79	128	227	113	64
#HYU242	Czech Republic	CZ	Lobodice	RWE Gas Storage	1965	49.401531	17.298534	Conversion	Operational	CZ0103	AQU	1.89	1.68	53%	GIE/IGU	0.47	0.94	32	53	27	16
#HYU243	Czech Republic	CZ	Štramberk	RWE Gas Storage	1983	49.593466	18.091240	Conversion	Operational	CZ0104	DGF	5.33	4.03	57%	GIE/IGU	1.33	2.66	75	75	37	37
#HYU244	Czech Republic	CZ	Třanovice	RWE Gas Storage	2000	49.714505	18.532454	Conversion	Operational	CZ0105	DGF	5.64	3.51	62%	GIE/IGU	1.41	2.82	69	85	43	35
#HYU245	Czech Republic	CZ	Tvrdonice	RWE Gas Storage	1975	48.769846	16.969569	Conversion	Operational	CZ0106	DGF	5.59	5.02	53%	GIE/IGU	1.40	2.80	91	85	43	45
#HYU246	Czech Republic	CZ	Uhřice	MND Gas Storage	2001	49.041384	16.935813	Conversion	Operational	CZ0201	DGF	3.19	3.00	52%	GIE	0.80	1.60	58	107	54	29
#HYU247	Czech Republic	CZ	Uhřice	MND Gas Storage	2025	49.041384	16.935813	Conversion	Planned	CZ0201	DGF	0.43	NAN	NAN	GIE	0.11	0.22	58	107	54	29
#HYU248	Czech Republic	CZ	Dolni Bojanovice	SPP Storage	1999	48.871558	17.028362	Conversion	Operational	CZ0401	DGF	6.94	NAN	NAN	GIE	1.74	3.47	74	96	48	37
#HYU251	Slovakia	SK	Láb Complex	Nafta	1997	48.379868	16.983331	Conversion	Operational	SK0101	DGF	36.50	NAN	NAN	GIE	9.13	18.25	338	419	209	169
#HYU252	Slovakia	SK	Velke Kapusany	Nafta	NAN	48.531363	22.070405	Conversion	Planned	SK0103	DGF	3.61	NAN	NAN	GIE	0.90	1.80	40	40	20	20
#HYU253	Slovakia	SK	Láb 4	Pozagas	1997	48.452443	17.009440	Conversion	Operational	SK0201	DGF	6.95	10.90	39%	GIE	1.74	3.47	73	73	36	36

Key: Aquifers Depleted gas fields Operational sites (black text) Closed sites (red text) Planned sites (purple text)

Appendix A3 Eastern Europe

HYUSPRE	Country	Code	Site Name	Operator/Developer	Year	Latitude	Longitude	Conv'/Add'	Status	GIE Code	Type	WGC-NG	CUG-NG	WGC/TOG	Source	WGC-ED	WGC-90	INJ-NG	WIR-NG	WHIR-90	HINJ-90
* All capacity metrics are in TWh, all rate metrics are in GWh/day - Values in bold are for hydrogen - Text in red designates closiures, text in purple designates planned sites																					
EASTERN EUROPE																					
#HYU301	Bulgaria	BG	Chiren	Bulgartransgaz	1974	43.349912	23.591861	Conversion	Operational	BG0101	DGF	5.80	7.91	42%	GIE	1.45	2.90	38	40	20	19
#HYU302	Bulgaria	BG	Chiren	Bulgartransgaz	2026	43.349912	23.591861	Conversion	Planned	BG0102	DGF	4.75	NAN	NAN	GIE	1.19	2.38	46	44	22	23
#HYU311	Hungary	HU	Hajdúszoboszló	Hungarian Gas Storage	1981	47.508376	21.369442	Conversion	Operational	HU0101	DGF	18.33	26.93	41%	GIE	4.58	9.17	113	185	93	56
#HYU312	Hungary	HU	Kardoskút	Hungarian Gas Storage	1978	46.496213	20.717672	Conversion	Operational	HU0102	DGF	3.13	2.91	52%	GIE	0.78	1.56	18	34	17	9
#HYU313	Hungary	HU	Pusztaederics	Hungarian Gas Storage	1979	46.656743	16.794541	Conversion	Operational	HU0103	DGF	3.80	2.97	56%	GIE	0.95	1.90	33	34	17	16
#HYU314	Hungary	HU	Zsana	Hungarian Gas Storage	1996	46.544758	19.679896	Conversion	Operational	HU0104	DGF	24.26	16.05	60%	GIE	6.06	12.13	191	324	162	95
#HYU315	Hungary	HU	Szöreg-1	Hexum	2009	46.301600	20.188412	Conversion	Operational	HU0201	DGF	20.11	NAN	NAN	GIE	5.03	10.06	134	264	132	67
#HYU321	Latvia	LV	Inčukalns	Conexus Baltic Grid	1968	57.168333	24.695446	Conversion	Operational	LV0101	AQU	24.20	22.57	52%	GIE	6.05	12.10	179	316	158	89
#HYU331	Poland	PL	Wierzchowice	Gas Storage Poland	1995	51.475274	17.306656	Conversion	Operational	PL0101	DGF	14.73	NAN	NAN	GIE	3.68	7.37	108	158	79	54
#HYU332	Poland	PL	Swarzow	Gas Storage Poland	1979	50.197296	20.945515	Conversion	Operational	PL0106	DGF	1.01	1.25	45%	GIE	0.25	0.51	11	10	5	6
#HYU333	Poland	PL	Brzeznica	Gas Storage Poland	1979	50.091529	21.485691	Conversion	Operational	PL0107	DGF	1.13	0.87	56%	GIE	0.28	0.56	16	16	8	8
#HYU334	Poland	PL	Strachocina	Gas Storage Poland	1982	49.626458	22.071696	Conversion	Operational	PL0108	DGF	4.08	6.02	40%	GIE	1.02	2.04	30	38	19	15
#HYU335	Poland	PL	Husow	Gas Storage Poland	1987	50.007104	22.263525	Conversion	Operational	PL0109	DGF	5.65	6.22	48%	GIE	1.41	2.83	47	65	32	23
#HYU336	Poland	PL	Bonikowo	PGNiG	2010	52.114339	16.554157	Conversion	Operational	PL0301	DGF	2.30	3.77	38%	GIE	0.58	1.15	19	28	14	10
#HYU337	Poland	PL	Daszewo	PGNiG	2009	54.059374	15.929912	Conversion	Operational	PL0302	DGF	0.35	0.32	52%	GIE	0.09	0.17	3	4	2	1
#HYU341	Romania	RO	Balanceanca	Depogaz Ploieşti	1992	44.377703	26.263444	Conversion	Operational	RO0101	DGF	0.55	0.44	56%	GIE	0.14	0.27	11	13	7	5
#HYU342	Romania	RO	Bilciuresti	Depogaz Ploieşti	1983	44.690617	25.783644	Conversion	Operational	RO0102	DGF	14.21	6.86	67%	GIE	3.55	7.11	109	152	76	54
#HYU343	Romania	RO	Ghercesti	Depogaz Ploieşti	2004	44.362433	23.872108	Conversion	Operational	RO0104	DGF	1.60	NAN	NAN	GIE	0.40	0.80	21	21	11	11
#HYU344	Romania	RO	Moldova (Falticeni)	Depogaz Ploieşti	2023	47.461807	26.303339	Conversion	Planned	RO0105	DGF	2.16	NAN	NAN	GIE	0.54	1.08	15	22	11	8
#HYU345	Romania	RO	Sarmasel	Depogaz Ploieşti	1995	46.783333	24.184831	Conversion	Operational	RO0106	DGF	9.52	18.62	34%	GIE	2.38	4.76	69	79	40	34
#HYU346	Romania	RO	Sarmasel	Depogaz Ploieşti	2024	46.783333	24.184831	Conversion	Planned	RO0107	DGF	7.22	NAN	NAN	GIE	1.80	3.61	39	29	14	20
#HYU347	Romania	RO	Urziceni	Depogaz Ploieşti	1979	44.718363	26.610866	Conversion	Operational	RO0108	DGF	3.95	9.09	30%	GIE	0.99	1.98	33	49	25	16
#HYU348	Romania	RO	Târgu Mureş	Depomures	2002	46.514308	24.606278	Conversion	Operational	RO0201	DGF	3.15	22.26	12%	GIE	0.79	1.58	19	28	14	10
#HYU349	Romania	RO	Târgu Mureş	Depomures	2023	46.514308	24.606278	Conversion	Planned	RO0202	DGF	1.05	NAN	NAN	GIE	0.26	0.53	19	19	9	9
#HYU350	Romania	RO	Târgu Mureş	Depomures	2026	46.514308	24.606278	Conversion	Planned	RO0203	DGF	2.10	NAN	NAN	GIE	0.53	1.05	16	16	8	8
#HYU361	Serbia	RS	Banatski Dvor	Srbijagas	2011	45.537206	20.474084	Conversion	Operational	RS0101	DGF	4.53	NAN	NAN	GIE	1.13	2.27	35	50	25	18
#HYU362	Serbia	RS	Banatski Dvor	Srbijagas	NAN	45.537206	20.474084	Conversion	Planned	RS0102	DGF	3.02	NAN	NAN	GIE/IGU	0.76	1.51	23	34	17	12
#HYU363	Serbia	RS	Banatski Dvor	Srbijagas	NAN	45.537206	20.474084	Conversion	Planned	RS0103	DGF	2.52	NAN	NAN	GIE/IGU	0.63	1.26	20	28	14	10
#HYU381	Ukraine	UA	Hlibovske	PJSC Chomomomaftogaz	1987	45.506170	33.014712	Conversion	Operational	UA0201	DGF	11.00	NAN	NAN	IGU	2.75	5.50	44	50	25	22
#HYU382	Ukraine	UA	Bilche-Volytsko-Uherske	PJSC Ukrtransgaz	1990	49.360367	23.905826	Conversion	Operational	UA0101	DGF	179.70	1728.49	9%	IGU	44.93	89.85	1075	1265	633	538
#HYU383	Ukraine	UA	Bohorodchanske	PJSC Ukrtransgaz	1979	48.816799	24.497500	Conversion	Operational	UA0102	DGF	24.40	11.88	67%	IGU	6.10	12.20	529	275	138	96
#HYU384	Ukraine	UA	Chervonopartyzanske	PJSC Ukrtransgaz	1989	51.052406	31.620303	Conversion	Operational	UA0103	AQU	16.00	16.00	50%	IGU	4.00	8.00	171	110	55	38
#HYU385	Ukraine	UA	Dashavske	PJSC Ukrtransgaz	1987	49.285497	24.026036	Conversion	Operational	UA0104	DGF	22.90	35.31	39%	IGU	5.73	11.45	277	277	138	97
#HYU386	Ukraine	UA	Kehychivske	PJSC Ukrtransgaz	1988	49.340248	35.820513	Conversion	Operational	UA0105	DGF	7.40	6.34	54%	IGU	1.85	3.70	95	90	45	31
#HYU387	Ukraine	UA	Krasnopopivske	PJSC Ukrtransgaz	1977	49.106585	38.163335	Conversion	Operational	UA0106	DGF	4.50	4.07	53%	GIE	1.13	2.25	53	53	27	19
#HYU388	Ukraine	UA	Olyshivske	PJSC Ukrtransgaz	1978	51.203893	31.290445	Conversion	Operational	UA0107	AQU	3.30	3.73	47%	IGU	0.83	1.65	22	21	11	7
#HYU389	Ukraine	UA	Oparske	PJSC Ukrtransgaz	1984	49.393442	23.705153	Conversion	Operational	UA0108	DGF	20.30	28.02	42%	IGU	5.08	10.15	222	222	111	78
#HYU390	Ukraine	UA	Proletarske	PJSC Ukrtransgaz	1991	49.001878	35.154723	Conversion	Operational	UA0109	DGF	10.80	10.80	50%	IGU	2.70	5.40	108	108	54	38
#HYU391	Ukraine	UA	Solokhivske	PJSC Ukrtransgaz	1987	49.927201	34.505704	Conversion	Operational	UA0110	DGF	13.80	8.49	62%	IGU	3.45	6.90	138	84	42	29
#HYU392	Ukraine	UA	Uherske (XIV-XV)	PJSC Ukrtransgaz	1982	49.316317	23.913392	Conversion	Operational	UA0111	DGF	20.10	20.63	49%	IGU	5.03	10.05	243	243	121	85
#HYU393	Ukraine	UA	Verhunske	PJSC Ukrtransgaz	1996	48.621057	39.327431	Conversion	Operational	UA0112	DGF	4.56	6.28	42%	IGU	1.14	2.28	35	51	25	18

Key: Aquifers Depleted gas fields Operational sites (black text) Closed sites (red text) Planned sites (purple text)

Appendix A4 Southern Europe Part A

HYUSPRE	Country	Code	Site Name	Operator/Developer	Year	Latitude	Longitude	Conv'/Add'	Status	GIE Code	Type	WGC-NG	CUG-NG	WGC/TOG	Source	WGC-ED	WGC-90	INJ-NG	WIR-NG	WHIR-90	HINJ-90
* All capacity metrics are in TWh, all rate metrics are in GWh/day - Values in bold are for hydrogen - Text in red designates closiures, text in purple designates planned sites																					
SOUTHERN EUROPE																					
#HYU411	France	FR	Beynes Profond	Storengy	1956	48.845097	01.876452	Conversion	Operational	FR0104	AQU	3.76	NAN	NAN	IGU	0.94	1.88	47	96	48	23
#HYU412	France	FR	Beynes Supérieur	Storengy	1956	48.845097	01.876452	Conversion	Operational	FR0105	AQU	1.94	NAN	NAN	IGU	0.48	0.97	27	49	25	14
#HYU413	France	FR	Saint-Illiers-la-Ville	Storengy	1965	48.985623	01.551293	Conversion	Operational	FR0106	AQU	7.75	12.07	39%	IGU	1.94	3.88	131	164	82	66
#HYU414	France	FR	Gournay-sur-Aronde	Storengy	1976	49.529132	02.703032	Conversion	Operational	FR0107	AQU	13.40	19.84	40%	GIE	3.35	6.70	100	223	112	50
#HYU415	France	FR	Cerville	Storengy	1970	48.702654	06.296046	Conversion	Operational	FR0108	AQU	7.41	9.69	43%	IGU	1.85	3.71	90	104	52	45
#HYU416	France	FR	Germigny-sous-Coulombs	Storengy	1982	00.000000	00.000000	Conversion	Operational	FR0109	AQU	9.35	21.32	30%	IGU	2.34	4.67	52	90	45	26
#HYU417	France	FR	Saint-Clair-sur-Epte	Storengy	1982	49.203228	01.706278	Conversion	Operational	FR0110	AQU	6.04	6.56	48%	IGU	1.51	3.02	33	41	21	16
#HYU418	France	FR	Trois Fontaines l'Abbaye	Storengy	1970	48.699835	04.973056	Conversion	Closed	FR0111	DGF	0.91	NAN	NAN	IGU	0.23	0.46	5	5	3	3
#HYU419	France	FR	Serene Sud	Storengy	NAN	47.426660	01.499039	Conversion	Closed	FR0100	AQU	12.90	NAN	NAN	GIE	3.23	6.45	91	145	73	46
#HYU420	France	FR	Céré-la-Ronde	Storengy	1993	47.282749	01.218462	Conversion	Operational	FR0112	AQU	6.50	6.61	50%	IGU	1.62	3.25	112	107	53	56
#HYU421	France	FR	Chémery	Storengy	1968	47.389974	01.484223	Conversion	Operational	FR0113	AQU	42.29	39.90	51%	IGU	10.57	21.15	200	432	216	100
#HYU422	France	FR	Soings-en-Sologne	Storengy	1970	47.426660	01.499039	Conversion	Closed	FR0114	DGF	2.39	6.61	27%	IGU	0.60	1.20	16	16	8	8
#HYU423	France	FR	Izaute	Terega	1981	43.790813	-00.110062	Conversion	Operational	FR0201	AQU	16.59	17.61	49%	IGU	4.15	8.29	192	150	75	96
#HYU424	France	FR	Lussagnet	Terega	1957	43.780050	-00.220088	Conversion	Operational	FR0202	AQU	15.31	17.18	47%	IGU	3.83	7.66	246	274	137	123
#HYU431	Greece	GR	South Kavala	HRADF	2022	40.959225	24.543739	Conversion	Planned	GR0101	DGF	3.86	1.36	74%	GIE	0.97	1.93	55	44	22	28

Key: Aquifers Depleted gas fields Operational sites (black text) Closed sites (red text) Planned sites (purple text)

Appendix A4 Southern Europe Part B

HYUSPRE	Country	Code	Site Name	Operator/Developer	Year	Latitude	Longitude	Conv'/Add'	Status	GIE Code	Type	WGC-NG	CUG-NG	WGC/TOG	Source	WGC-ED	WGC-90	INJ-NG	WIR-NG	WHIR-90	HINJ-90
* All capacity metrics are in TWh, all rate metrics are in GWh/day - Values in bold are for hydrogen - Text in red designates closiures, text in purple designates planned sites																					
SOUTHERN EUROPE																					
#HYU445	Italy	IT	San Benedetto	Gas Plus Storage	NAN	42.925672	13.874446	Conversion	Planned	IT0201	DGF	5.74	NAN	NAN	GIE	1.44	2.87	65	65	33	33
#HYU446	Italy	IT	Poggiofiorito	Gas Plus Storage	NAN	42.245020	14.224626	Conversion	Planned	IT0202	DGF	1.83	NAN	NAN	GIE	0.46	0.91	19	19	9	9
#HYU447	Italy	IT	Sinarca	Gas Plus Storage	NAN	41.923567	14.825188	Conversion	Planned	IT0203	DGF	3.56	NAN	NAN	GIE	0.89	1.78	35	35	18	18
#HYU448	Italy	IT	Cugno le Macine	Geogastock	NAN	40.579584	16.358448	Conversion	Planned	IT0301	DGF	8.80	NAN	NAN	GIE	2.20	4.40	110	110	55	55
#HYU449	Italy	IT	Cornegliano	Ital Gas Storage	2018	45.295078	09.501809	Conversion	Operational	IT0401	DGF	1.58	NAN	NAN	GIE	0.40	0.79	15	22	11	8
#HYU450	Italy	IT	Alfonsine	STOGIT	2026	44.532478	11.986352	Conversion	Planned	IT0510	DGF	1.55	2.08	43%	GIE	0.39	0.78	26	26	13	13
#HYU451	Italy	IT	Bordolano	STOGIT	NAN	45.285330	09.975683	Conversion	Planned	IT0511	DGF	2.58	NAN	NAN	GIE	0.65	1.29	14	21	10	7
#HYU452	Italy	IT	Fiume Treste	STOGIT	2021	42.022898	14.701111	Conversion	Planned	IT0512	DGF	2.07	NAN	NAN	GIE/IGU	0.52	1.03	29	41	21	14
#HYU453	Italy	IT	Fiume Treste F	STOGIT	2021	42.022898	14.701111	Conversion	Planned	IT0513	DGF	2.07	NAN	NAN	GIE/IGU	0.52	1.03	16	23	11	8
#HYU454	Italy	IT	Minerbio	STOGIT	NAN	44.607888	11.500503	Conversion	Planned	IT0514	DGF	4.35	NAN	NAN	GIE/IGU	1.09	2.17	34	48	24	17
#HYU455	Italy	IT	Ripalta	STOGIT	NAN	45.312344	09.700626	Conversion	Planned	IT0515	DGF	0.00	NAN	NAN	IGU	0.00	0.00	21	NAN	NAN	10
#HYU456	Italy	IT	Ripalta	STOGIT	2026	45.312344	09.700626	Conversion	Planned	IT0516	DGF	3.72	245.74	1%	GIE/IGU	0.93	1.86	29	41	21	14
#HYU457	Italy	IT	Sabbioncello	STOGIT	2023	44.798786	11.900991	Conversion	Planned	IT0517	DGF	0.00	NAN	NAN	IGU	0.00	0.00	43	62	31	22
#HYU458	Italy	IT	Sergnano	STOGIT	NAN	45.428076	09.688561	Conversion	Planned	IT0518	DGF	1.66	NAN	NAN	GIE/IGU	0.41	0.83	13	18	9	6
#HYU459	Italy	IT	Settala	STOGIT	2026	45.451020	09.403092	Conversion	Planned	IT0519	DGF	3.62	NAN	NAN	IGU	0.90	1.81	28	40	20	14
#HYU460	Italy	IT	Bordolano	STOGIT	2016	45.285330	09.975683	Conversion	Operational	IT0501	DGF	11.34	6.11	65%	IGU	2.84	5.67	162	216	108	81
#HYU461	Italy	IT	Brugherio	STOGIT	1966	45.541709	09.251643	Conversion	Operational	IT0502	DGF	3.57	6.54	35%	IGU	0.89	1.78	65	86	43	32
#HYU462	Italy	IT	Cortemaggiore	STOGIT	1964	44.999729	09.958592	Conversion	Operational	IT0503	DGF	10.37	18.94	35%	IGU	2.59	5.19	162	119	59	81
#HYU463	Italy	IT	Fiume Treste	STOGIT	1982	42.022898	14.701111	Conversion	Operational	IT0504	DGF	50.26	41.82	55%	IGU	12.57	25.13	324	519	259	162
#HYU464	Italy	IT	Minerbio	STOGIT	1975	44.607888	11.500503	Conversion	Operational	IT0505	DGF	35.81	22.04	62%	IGU	8.95	17.90	238	492	246	119
#HYU465	Italy	IT	Ripalta	STOGIT	1967	45.312344	09.700626	Conversion	Operational	IT0506	DGF	18.22	14.35	56%	IGU	4.55	9.11	205	227	113	103
#HYU466	Italy	IT	Sabbioncello	STOGIT	1985	44.798786	11.900991	Conversion	Operational	IT0507	DGF	9.45	6.30	60%	IGU	2.36	4.73	108	178	89	54
#HYU467	Italy	IT	Sergnano	STOGIT	1965	45.428076	09.688561	Conversion	Operational	IT0508	DGF	24.25	15.30	61%	IGU	6.06	12.12	216	486	243	108
#HYU468	Italy	IT	Settala	STOGIT	1986	45.451020	09.403092	Conversion	Operational	IT0509	DGF	19.68	32.60	38%	IGU	4.92	9.84	108	357	178	54
#HYU469	Italy	IT	Bagnolo Mella	GDF Suez Italy	NAN	45.417400	10.143689	Conversion	Planned	IT0601	DGF	7.22	NAN	NAN	IGU	1.81	3.61	56	80	40	28
#HYU471	Spain	ES	Gaviota	Enagas	1993	43.442906	-02.756391	Conversion	Operational	ES0101	DGF	11.17	19.39	37%	GIE/IGU	2.79	5.59	51	65	32	23
#HYU472	Spain	ES	Marismas	Gas Natural Fenosa	2012	37.143828	-06.527869	Conversion	Operational	ES0102	DGF	3.42	3.42	50%	GIE/IGU	0.86	1.71	47	47	23	16
#HYU473	Spain	ES	Serrablo	Enagas	1991	42.549194	-00.396969	Conversion	Operational	ES0103	DGF	7.75	4.79	62%	GIE/IGU	1.94	3.88	43	76	38	27
#HYU474	Spain	ES	Yela	Enagas	2012	40.836007	-02.783190	Conversion	Operational	ES0104	AQU	11.97	10.26	54%	GIE/IGU	2.99	5.99	114	171	86	60
#HYU482	Turkey	TR	Silivri Marmara	Turkish Petroleum	2010	41.106266	28.180947	Conversion	Operational	TR0302	DGF	28.75	NAN	NAN	GIE/IGU	7.19	14.38	224	319	160	112
#HYU483	Turkey	TR	Silivri Marmara	Turkish Petroleum	NAN	41.106266	28.180947	Conversion	Planned	TR0303	DGF	16.15	NAN	NAN	GIE/IGU	0.00	0.00	224	521	0	0

Key: Aquifers Depleted gas fields Operational sites (black text) Closed sites (red text) Planned sites (purple text)