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Underground storage for decarbonisation: Trade-offs between hydrogen, natural gas, and carbon dioxide

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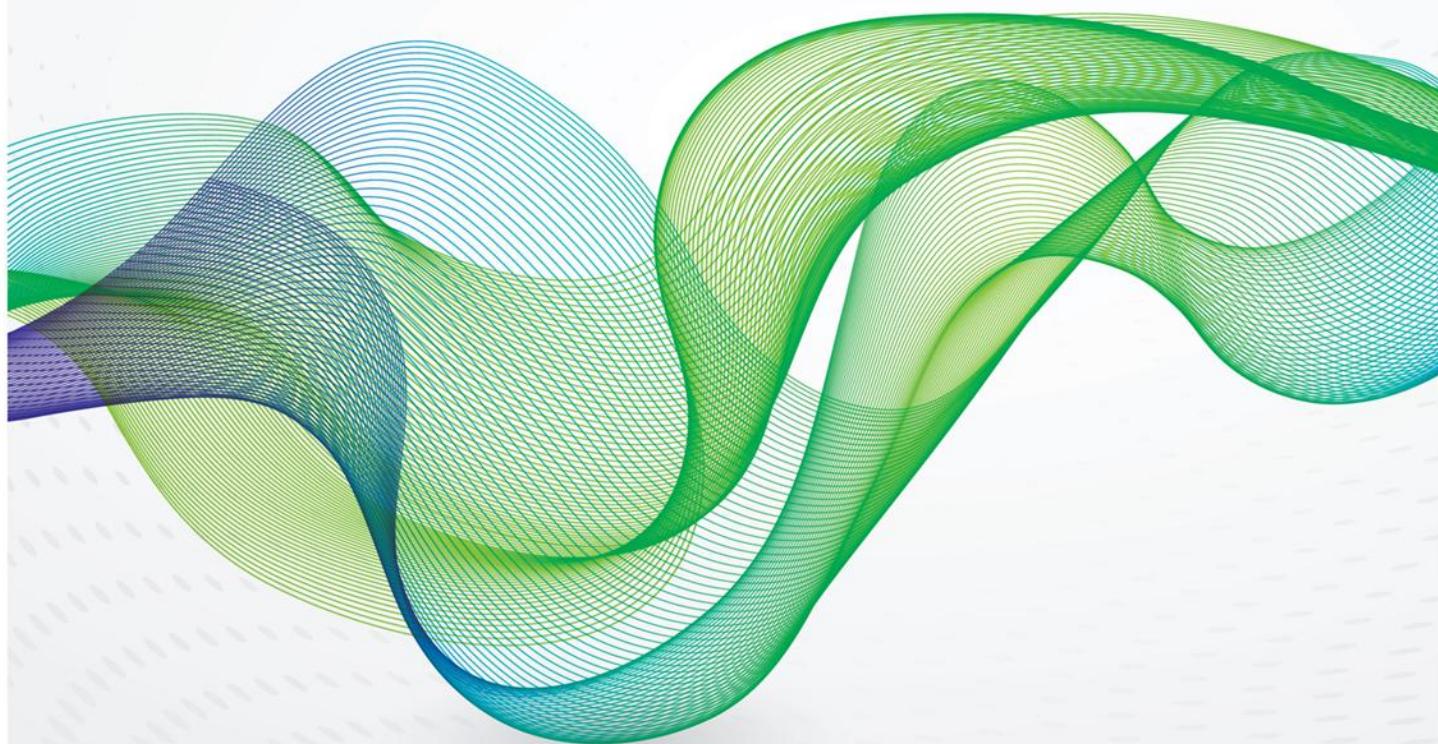
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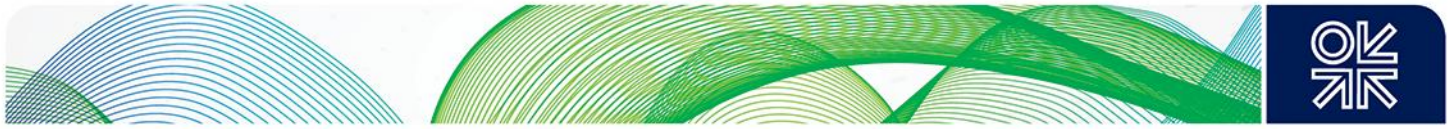
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June 2025

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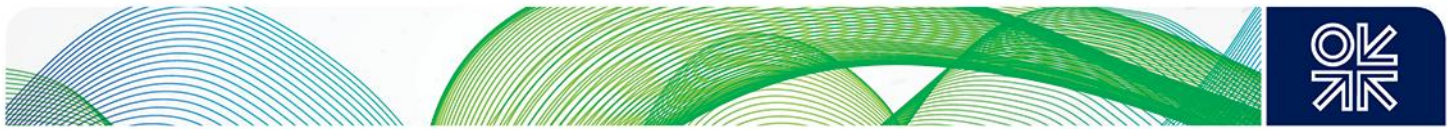
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Abstract

As decarbonisation efforts accelerate globally, the role of large-scale underground storage for energy and climate-related gases – natural gas, hydrogen, and carbon dioxide – is becoming increasingly important. While the demand for natural gas as a transition fuel is expected to rise at least until the end of the decade, clean hydrogen is increasingly gaining prominence in long-term decarbonisation plans. At the same time, growing volumes of CO₂ need to be permanently sequestered to reduce its concentration in the atmosphere. Since all the three gases can technically be stored in the same four types of geological formations – salt and rock caverns, deep aquifers, and depleted hydrocarbon fields – their simultaneous underground management raises important technical, economic, and strategic questions that are yet to be comprehensively addressed.

This paper therefore examines the suitability, opportunities, and challenges associated with large-scale geological storage of natural gas, hydrogen, and carbon dioxide, focusing on the four key subsurface structures. It finds that not all formations are equally suitable for all gases: salt and rock caverns and smaller depleted fields are optimal for hydrogen and natural gas storage, while large-scale aquifers and depleted reservoirs are better suited for permanent sequestration of carbon dioxide. Therefore, in the short- to mid-term, CO₂ storage is unlikely to interfere with hydrogen and natural gas operations, given differing physicochemical properties and storage site preferences. It is also noteworthy that while hydrogen and natural gas are expected to be put into storage to be extracted later, for CO₂ by contrast the intention is that it will be sequestered permanently.

The analysis also highlights that while hydrogen and natural gas could technically compete for the same storage structures, hydrogen's significantly higher storage costs and the absence of a liquid market currently limit its competitiveness. Therefore, large-scale hydrogen storage will require targeted government support and strategic policy frameworks. Crucially, the value proposition of hydrogen storage lies in its ability to enhance energy system flexibility, energy security, and long-term decarbonisation, which may justify a premium over natural gas in selected applications. The study concludes by advocating for integrated underground storage planning that moves beyond narrow techno-economic considerations to account for social, political, and systemic factors – ensuring that hydrogen, natural gas, and CO₂ storage are developed in a coherent, complementary, and sustainable manner.



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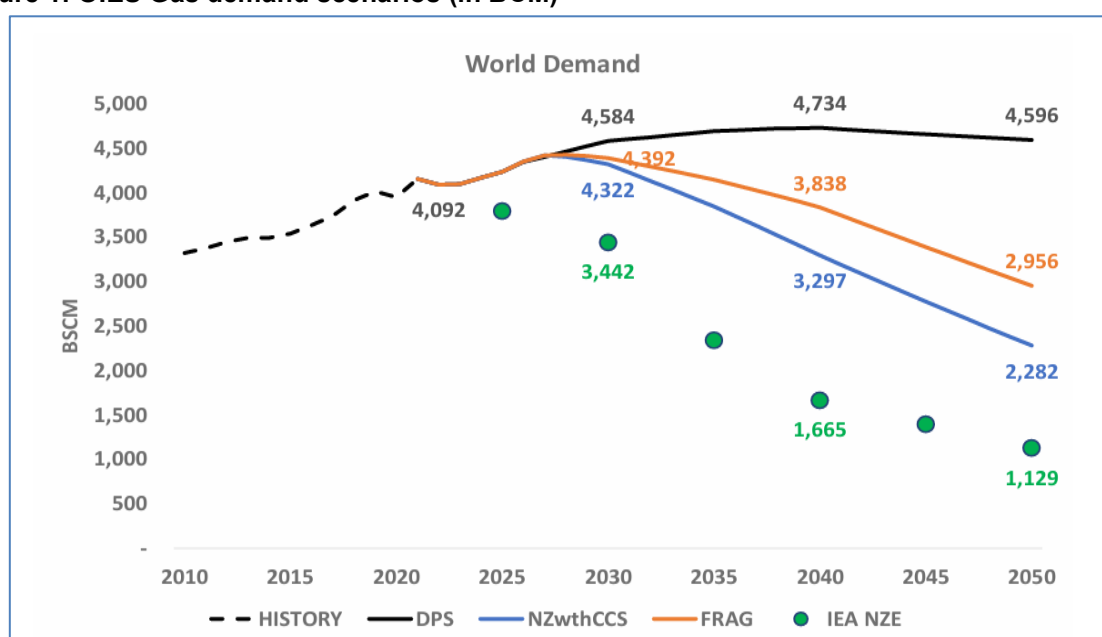
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Introduction

There is now broad acceptance that the global energy system needs to reduce its carbon emissions, despite widely varying views on the required speed and the best approach to be taken. Although many view natural gas, in both its gaseous and liquefied forms, as a transition pathway that could help gradually shift from more polluting fuels, notably coal, to more environmentally friendly alternatives, others criticise attempts to adopt this energy carrier due to the still significant CO₂ and methane emissions associated with use of this fossil fuel. In any case, despite predictions that its role will gradually diminish from the next decade onwards, current demand for natural gas is growing, and many believe this trend is likely to continue until around 2030 (*Figure 1*). As the use of methane in our economies continues to increase, so too does the need for its large-scale storage. According to the latest data, natural gas storage at end-2023 was 437 bcm, with projects under development to increase this to 500 bcm by 2030 (CEDIGAZ, 2024).

Figure 1: OIES Gas demand scenarios (in BCM)

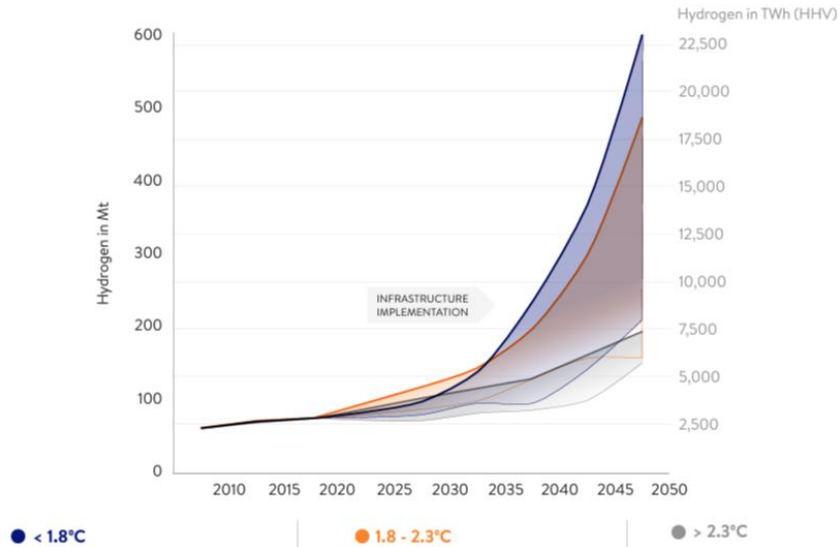


Source: Fulwood (2024).

When it comes to hydrogen, while its global demand still appears relatively modest (only around 97 Mt in 2023), many expect it to skyrocket in the coming years (*Figure 2*) together with a transition to “clean” hydrogen. For instance, S&P Global Commodities Insights estimate it to increase by a factor of 3.3 by 2050 (Hydrogen Insight, 2023), as it will supposedly be driven by a wide range of sectors, with power generation, aviation, and heavy industry constituting the core demand sectors (Hydrogen Insight, 2024). Overall, despite the fact that mid-century hydrogen demand estimates vary significantly – from approximately 150 Mtpa to around 600 Mtpa – and that some experts are more conservative about the volume of clean H₂ required to decarbonise our economies, it is widely recognised that the demand for clean hydrogen will grow, as an indispensable element for achieving our climate targets (World Energy Council, 2021). In this connection, governments worldwide have started setting specific targets for the volumes of clean H₂ that need to be produced and consumed in the foreseeable future, with the European Union’s REPowerEU plan – calling for 20 Mt of green H₂ to be generated within and imported to the EU by 2030 – being among the most ambitious (European Commission, 2022). While these targets are now seen as unachievable, it is clear that growing hydrogen production, particularly when linked with intermittent renewable power generation will need to be linked with significant quantities of H₂ storage. In this context, since, like in the case of natural gas, underground storage of hydrogen appears to be the only option for large-scale use, the need for such storage is also likely to become more significant in the years ahead.



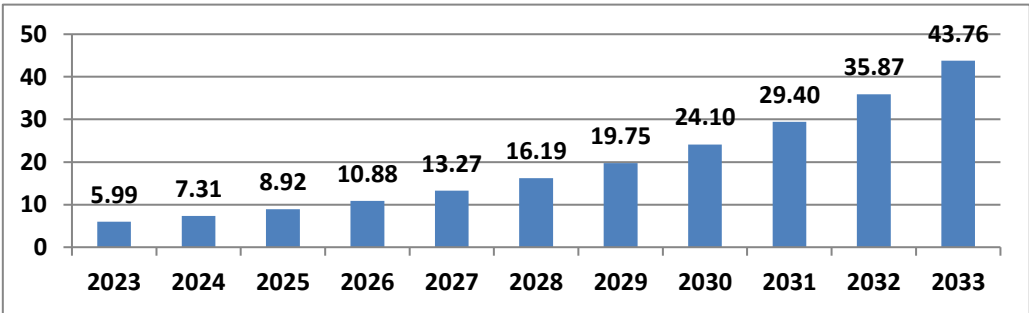
Figure 2: Range of hydrogen demand assessments by 2050



Source: World Energy Council (2021).

Although a growing number of countries are viewing renewables-based ‘green’ hydrogen as the ‘holy grail’ of decarbonisation, many experts believe it is unlikely that the green hydrogen sector will ramp up fast enough to meet global climate targets, given substantial technology constraints that still exist at present (Friedmann, 2022 and Patonia and Poudineh, 2022). In this context, other ‘colours’ of H₂ will need to come into play, and ‘blue’ hydrogen produced from fossil fuels with CCS seems to be the most likely candidate to take the lead due to its significantly lower costs and incomparably larger scale of production (Dickel, 2020)¹. Additionally, some industrial processes that are hard to electrify or with process emissions of CO₂, e.g. cement production, cannot be fully decarbonised, which highlights CCS as one of the few viable options currently available (Barbhuiya et al, 2024). That is why, with growing trends in decarbonisation, the volumes of carbon dioxide that will have to be sequestered will only rise, in line with growth in the CCS market (Figure 3). In this case, again, given that underground geological formations represent the only currently existing option for safe permanent storage of large volumes of CO₂, this may reduce such structures available for temporary storage of natural gas and hydrogen.

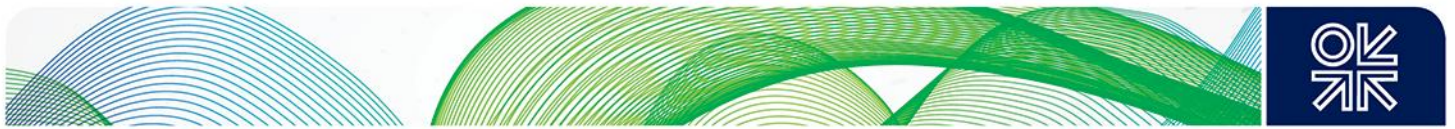
Figure 3: Global carbon capture and storage market size projections (USD billion)



Source: Adapted from Precedence Research (2024).

Since it currently seems extremely unlikely that hydrogen will immediately and completely replace natural gas and overnight become the fuel that entirely dominates the energy landscape (Gilbert, Bazilian, and Gross, 2021), at some point in the near future, it is likely that large volumes of temporary storage for both hydrogen and natural gas will need to co-exist. While batteries can increasingly

¹ Similarly, other ‘colours’ of hydrogen such as ‘turquoise’ is often expected to play an important role in the future hydrogen market, as CO₂ emissions are largely avoided (RAG Austria, 2023).



provide short-term energy system balancing, large scale storage of both natural gas and hydrogen is expected to be required to for medium and long term system balancing. While there is a clear and significant difference in that (except where used for enhanced oil recovery or carbon capture and utilisation (CCU) applications) CO₂ is expected to be stored permanently, while both natural gas and hydrogen will be stored temporarily, it remains unclear whether the simultaneous underground storage of all three gases may or will lead to potential overlaps, challenges, or conflicts of interest.

To explore these questions, this paper analyses the three gases in terms of their suitability, opportunities, and challenges for large-scale underground storage through the focus on the most suitable geological structures. It therefore aims to answer the questions of whether simultaneous large-scale storage of hydrogen, carbon dioxide, and natural gas will be technically and economically feasible and how use of available underground geological structures should be prioritised.

The outline of the paper is as follows. Section 1 analyses the three gases in terms of their technical suitability for large-scale underground storage. It then focuses on the key types of geological formations potentially suitable for the storage of each of them to evaluate the most suitable and least suitable options for each gas. Section 2 considers the economic aspects of large-scale underground storage of hydrogen, natural gas, and carbon dioxide in the respective geological formations from the perspective of key costs and potential commercial models most suitable for making the storage of each of the gases economically attractive. Going beyond techno-economic analysis, Section 3 then analyses other aspects that should be taken into account when considering, planning, and managing underground storage of the three gases. The final section provides recommendations and concluding remarks.

1. Technical analysis

1.1 Characteristics of hydrogen, natural gas, carbon dioxide at surface conditions and their suitability for geological storage

The suitability of hydrogen, natural gas, and carbon dioxide for underground storage is influenced by their distinct physical and chemical characteristics. These relate, among others, to molecular mass, (energy-) density, dynamic viscosity, solubility in water, and compressibility factor. Combined with specific features of geological formations used for the storage of these gases such as permeability, caprock integrity, reservoir porosity, and the reaction with reservoir rocks, fluids and indigenous microbes, these characteristics are some of the core determinants of their storage feasibility, safety, and efficiency.

- **Hydrogen**

On account of its physical characteristics, hydrogen is widely understood to be a difficult substance to handle, including for transportation and storage. One of the very few features of hydrogen that is potentially favourable for underground storage is its low solubility in water. This reduces the likelihood of H₂ migrating through water-bearing formations and minimizes the risk of chemically altering surrounding rock structures (Bach, Crostogino, and Kruckeberg, 2019). However, this characteristic alone cannot outweigh the numerous other challenges associated with storing hydrogen underground, particularly when it comes to being pumped and stored in geological formations for long periods.

In particular, hydrogen has a molecular mass of approximately 2.016 g/mol, which contributes to its high diffusivity in solids and therefore necessitates the use of rocks with very low permeability to effectively contain it underground (Teodoriu and Bello, 2020). Its low density under ambient conditions, around 0.08375 kg/m³, makes hydrogen highly buoyant, leading to a significant risk of leakage and presenting challenges for long-term containment (Cappellani, 2022). Additionally, its low viscosity (0.88×10^{-5} Pa-s) further increases the potential for leakage and necessitates stringent requirements for caprock integrity² (Liu, Teodoriu, and Bello, 2015). Furthermore, the high

² This also applies to the storage of natural gas.



compressibility factor of hydrogen (0.9-1.005) complicates pressure management during storage, resulting in increased costs and material stress (Züttel, 2003). Lastly, the air-diffusion coefficient indicates that hydrogen has a high diffusion rate (0.61 cm²/s), which, in the event of a leak, can heighten dispersion risks and necessitate robust containment and detection measures³ (Abdalla, Hagemann, and Hemme, 2018).

- **Natural gas**

Natural gas has a molecular mass of approximately 16.043 g/mol, which results in slower diffusion rates compared to hydrogen and therefore allows for its more stable containment but still requires secure caprock to prevent escape (Teodoriu and Bello, 2020). Under ambient conditions, natural gas has a density of about 0.6682 kg/m³, which presents moderate buoyancy; thus, effective sealing is essential to mitigate atmospheric escape risks (Cappellani, 2022). Although it is higher than that of hydrogen, the solubility of natural gas in water is relatively low at 0.0023 g/100 g, indicating a reduced likelihood of migration through aquifers while maintaining the integrity of surrounding geological formations (Bach, Crotogino, and Kruckeberg, 2019). Furthermore, with a dynamic viscosity of approximately 1.10×10^{-5} Pa-s, natural gas is less prone to leakage than hydrogen, which simplifies its containment and handling processes (Liu, Teodoriu, and Bello, 2015). Besides, the compressibility factor for methane ranges from 0.95 to 0.997, allowing for efficient storage but requiring monitoring to prevent over-pressurization during injection (Züttel, 2003). Finally, the air-diffusion coefficient for natural gas is lower than that of hydrogen at 0.20 cm²/s, resulting in a moderate leakage risk that still necessitates effective monitoring strategies (Abdalla, Hagemann, and Hemme, 2018 and Borello et al, 2024).

- **Carbon dioxide**

Unlike hydrogen and natural gas, which are typically stored underground for later retrieval and use, the storage of carbon dioxide is generally intended as a form of permanent disposal, particularly in the context of climate mitigation efforts. With the exception of buffer storage for subsequent CCU applications and enhanced recovery of hydrocarbons, underground CO₂ storage is not designed for reuse, but rather to isolate emissions from the atmosphere on a geological timescale. This puts significant constraints on the strategy and use of geological formations for its storage.

In addition, in contrast to hydrogen and natural gas, carbon dioxide is normally considered for underground storage not in the form of gas but as a pseudo (supercritical) fluid – i.e., CO₂ in the state achieved at pressures above 7.38 MPa and temperatures exceeding 31.1°C (IPCC, 2005 and Bachu, 2008). This is because supercritical CO₂ offers significant advantages over its gaseous form due to its unique physical properties, which combine the density of a liquid with the mobility of a gas (ibid). Consequently, this high-density state reduces storage volume requirements, while its low viscosity facilitates injection into porous geological formations.

CO₂'s high solubility in water (approximately 0.169 g/100 g) primarily creates risks for underground storage related to potential strong interaction between CO₂ and the reservoir brine which will lead to the dissolution of significant amounts of CO₂ into the aquifer water (Bach, Crotogino, and Kruckeberg, 2019). This is, however, one of the few characteristics that decrease its suitability for large-scale underground storage, since overall, CO₂ is considered easier to store underground than both hydrogen and natural gas due to several reasons.

Carbon dioxide has a higher molecular mass (~44.009 g/mol) and lower diffusivity compared to both hydrogen and methane. Although it requires higher pressures for efficient storage, these conditions generally enhance its retention in geological formations (Teodoriu and Bello, 2020). At ambient conditions (approximately 25°C and atmospheric pressure), CO₂ has a density of around 1.842 kg/m³; however, under typical supercritical storage conditions, its density increases significantly to approximately 600-800 kg/m³, which reduces buoyancy risks and promotes stable long-term trapping within geological formations (Cappellani, 2022).

³ At the end of the day, the stored volume will be compressed to the same maximum pressure as the natural gas previously in the formation. However, due to hydrogen's lower compressibility and lower energy density per Nm³, around 3.5 times more volume is required to store the same amount of energy as natural gas.



Its dynamic viscosity under supercritical conditions ($\sim 1.47 \times 10^{-5}$ Pa-s) is higher than that of hydrogen and methane, making CO₂ less prone to leakage and simplifying containment efforts (Liu, Teodoriu, and Bello, 2015). Furthermore, the compressibility factor for supercritical CO₂ ranges from approximately 0.274 to 0.57, indicating that it can be stored at higher densities compared to hydrogen or methane, enhancing overall storage efficiency (Züttel, 2003). Finally, CO₂ has a low air-diffusion coefficient of about 0.14 cm²/s, resulting in minimal leakage risk and making containment easier while requiring simpler monitoring protocols (Abdalla et al., 2018).

1.2 Types of geological formations suitable for the storage of hydrogen, natural gas, and carbon dioxide

At the moment, underground storage of hydrogen, natural gas, and carbon dioxide is mostly being associated with four types of geological formations: salt caverns, rock caverns, deep aquifers, and depleted hydrocarbon reservoirs⁴. These structures potentially offer specific geophysical and chemical properties critical for secure, large-scale, and long-term storage of such gases. Since each formation type offers unique advantages and challenges, these features should be carefully evaluated based on specific project requirements and regional geology. Therefore understanding the characteristics of different geological formations is crucial when considering underground storage options for hydrogen, natural gas, and carbon dioxide.

• Salt caverns

Salt caverns are typically constructed through solution mining in salt deposit formations. First a well is drilled into the salt layer to allow access and to determine the quality of the deposit. As a second step water is pumped downhole through an inner well and withdrawn via the annulus to dissolve the salt. In this way a cavity is formed which needs to be kept under pressure (water or gas) to keep it stable. The core type of rock in salt caverns is halite, which has excellent sealing properties due to its low permeability (Makhatab, Poe, and Mak, 2015), which provides an effective trapping mechanisms for gases. Salt's natural ability to self-seal under pressure enhances its effectiveness as a storage medium (Ślizowski, Urbańczyk, and Serbin, 2010).

Salt caverns are typically found at depths ranging from 300 to 1,800 meters and can withstand operational pressures ranging from 3.5 to 27 MPa (*Table 1*). The typical storage volume range for salt caverns can vary significantly but often falls between 30,000 and 1 million cubic meters (Cyran and Kowalski, 2021). These caverns are suitable for both static and high-frequency cycling operations due to their rapid injection and withdrawal capabilities. That is why, in terms of technical suitability for storage, salt caverns are highly effective for high frequency cycling – e.g. short-term balancing – and therefore would be extremely suitable for hydrogen and methane (ibid). In addition to that, due to their self-sealing properties and stability under high pressure, they also appear to be highly suitable for the underground storage of carbon dioxide in the form of supercritical liquid (IPCC, 2005 and Bachu, 2008).

At the same time, although they may seem to be highly suitable for the storage of all three gases, salt caverns also have their disadvantages. In particular, their relative scarcity and uneven distribution of suitable salt deposits around the globe as well as high initial capital costs appear to be the main ones. Therefore, although technically feasible, storage of CO₂ in salt caverns will represent a very expensive disposal option⁵.

⁴ Other potential options include, but are not limited to, abandoned mines and shallow subsurface formations – both of which have limited storage volumes and a high risk of leakage – as well as coal seams, which have low permeability, making gas injection challenging, and are generally unsuitable for H₂ due to chemical incompatibility with coal (Liu and Pei, 2021 and Thomas and Chen, 2024).

⁵ In principle, it could make sense to repurpose an existing salt cavern if no longer in use. However, the current focus for CO₂ storage is on saline aquifers and depleted fields (*Table 3*), while basalts and unmineable coal seams are considered as other potential options.



Table 1: Types of geological formations for underground storage of gases

Characteristics		Salt caverns	Rock caverns	Deep aquifers	Depleted hydrocarbon reservoirs
Typical origination		Man-made		Natural	
Typical formation method		Solution mining (dissolving salt)	Excavation (blasting, drilling)	Sedimentation, compaction, cementation, and hydraulic connectivity	Natural depletion (after oil and gas extraction)
Core type of rocks		Non-porous rocks		Porous rocks	
Typical formative rocks		Halite (rock salt)	n/a	Halite (rock salt)	n/a
		n/a	Granite		
			Limestone		
			Sandstone		
			Basalt		
		n/a	Conglomerate		
			Unconsolidated sediments		n/a
Trapping mechanism	H ₂	Physical			
		Capillary			
		n/a	Mineral		
			Adsorption		
		Dissolution	n/a		
	CH ₄	Physical			
		Capillary			
		n/a	Adsorption		
	CO ₂	Physical			
		Dissolution			
		Capillary			
		Mineral	n/a	Mineral	
n/a		Adsorption			
Typical depth range (m)		300-1,800	10-1,000	400-2,300	300-3,000
Operation pressure range (MPa)		3.5-27	0.1-20	3-31.5	1.5-28.5
Typical storage volume range (m³)		100,000-1,150,000	50,000-500,000	1,000,000-1,000,000,000	10,000,000-1,000,000,000
Type of storage	Static/low cycling	High	High	Very high	Extremely high
	High-frequency cycling	Extremely high	Moderate	Low	Moderate
Technical suitability for storage	H ₂	Extremely high	Medium	Medium	Very high
	CH ₄	Extremely high	Medium	Medium	Very high
	CO ₂	High	High	Very high	Extremely high
Estimated cost	H ₂	Medium	Very high	Medium	Low
	CH ₄	Medium	Medium	Very high	Low
	CO ₂	Medium	Very high	Medium	Low

Source: Ślizowski, Urbańczyk, Serbin (2010), Susan (2019), Cyran and Kowalski (2021), GIE (2021), Papadakis and Ahluwalia (2021), Schneider (2021), Tarkowski and Uliasz-Misiak (2021), Tarkowski, Uliasz-Misiak, and Tarkowski (2021), Chen et al (2022), Epelle et al (2022), Małachowska et al (2022), Wei et al (2022), Battelle (2023), Miocic et al (2023), Hellerschmied et al (2024), Tarkowski et al (2024), Talukdar et al (2024).

Characteristics:

Unfavourable conditions	Slightly favourable/Neutral	Favourable	Highly favourable	Extremely favourable
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Table 2: Key advantages and disadvantages of the main types of geological formations for underground storage of gases

Gas	Salt caverns	Rock caverns	Deep aquifers	Depleted hydrocarbon fields
Key advantages				
H₂	<ul style="list-style-type: none"> • Impermeability • Rapid injection and withdrawal capabilities 	<ul style="list-style-type: none"> • Potential utilisation of existing infrastructure 	<ul style="list-style-type: none"> • Potentially suitable for long-term static storage of H₂ 	<ul style="list-style-type: none"> • Substantial storage capacity • Use of natural gas as a cushion gas accelerates development
CH₄	<ul style="list-style-type: none"> • Lower cushion gas requirements • Self-sealing properties • High security • Proven suitability for high frequency cycling 	<ul style="list-style-type: none"> • Established operational practices and technology • Potentially viable option where salt caverns and depleted reservoirs may not be available 	<ul style="list-style-type: none"> • Flexibility in resource use due to potential repurposing from water-bearing formations 	<ul style="list-style-type: none"> • Proven containment capacity • High safety • Well-mapped geology • Existing infrastructure • Significant storage volume • Often favourable pressure and depth conditions optimising storage efficiency
CO₂	<ul style="list-style-type: none"> • Impermeability resulting in effective leakage prevention 	<ul style="list-style-type: none"> • Established technology for gas storage 	<ul style="list-style-type: none"> • Significant storage potential • Widespread availability • Reduced leakage risk due to CO₂'s dissolution in brine and potential mineralisation over time 	<ul style="list-style-type: none"> • Proven capacity and sealing mechanisms from past hydrocarbon trapping
Key disadvantages/ challenges				
H₂	<ul style="list-style-type: none"> • Risk of hydrate formation (clogging) • Cushion gas hard to fully extract when repurposing from natural gas to hydrogen • Higher safety requirements due to missing pore structure 	<ul style="list-style-type: none"> • Potential significant leakage due to hydrogen's high diffusivity • Typical need for reinforcement to minimise leakage • Limited flexibility due to slower injection and withdrawal rates 	<ul style="list-style-type: none"> • High cushion gas requirements • Requirement for careful engineering to avoid hydrogen migration 	<ul style="list-style-type: none"> • May require additional sealing and monitoring to prevent leaks • Potential 'contamination' by remaining hydrocarbons
CH₄	<ul style="list-style-type: none"> • Expensive and time-consuming leaching process 	<ul style="list-style-type: none"> • Higher construction costs • Slower operational capabilities 	<ul style="list-style-type: none"> • High cushion gas requirements • Potential environmental concerns • Limited operational flexibility 	<ul style="list-style-type: none"> • Higher cushion gas requirement
CO₂	<ul style="list-style-type: none"> • Limited storage volume • Usually designed for high-frequency cycling • Corrosion of facilities 	<ul style="list-style-type: none"> • Limited capacity • Risk of destabilisation, dissolution and leakage in certain rock types due to CO₂'s acidic nature • Limited containment security • Costly to develop and maintain 	<ul style="list-style-type: none"> • Requirement for more extensive assessment and monitoring to ensure containment • More complex and costly than depleted reservoirs 	<ul style="list-style-type: none"> • Interactions with existing hydrocarbons may complicate storage dynamics⁶

In addition, when hydrogen is stored in salt caverns, hydrate formation can cause clogging (*Table 2*) (Beriain et al., 2020). Furthermore, due to hydrogen's high diffusivity, storage infrastructure requires additional reinforcement to minimise leakage, which can in turn limit operational flexibility (Malachowska et al., 2022). Finally, this leaching process may be costly and time-consuming with higher construction costs and lower operational capabilities (Makhatab, Poe, and Mak, 2015).

⁶ Low pressure may be an issue initially, as supercritical conditions would not be reached immediately, posing a risk of operating in a two-phase environment. However, interaction with hydrocarbons is not a concern, as hydrogen would either replace natural gas or dissolve into oil.



- **Rock caverns**

Rock caverns are usually located at depths ranging from 10 to 1,000 meters and can operate under pressure ranges from 0.1 to 20 MPa. The typical storage volume range for rock caverns is often between 1,000 and 100,000 cubic meters, and they are generally more suited for static or low-cycling operations due to their construction method and the nature of the surrounding rock (Miocic et al, 2023). Therefore, they have moderate technical suitability for hydrogen and methane (especially for dynamic seasonal storage) (ibid). In addition, as CO₂ is normally stored in its supercritical phase, rock caverns are unlikely to be extremely suitable here due to high costs, containment risks, pressure management issues, as well as overall limited proven use (IPCC, 2005 and Bachu, 2008).

Similarly to salt caverns, some of the most significant disadvantages of rock caverns, in addition to their availability being limited to specific geological conditions, are their high construction and operational costs. This is primarily due to factors such as limited containment security, which necessitates extensive assessment and monitoring to ensure safety, making them more complex and costly (*Table 2*). For hydrogen and natural gas, this also relates to higher cushion gas requirements, limiting operational flexibility, and the need for careful engineering to avoid gas migration, which may pose risks through existing fractures or well infrastructure.

- **Deep aquifers**

In general, deep aquifers could be defined as geological formations that consist of porous rock layers capable of storing significant volumes of fluids, which typically originate from sedimentary processes where sandstone or limestone accumulates over geological timeframes (Papadimas & Ahluwalia, 2021) (*Table 1*). Therefore, the core types of rocks in deep aquifers are typically sandstone or limestone, which exhibit high porosity and permeability characteristics necessary for effective gas movement and storage, and the formation method involves natural deposition processes that create permeable layers (ibid). The trapping mechanisms in deep aquifers, in turn, primarily rely on the presence of impermeable caprocks that prevent gas escape (Susan, 2019).

Deep aquifers can be usually found at depths ranging from approximately 400 to around 2,300 meters and typically operate under pressure ranges from 3 to 31.5 MPa (*Table 1*). The ordinary pore space range can also vary but often falls between 50,000 and a million cubic metres (Wei et al, 2022). These formations are generally suitable for static or low-cycling operations due to their geological characteristics and are not ideal for dynamic high-frequency storage. That is why they are typically most suitable for permanent storage of carbon dioxide and exhibit only moderate suitability for temporary storage of hydrogen or natural gas (ibid).

At the same time, storing CO₂ as supercritical fluid in deep aquifers can also pose significant challenges. This is because of various factors, such as geological uncertainty associated with potential heterogeneity, faults and fractures of the aquifer, and therefore leakage risks, complex pressure management, and need for long-term monitoring (*Table 2*). In these circumstances, utilising deep aquifers for large-scale storage of gases is likely to be associated with additional costs, both capital and operating (*Table 1*).

- **Depleted hydrocarbon reservoirs**

Depleted hydrocarbon reservoirs are former oil or gas fields that have been exhausted of economically recoverable resources. These formations typically originate from geological processes that allowed hydrocarbons to accumulate in porous rock layers sealed by impermeable caprocks for millions of years (Tarkowski et al., 2022). In them, the core types of rocks are sandstone or limestone, while shale formations often serve as sealing layers that help prevent gas migration out of the reservoir (Epelle et al., 2022) (*Table 1*). The trapping mechanisms rely on these geological seals that previously contained hydrocarbons.

Suitable depleted hydrocarbon reservoirs are generally located at depths ranging from 300 to 3,000 meters and can operate under pressure ranges from 1.5 to around 28.5 MPa (ibid). Their storage volume range varies widely but often falls between 50 million and billions of cubic meters (Talukdar et al., 2024). Since, these reservoirs are broadly suitable for both static and high-frequency cycling



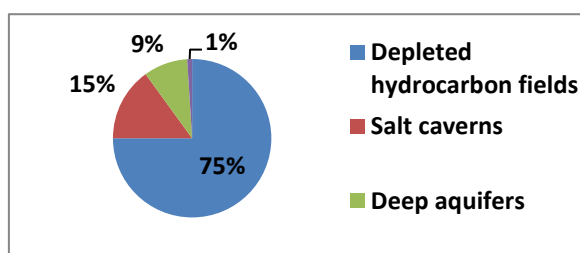
operations, they can be used for the large-scale storage of all the three gases (Małachowska et al., 2022). Typically smaller depleted fields are likely to be more suitable for short-term cycling of methane and hydrogen while larger fields are likely to be suitable for permanent CO₂ sequestration.

At the same time, just like all the previous geological formations viewed for the underground storage of hydrogen, natural gas, and carbon dioxide, depleted hydrocarbon reservoirs are not flawless. Their utilisation for both H₂ and CH₄ may require additional monitoring measures to confirm integrity (*Table 2*). Besides, particularly when storing hydrogen, it can be technically ‘contaminated’ with remaining hydrocarbons or through microbial reactions, which will require post-extraction purification resulting in additional costs.

1.3 Potential challenges and overlaps

As observed, while all four key types of geological formations could potentially be suitable for the storage of hydrogen, natural gas, and carbon dioxide, their suitability levels vary. This variation arises not only from the differing geological characteristics of salt caverns, rock caverns, deep aquifers, and depleted hydrocarbon reservoirs but also (if not primarily) from the specific physicochemical properties of each of the gases viewed in this article. Here, given hydrogen’s unique challenges for underground storage, coupled with its expected high-frequency cycling storage mode, salt caverns represent a highly suitable option. However, since salt caverns are also often the preferred choice for similar high-frequency cycling storage of natural gas, potential conflicts of interest may arise with gas storage operators. This scenario is less likely to occur for carbon dioxide as deep aquifers and large-scale depleted hydrocarbon reservoirs are more likely to be utilised for its storage instead.

Figure 4: Approximate share of key geological structures currently used for natural gas storage

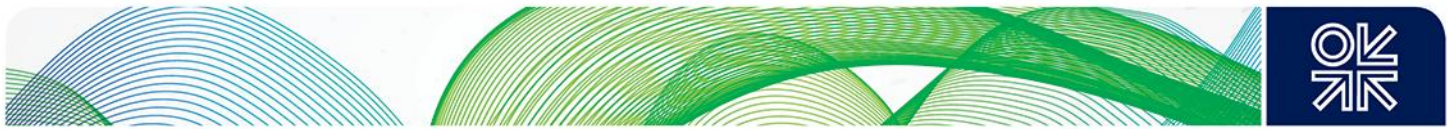


Source: Adapted from IGU (2022) and EIA (2024).

At present, for CO₂ underground injection, depleted hydrocarbon fields are primarily used when so-called ‘enhanced recovery’ – i.e. hydrocarbon production accelerated by injecting CO₂ to increase reservoir pressure and improve hydrocarbons’ flow – is taking place (IEA, 2015). Therefore, although depleted fields can also serve as pure storage sites for carbon dioxide, at the moment, most CO₂ storage that is not associated with enhanced oil and/or gas recovery is expected to take place in deep (saline) aquifers (*Table 3*). Since neither hydrogen nor natural gas are currently focusing on prioritising the active development of this type of geological storage (*Figure 4*), CO₂ storage is unlikely to significantly interfere with the hydrogen-natural gas storage interplay in the short- and mid-term future.

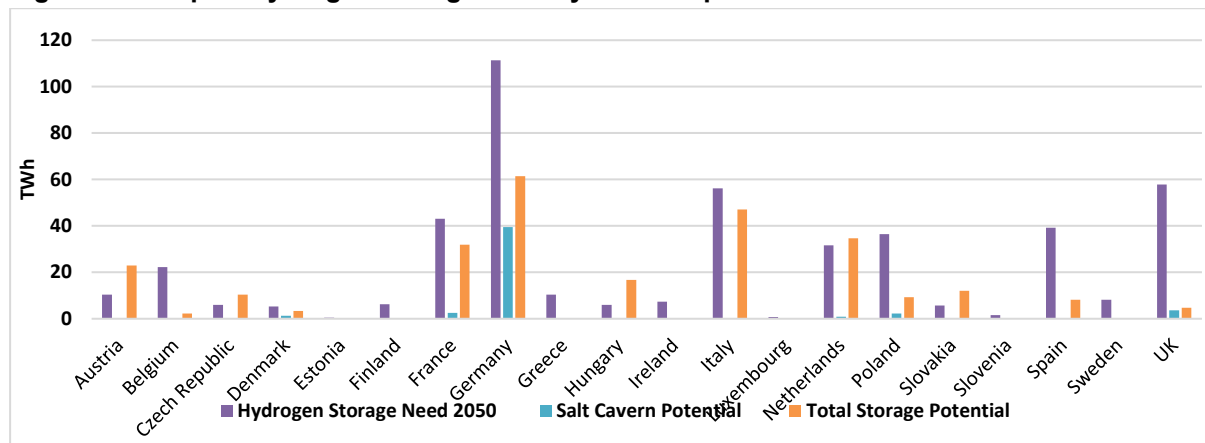
There are diverse views on the requirements for and availability of suitable large scale underground hydrogen storage. In a recent report, Germany – Europe’s greatest hydrogen enthusiast – is claiming that its salt caverns alone could cover not only national but also European hydrogen storage needs, which would suggest that both the country and the continent could avoid the use of depleted hydrocarbon fields (BMWK, 2025). According to this view, relying solely on this type of geological formation in Germany would be sufficient to accommodate 80 TWh of energy by 2045 (Germany’s expected hydrogen storage demand), in addition to meeting the hydrogen storage needs of the rest of the continent⁷ (FCW, 2025). This, however, does not align with Gas Infrastructure Europe’s earlier assessments of Europe’s hydrogen storage potential, which clearly demonstrated the need to extend

⁷ Since the German Weißbuch disregards many scientific recommendations (including those from various experts and a prestudy by Dena (2024) on the potential of depleted fields; this statement may be misleading.



storage reliance beyond salt caverns to include other geological formations, such as depleted hydrocarbon fields (*Figure 5*). The view also differs from a Royal Society report which estimated that the UK alone could need more than 100 TWh of salt cavern hydrogen storage to provide security of electricity supply in a net zero system (Royal Society, 2023)

Figure 5: Europe's hydrogen storage need by 2050 vs. potential



Source: Gas Infrastructure Europe (2021).

While the exact trajectory of hydrogen storage development in Europe and globally will largely depend on how and at what scale hydrogen demand evolves, concentrating all of the continent's H₂ storage capacity within the facilities of a single country is unlikely to be politically acceptable. In this regard, although salt deposits themselves are relatively widespread, the specific geological conditions required to create salt caverns suitable for large-scale underground gas storage are not universally available (*Figure 6*). As such, other options – notably hydrogen storage in depleted hydrocarbon fields – will likely need to be pursued. The feasibility of developing salt cavern storage depends on a combination of factors, including the depth, thickness, and location of the salt formation, as well as external considerations such as land use restrictions, environmental regulations, and the availability of supporting infrastructure. For this reason, even those countries on the continent with a suitable combination of these factors for developing such H₂ storage options are unlikely to be able to rely on them exclusively.

After salt caverns, small to mid-scale depleted hydrocarbon fields appear to represent the other most suitable option for temporary storage. However, following this logic, more overlaps are likely to arise, as each of the three gases – hydrogen, natural gas, and potentially carbon dioxide (in the long-term perspective) – can be stored in these formations at large scale and potentially at lower costs. Hence, although depleted oil and gas fields are generally significantly more numerous than other suitable structures, increasing stored volumes of hydrogen will automatically reduce the potentially available capacity for natural gas, particularly where hydrogen storage is developed in repurposed natural gas storage facilities. In addition, in the longer term, as CCS becomes more widely adopted and increasing amounts of CO₂ are captured and stored not only in deep aquifers but also depleted fields, even more pressure may be put on the storage of natural gas and hydrogen⁸.

⁸ In this respect, a critical question to ask here is *whether the declared targets for hydrogen utilisation and CO₂ sequestration will need to be met to achieve decarbonisation objectives – and, if so, how quickly*. Although hydrogen and CCS are widely considered indispensable components of broader decarbonisation strategies, these technologies actively compete with alternatives such as renewables, batteries, and nuclear power. Since these alternatives often represent cheaper and more reliable elements in the overall decarbonisation picture, some believe that reaching the net-zero carbon targets may not necessarily require those dramatic volumes of generated clean hydrogen or captured and stored carbon dioxide (Hydrogen Insight, 2024). Since currently, high costs and relatively small scalability remain two of the most significant barriers to the ramp-up of both clean hydrogen and CCS (Lambert and Patonia, 2024), another critical technical consideration is *the speed at which these technologies can be scaled up and reduced in cost so that they truly become important competitors to other sustainable technologies helping to reach the common decarbonisation objective*.



Table 3: Selected key underground storage projects for H₂ and CO₂ (FID reached, under construction, and operational) as of 2024

#	Project name		Location	Key contributor/s	Current status	(Expected) start of operations	Storage formation	Announced capacity (t/y)
Hydrogen								
1	Aquamarine		Kardoskút, Hungary	Hungarian Gas Storage	Under construction	2025	Depleted gas field	TBD
2	Bad Lauchstädt Energy park		Bad Lauchstädt, Germany	Uniper, VNG AG	FID	2027	Salt caverns	4,500
3	HYBRIT		Svartöberget, Sweden	SSAB, LKAB and Vattenfall	Operational	2022	Rock caverns	TBD
4	HyCAVmobil		Rüdersdorf, Germany	EWE, German Aerospace Center's Institute of Networked Energy Systems	Operational	2023	Salt caverns	6
5	Hychico Underground Hydrogen Storage		Comodoro Rivadavia, Argentina	Hychico	Operational	2016	Depleted gas field	TBD
6	HYPOS-H2 Research Caverns		Teutschenthal, Germany	VNG Gasspeicher, ONTRAS Gastransport, DBI – Gastecnologisches Institut, Fraunhofer IMWS	Under construction	2024	Salt caverns	623
7	HypSTER	First Phase	Etrez, France	Storengy, Armines-Ecole Polytechnique, INOVYN, ESK, Element Energy, INERIS, Axelera	Operational	2023	Salt caverns	3
		Second Phase			Under construction	2026		44
8	Krummhörn NG storage		Krummhörn, Germany	Uniper	FID	2024	Salt caverns	~21
9	Underground Sun Storage - Rubensdorf		Gampern, Austria	RAG Austria AG, Axiom Angewandte Prozesstechnik GmbH, Energie AG Oberösterreich	Operational	2023	Depleted gas field	~87
10	EUH2STARS		Various locations in Upper-Austria and Hungary	RAG Austria	Operational	2025	Depleted gas field	~31,000
11	WestKüste 100		Brunsbüttel, Germany	Raffinerie Heide, Hynamics, Holcim, OGE, Ørsted, Stadtwerke Heide, Thüga, Thyssenkrupp	Under construction	2024	Salt caverns	TBD
12	HyStorage		Bierwang	Uniper, etc.	Operational	2023	Depleted gas field	1.8
Carbon dioxide								
1	Central Louisiana Regional Carbon Storage (CENLA) Hub (Wilcox) phase 1		Alexandria, LA, USA	CapturePoint Solutions, Energy transfer	Under construction	2024	Deep aquifers	2 million
2	China Energy Guohua Jinjie Power		Shaanxi, China	China Energy	Operational	2021	Depleted gas field	150,000
3	China Energy Taizhou power		Jiangsu, China	China Energy	Operational	2023	Depleted gas field	500,000
4	Climeworks Mammoth Project		Hellisheiði, Iceland	Climeworks, Carbfix	Under construction	2024	Deep aquifers	~36,000
5	Climeworks Orca				Operational	2021		4,000
6	CNOOC Enping offshore CCS		Pearl River Mouth Basin, South China Sea	CNOOC	Operational	2023	Deep aquifers	300,000
7	Eastern Louisiana Clean Hydrogen Complex (LA)		Darrow, LA, USA	Air Products	Under construction	2026	Deep aquifers	5 million
8	Gorgon CCS		Barrow Island, WA, Australia	Chevron, Shell, ExxonMobil, Osaka Gas, Tokyo Gas, Chubu Electric Power	Operational	2019	Deep aquifers	~4 million
9	Illinois Industrial Carbon Capture and Storage		Decatur, IL, USA	ADM	Operational	2017	Deep aquifers	500,000
10	Midwest AgEnergy Blue Flint ethanol (ND)		Underwood, ND, USA	Blue Flint Sequester Company LLC, Harvestone Low Carbon Partners, Ag Energy Group LLC	Operational	2023	Depleted oil field	200,000
11	Moomba Carbon Capture and Storage		Cooper Basin, SA, Australia	Santos, Beach Energy	Under construction	2024	Depleted gas field	1,700,000
12	Northern Lights Phase 1		North Sea, Norway	Shell, TotalEnergies, Equinor	Under construction	2024	Depleted gas field	1,500,000
13	Qatar LNG		Ras Laffan Industrial City, Qatar	QatarEnergy LNG, ExxonMobil	Operational	2019	Deep aquifers	2,100,000
14	Quest		Alberta oil sands, AB, Canada	Canadian Natural Resources Limited, Shell, Chevron Canada	Operational	2015	Depleted oil field	1,100,000
15	Red Trail Energy BECCS Project		Richardton, ND, USA	Plains CO2 Reduction Partnership, Energy & Environmental Research Centre, Red Trail Energy	Operational	2022	Depleted oil field	180,000
16	Sleipner		Sleipner West gas field, Norway	Equinor, Eni	Operational	1996	Depleted gas field	1 million
17	Snohvit CO2 capture and storage		Snohvit gas field, Norway	Equinor, Petoro, TotalEnergies, Eni, Wintershall	Operational	2008	Depleted gas field	700,000
18	Uthmaniyah CO2-EOR demonstration		Uthmaniyah field, Saudi Arabia	Saudi Aramco	Operational	2015	Depleted oil field	800,000

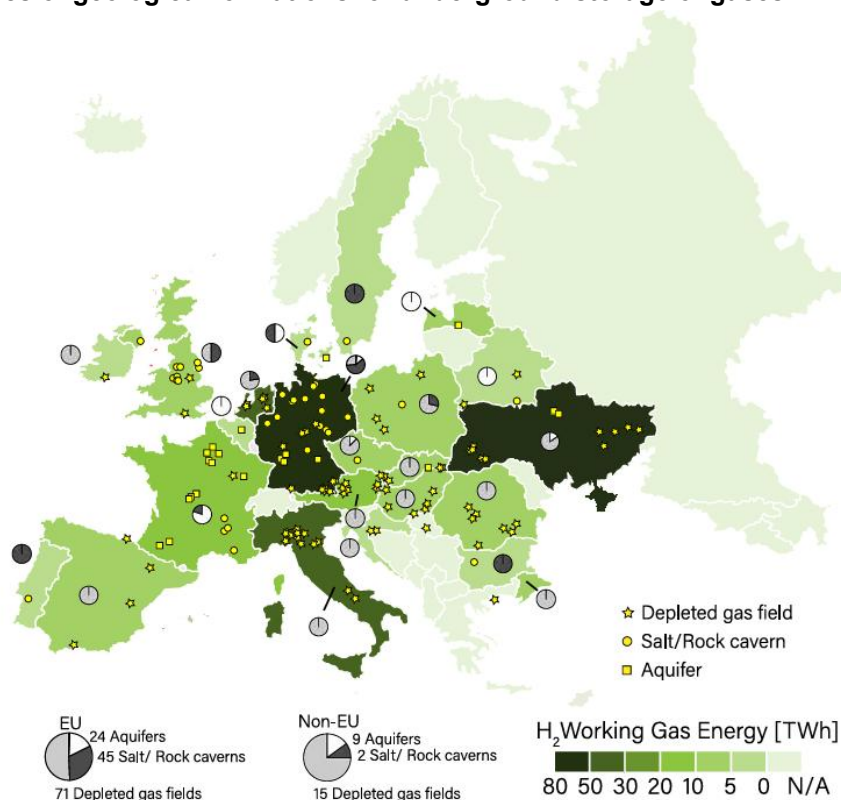
Source: Adapted from Global CCS Institute (2024), IEA (2024a) and IEA (2024b).



Therefore, in the foreseeable future, the key overlaps are most likely to occur between natural gas and hydrogen storage, particularly in the use of salt caverns and depleted hydrocarbon reservoirs. For a combination of reasons, including the relatively early stages of technological development, high costs, and technical limitations, it is less likely that deep aquifers and rock caverns – while representing the remaining options – will significantly alter this situation.

At the same time, such potential overlaps and conflicts of interest are only likely to arise if the hydrogen market expands to the extent expected, making large-scale H₂ storage economically viable. Therefore, analysing the technical prerequisites and characteristics of geological storage for these gases alone will not be sufficient to determine which options should be prioritised in the future. Therefore the next section considers an economic evaluation to further inform the analysis.

Figure 6: Types of geological formations for underground storage of gases



Source: Adapted from Talukdar et al (2024).

2. Economic analysis

2.1 Business models for underground storage of hydrogen, natural gas, and carbon dioxide

At the moment, business models for the storage of hydrogen, natural gas, and carbon dioxide, look completely different. In fact, currently only natural gas represents an internationally traded commodity and has well established markets both in Europe and the US. Therefore, in those markets, natural gas storage can normally be justified on the basis of different market pricing across the year, where typically gas is lower priced at times of low demand which incentivises its injection, with withdrawal at times of higher demand and hence higher pricing. This enables market players to make a margin on the differential between the two.

For hydrogen storage, in turn, a similar broad principle could apply that H₂ should be injected into storage at times of abundant production in excess of demand and withdrawn from storage when



demand exceeds available supply (for instance during Dunkelflaute periods⁹). However, given the hydrogen market is currently at a very early stage of development, there is not (yet, and probably not for some time) a market price for hydrogen. Thus, a mechanism to incentivise investors to develop hydrogen storage is also missing at the moment.

On the other hand, it should be noted that much of European gas storage was built at the time of monopoly gas utilities (Le Fevre, 2013). Therefore, it is uncertain whether market forces would provide investors sufficient certainty to invest in enough storage in a mature gas market. For hydrogen storage, the incentive for investors to commit significant capital expenditure looks even more uncertain. For instance, although the UK government is developing plans for a hydrogen storage business model, it has not yet been tested in practice (DESNZ, 2024). It seems clear more generally, however, that initially government support will be needed to motivate investors to build hydrogen storage. In the long-term, once a hydrogen market has developed (but that is unlikely to be much before 2050), market signals may prompt when to inject and when to withdraw from hydrogen storage. That is why, at the current stage, although both H₂ and CH₄ could technically compete for the same storage volumes in salt caverns and depleted hydrocarbon fields, the hydrogen sector is not economically ready to do so.

CO₂ storage, in turn, is fundamentally different since it is about locking away carbon dioxide for the very long term (ideally forever)¹⁰. Therefore, its storage is not dynamic, as there is no injection/withdrawal cycle like with methane or hydrogen, since after injection into storage carbon dioxide will not be perceived as a product to be used later. In these circumstances, the only incentive to store CO₂ has to stem from some form of government policy, either from carbon pricing (e.g. through a cap-and-trade system like the EU ETS or a direct carbon tax) or where a government entity directly purchases the carbon dioxide for its sequestration. In this context, the UK government in recent years has been doing quite a lot of work on business models for CO₂ capture, transport, and storage (DESNZ, 2025). Nevertheless, it is also not yet evident how successful these will be. In any case, as demonstrated in Section 1, regardless of the success on the development of a viable business model for CCS, large-scale underground storage of carbon dioxide is unlikely to significantly interfere with the hydrogen-natural gas interplay.

2.2 Economics of underground storage of hydrogen and natural gas

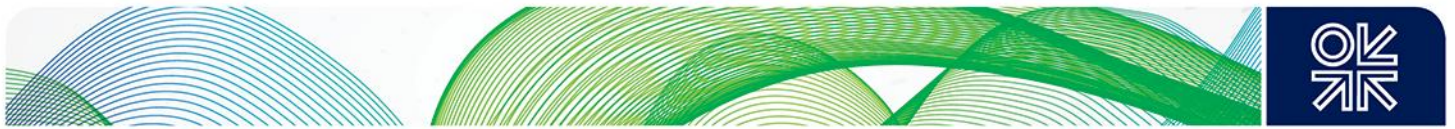
Drawing on decades of experience in the construction and operation of underground gas storage facilities, it is important to emphasize that no typical underground gas storage facility exists. This is especially true for hydrogen storage, given the relative novelty of such projects. Consequently, broad generalisations regarding cost structures for a 'typical' underground hydrogen storage facility are not feasible. This is so because each geological formation considered for underground hydrogen storage must undergo a detailed, site-specific evaluation and extensive storage engineering analysis to determine its suitability and cost implications.

That is why the economic viability and cost structure of underground hydrogen storage projects are highly dependent on the unique geological and physical characteristics of the storage site. Here, key factors include porosity, permeability, water saturation and drive, diffusion and saturation behaviour within the reservoir, microbiological activity, geochemical conditions, depth, and the formation type and thickness. These geological variables significantly impact the planning and execution of drilling operations, including the number, dimensions, and trajectory (vertical or horizontal) of boreholes, which are critical cost drivers.

Moreover, operational parameters such as production history – ranging from the original natural gas or hydrocarbon content to the transition to hydrogen – play a crucial role in cost determination. Smaller storage sites generally incur higher development costs per unit of capacity compared to larger sites. However, the development of large underground H₂ storage sites is contingent on sufficient and concrete storage demand as well as the existence of a robust hydrogen supply and withdrawal

⁹ Dunkelflaute (German for 'dark doldrum') is generally described as a period of several consecutive days in which low of minimal energy can be produced by renewable energy sources, such as solar or wind (Next Kraftwerke, 2025).

¹⁰ However, for landlocked countries, it would need buffer storage until a European CO₂ Backbone is fully developed.



infrastructure, including the necessary hydrogen volumes to justify investment. Additional factors influencing costs include reservoir pressure levels and the configuration of upstream and downstream hydrogen grids¹¹.

While companies such as Uniper, Storengy, RAG Austria have pioneered the construction and operation of H₂ storage facilities in Europe, there remain substantial uncertainties. Lessons learned during on-going operations highlight that the design and management of such projects will likely need to evolve with each cycle and project, reflecting site-specific conditions and requirements. These operational insights are closely held proprietary knowledge but underline the fact that hydrogen storage infrastructure cannot be developed by simply transferring natural gas storage methodologies one-to-one. Therefore, since the cost structure of underground hydrogen storage is inherently site-specific and influenced by a complex interplay of geological, operational, and market-driven factors, any serious cost estimation must be based on a concrete project with thoroughly assessed technical and economic parameters.

- **Storing hydrogen and natural gas in salt caverns**

As described in the previous section, salt caverns represent one of the two most suitable types of geological formations for the large-scale storage of both hydrogen and natural gas, followed by depleted hydrocarbon fields. Going beyond technical characteristics and expanding analysis to the economic aspects will give us better understanding of the most possible avenues for the future development of the H₂ sector. Overall, while, at the moment, natural gas storage utilises mature infrastructure, proven regulatory frameworks, and predictable revenue streams, hydrogen storage still remains at an earlier stage of market maturity. This status introduces heightened uncertainty, greater infrastructure costs, and higher financial risks, all of which directly affect the calculations of levelised cost of storage (LCOS). Additionally, hydrogen storage presents several economic considerations that differ from those of natural gas, mainly due to variations in cavern size, infrastructure compatibility, compression power requirements, and gas density.

Overall, under the same cavern size and pressure conditions, hydrogen's lower density and compressibility mean lesser volumes (scf or Sm³) of hydrogen can be stored compared to natural gas (Lin, Maraggi, and Evans, 2025). In addition, since hydrogen has a lower energy content per standard volume than methane (about one-third the energy density of natural gas), storing hydrogen in a cavern of the same size will not only yield a smaller gas volume but also a significantly lower energy content (ibid). Therefore, at the same conditions of volume, pressure, and temperature, a cavern will store significantly less energy as hydrogen than as natural gas.

Under typical assumptions of pressure and temperature gradients, hydrogen generally requires a cavern volume 1.15 to 1.45 times larger than that of natural gas to store an equivalent gas volume at standard surface conditions (Juez-Larre et al, 2019). This is primarily due to hydrogen's lower compressibility. Moreover, when considering energy content, hydrogen's lower volumetric energy density results in a significantly smaller total stored energy, which has important implications for the economic and operational feasibility of storage projects.

In this context, more detailed economic comparisons will require consideration of specific cavern scenarios. For example, a salt cavern of 320,000 m³ at a pressure of 3,000 psi and a temperature of 54°C would allow for the storage of around 1.966 billion standard cubic feet (Bscf) of hydrogen and 2.313 Bscf of natural gas (Lin, Maraggi, and Evans, 2025). This means that, under identical conditions, only about 85% of the natural gas volume could be stored if replaced with hydrogen (ibid).

When differences in energy density are taken into account, the situation becomes even more striking. Specifically, with hydrogen containing roughly 290 Btu per standard cubic foot compared to natural gas at around 1,000 Btu per standard cubic foot, an equivalent storage volume would hold significantly less total energy if filled with hydrogen instead of natural gas. As a result, under identical pressure and temperature conditions, hydrogen storage in salt caverns would equate to storing only about 25% of the energy content of natural gas (Lin, Maraggi, and Evans, 2025).

¹¹ For example, hydrogen grids in Austria are currently being designed without compressors to maintain required pressure levels, which impacts the design and cost of associated infrastructure.



At the moment, LCOS for hydrogen in salt caverns is generally estimated to be almost twice as high on a volumetric basis as for natural gas (*Table 4*). However, when assessed on an energy-equivalent basis – which is a more meaningful comparison – it can be around six times higher (Shuster et al., 2021 and Gasunie, 2024). This higher LCOS is primarily driven by the specialized infrastructure required for hydrogen storage, which demands higher initial capital investments and incurs greater operational expenditure compared to natural gas infrastructure. A significant cost driver here is the development of salt caverns for hydrogen storage, which necessitates larger cavern volumes under comparable working gas conditions (*Table 4*). The creation of these larger caverns involves extended development timelines and increased resource requirements, such as water for solution mining, leading to higher capital expenditures (Amos, 1998 and Gasunie, 2024).

Table 4: Approximate economic metrics and cost components of underground storage of hydrogen and natural gas in salt caverns¹²

Economic metrics and cost components	Natural gas	Hydrogen	Relative difference
Levelised volumetric cost of storage (USD/MMscf)¹³	2,052	3,868	1.9× higher for hydrogen
Levelised cost per energy unit (USD/MMBtu)¹⁴	2.05	11.90	5.8× higher for hydrogen
CapEx (USD)	32,891,000	39,000,000	~25% higher for hydrogen
Drilling	7,584,000	9,620,000	~27% higher for hydrogen
Solution mining costs	6,194,000	7,172,200	~16% higher for hydrogen
Compression costs	5,470,224	7,390,000	
Land, mineral and construction costs	15,883,000	17,720,000	~12% higher for hydrogen
Cushion gas (non-depreciable)	1,283,288	3,155,625	2.4× higher for hydrogen
OpEx (USD/MMscf)			
Electricity for compression	204.52	270.12	~32% higher
Surface equipment operation and maintenance	135.47	169.60	~25% higher
Well operation and maintenance	111.94	139.93	~25% higher
Financial structure			
Debt-to-equity ratio	1.5	0.6	Lower leverage for hydrogen
Cost of debt (%)	~3–4	~4–6	Higher debt cost for hydrogen
Cost of equity (%)	~9–11	~11–14	Higher equity cost for hydrogen
Investment metrics			
Equity nominal IRR (%)	8.0	13.0	Higher required return for hydrogen
Project-level nominal IRR (%)	4.4	9.7	Higher due to risk profile
Investor payback period	11 years	9 years	Shorter payback for hydrogen due to higher returns

Source: Adapted from Lin, Maraggi, and Evans (2025).

¹² Notably, this economic comparison is based on a uniform market and regulatory framework for both scenarios, intentionally disregarding regional market disparities. In practice, actual projects must consider the impact of local market conditions and regional regulatory differences, which can substantially affect project economics.

For this comparison, the storage size of 320,000 m³ at a pressure of 3,000 psi and temperature of 54°C was used.

¹³ MMscf = million standard cubic feet.

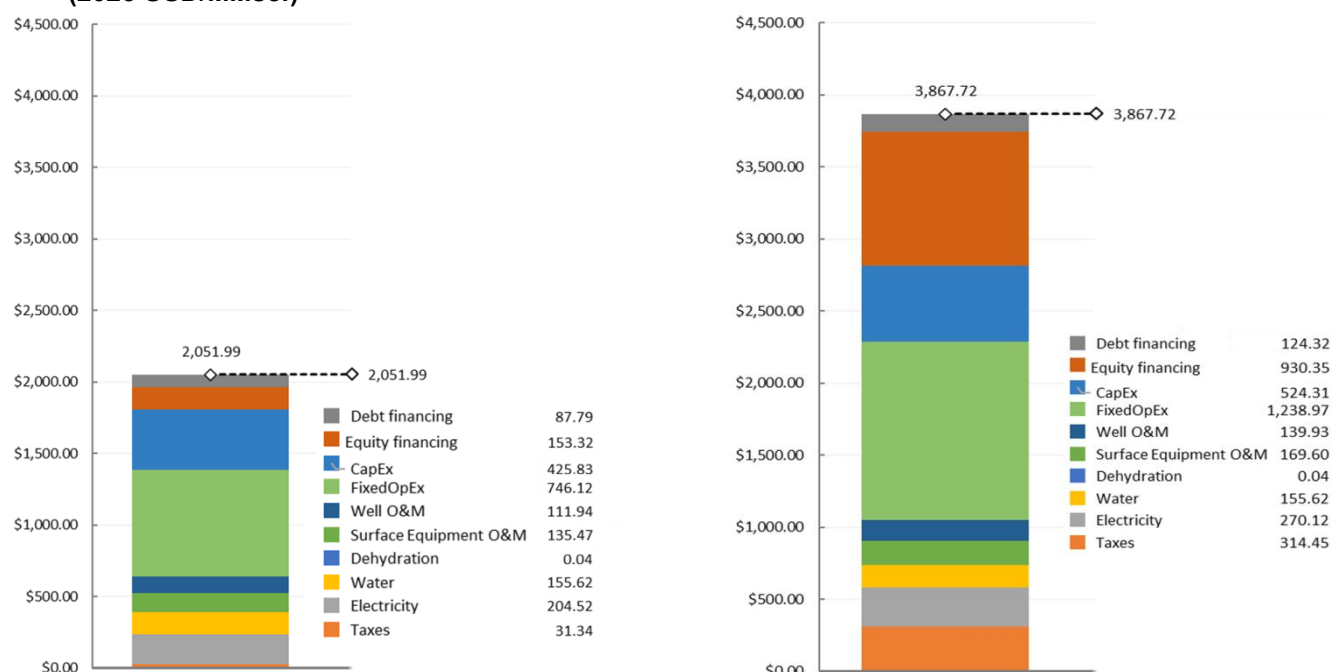
¹⁴ MMBtu = million British thermal units.



Apart from that, hydrogen compression generally requires significantly higher energy input due to H₂'s lower density and higher compressibility factor (Z-factor). Specifically, compressing hydrogen from lower to higher operational pressures typically demands 30-35 percent more energy per energy unit compared to natural gas for equivalent volumetric injection rates (Elberry et al, 2021 and Owate, 2025). While the capital investment in compression equipment does not scale linearly with energy consumption, hydrogen compression facilities inherently involve elevated capital and operating costs (Rong et al, 2024 and Lin, Maraggi, and Evans, 2025).

In addition, infrastructure designed for hydrogen storage must address the risks of hydrogen-induced steel embrittlement by employing specialised steel grades, advanced sealing technologies, and tailored cement compositions (ibid). These enhanced material characteristics increase infrastructure material costs by approximately 20 percent compared to natural gas systems, regardless of pipeline size differences (Ilyushechkin et al, 2023 and Krella, 2025). Similarly, hydrogen has higher monitoring and maintenance requirements due to potential embrittlement, erosion, and microbial consumption.

Figure 7: Real levelised cost breakdown of natural gas and hydrogen storage (2025 USD/MMscf)

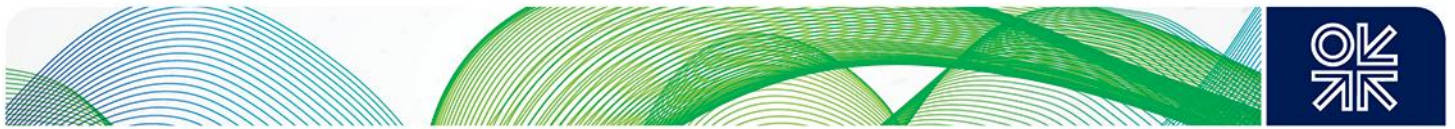


Source: Lin, Maraggi, and Evans (2025).

Moreover, the requirement for cushion gas to maintain operational pressures results in significantly higher costs for hydrogen compared to natural gas (Table 4). In salt caverns, although the ratio of cushion gas to working gas is similar for both hydrogen and natural gas, the cost disparity arises from the higher cost per unit of hydrogen (Amos, 1998 and Gasunie, 2024)¹⁵. Overall, hydrogen storage facilities also incur higher electricity costs, primarily driven by increased compression energy needs.

While there are minor differences in permitting and licensing costs for hydrogen compared to natural gas, with hydrogen costs being higher, these disparities are reflective of the nascent stage of hydrogen projects and the increased rent paid for land due to landowners' perceptions of emerging technologies (Lin, Maraggi, and Evans, 2025 and Owate, 2025). These costs can vary significantly from one project to another but are not major factors in the overall cost comparison between hydrogen and natural gas (Figure 7).

¹⁵ For porous reservoirs, the proportion of cushion gas to working gas can be greater for hydrogen, exacerbating the cost difference between hydrogen and natural gas in terms of cushion gas expenses (Shuster et al, 2021).



Financing costs additionally contribute to the economic differences between hydrogen and natural gas storage (*Table 4*). Due to higher perceived technological and market risks, hydrogen projects typically operate with lower leverage ratios, leading to elevated costs of debt and equity capital. All of these factors collectively result in significantly higher overall financial expenses for hydrogen storage, which are estimated to be about 5.8 times greater on an energy basis than those for natural gas (*Table 4*).

- **Storing hydrogen and natural gas in depleted hydrocarbon fields**

In principle, hydrogen storage in depleted hydrocarbon fields offers a technically viable yet similarly complex alternative to salt cavern storage, with several unique operational and economic considerations (Peacock et al, 2022 and Jahanbakhsh et al, 2024). While the general principles of underground gas storage remain similar (i.e. injecting gas into a subsurface reservoir and withdrawing it as needed), the characteristics of depleted oil and gas fields introduce additional challenges, particularly when repurposing them for hydrogen (Peacock et al, 2022).

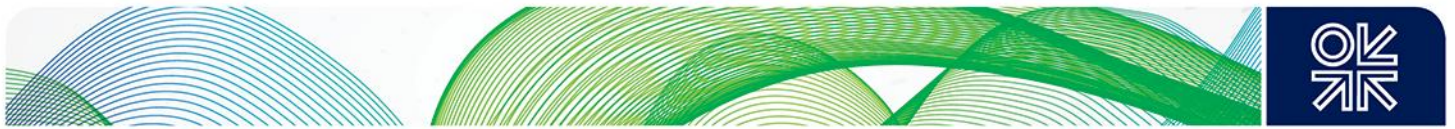
In this context, one of the most important factors is reservoir integrity, specifically the assessment of caprock performance (Lin, Maraggi, and Evans, 2025). Unlike natural gas, which has a long operational history in these settings, hydrogen's lower molecular weight and higher diffusivity increase the risk of migration through potential weaknesses in the caprock (Jahanbakhsh et al, 2024). Traditional hydrocarbon reservoirs often require minimal additional testing before being used for natural gas storage, but storing hydrogen necessitates rigorous integrity verification, including advanced sealing strategies (ibid). This requirement can add significant upfront capital costs and extend project timelines, and will therefore most likely directly influence both feasibility studies and investment decisions (Peacock et al, 2022).

Another distinction lies in well design and regulatory obligations. In natural gas storage projects, it is common practice to retain production wells for injection and withdrawal while potentially adding additional wells, a process typically accompanied by moderate regulatory scrutiny. Hydrogen, however, presents a different set of challenges. Due to potential reactions with legacy well casings and materials, it is generally considered safer and more efficient to require new or comprehensively modified injection-withdrawal wells, specifically designed for hydrogen's physical properties and flow characteristics. These wells often feature smaller-diameter casings and enhanced safety systems, which increases regulatory complexity, extends permitting timelines, and elevates development costs relative to natural gas projects (Peacock et al, 2022).

Surface infrastructure and pipeline compatibility also differ markedly between the two gases¹⁶. While hydrogen's lower density might suggest smaller pipeline diameters for equivalent withdrawal rates, its tendency to cause embrittlement in high-yield-strength steels prevents the simple repurposing of existing pipelines (Lin, Maraggi, and Evans, 2025). Infrastructure originally designed for natural gas transport typically uses high-strength steels that, while ideal for hydrocarbon applications, are vulnerable to hydrogen embrittlement (ibid). This necessitates the installation of entirely new pipelines or the extensive retrofitting of existing ones with lower-yield-strength materials and advanced sealing solutions to prevent leaks at valves, flanges, and joints. These infrastructure adjustments represent a substantial capital commitment, eroding one of the main economic advantages of using depleted fields: the availability of pre-existing assets (Peacock et al, 2022).

Operational energy requirements also differ due to hydrogen's lower density and compressibility. As mentioned before, compressing hydrogen to suitable reservoir pressures requires significantly more energy than compressing natural gas to equivalent conditions, directly impacting operational expenditure (Jahanbakhsh et al, 2024). This increased energy demand becomes particularly significant in storage scenarios where repeated cycles of injection and withdrawal are expected (Peacock et al, 2022).

¹⁶ This is not an issue specific to depleted fields. In addition, as many pipelines are reportedly H₂-ready, this claimed disadvantage may not be that significant.



A further operational complexity of hydrogen storage in depleted reservoirs is the need for gas purification¹⁷. While natural gas storage operations typically involve minimal gas treatment, hydrogen storage faces the issue of residual natural gas within the reservoir from previous hydrocarbon production¹⁸ (ibid). Therefore, ensuring high-purity hydrogen at withdrawal requires on-site gas separation units, further increasing both capital expenditure and on-going operational costs (ibid). In this connection, these systems must be capable of efficiently isolating hydrogen from residual hydrocarbons, which represents an engineering and economic consideration absent in most natural gas storage operations (Peacock et al., 2022).

Monitoring and maintenance regimes also become more demanding. Hydrogen's higher diffusivity, potential for microbial activity, and capacity to induce material embrittlement require continuous surveillance using advanced technologies (Lin, Maraggi, and Evans, 2025). This includes more detailed and frequent integrity assessments of wells, pipelines, and surface infrastructure, as well as the deployment of real-time monitoring systems for pressure, temperature, and gas composition (ibid). These intensive operational requirements further raise ongoing operating expenditures relative to natural gas storage facilities, which typically rely on less frequent and less specialised monitoring¹⁹ (Peacock et al., 2022).

Cushion gas requirements present another economic consideration. Although the percentage of cushion gas needed to maintain adequate reservoir pressure is broadly similar for both hydrogen and natural gas, typically exceeding 50 percent of total working gas capacity, the higher cost per energy unit of hydrogen makes the economic burden of this far greater for hydrogen storage projects (Lin, Maraggi, and Evans, 2025). Here, one way to reduce this cost might involve substituting a portion of the hydrogen cushion gas with a cheaper inert gas such as nitrogen or natural gas²⁰. While this could lower upfront costs, it introduces further operational complexities, including the need for multi-gas separation systems upon withdrawal and more complex gas procurement logistics (ibid). These factors complicate the business case and may offset savings made on initial cushion gas procurement (Peacock et al., 2022).

Collectively, considerations mentioned above demonstrate that while depleted hydrocarbon fields offer significant volumetric potential for hydrogen storage and may avoid the initial costs from creating salt caverns, they generally require far more extensive investment in well integrity, surface infrastructure, and operational safeguards than their natural gas counterparts. That is why, although companies like RAG Austria have successfully pioneered this type of H₂ storage in Europe, the long-term viability of such projects will depend not only on technical feasibility but also on balancing increased capital and operational costs with the strategic advantages of large-scale, long-duration underground storage in support of a future clean hydrogen sector.

3. Additional considerations

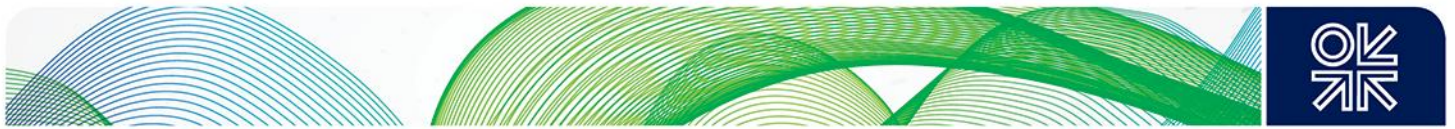
While geological suitability forms the foundation for storage site selection, its techno-economic characteristics are not the only factors that should be considered when deciding on the development of specific storage facilities for hydrogen, natural gas, and carbon dioxide. In fact, the subsurface handling of these gases involves a complex interplay of geological, infrastructural, socio-political, and economic prerequisites that must be carefully balanced. In addition, the specific characteristics of some of these factors may put significant limitations on what options will ultimately be prioritised.

¹⁷ This also applies to aquifer storage where natural gas is present in significant quantities. Interestingly, the USS 2030 project apparently demonstrates that purification is neither a major technical nor cost issue (USS 2030, 2025).

¹⁸ The same applies to salt caverns, which continue to release methane long after abandonment. This was demonstrated when former town gas caverns were converted for natural gas storage, with traces of town gas components still detected after several decades of operation.

¹⁹ In fact, all these measures are already standard practice in natural gas storage. The only additional requirement would be subsurface microbial monitoring, as monitoring for microbially influenced corrosion (MIC) at the surface is already included in existing Monitoring, Measurement, and Verification (MMV) plans.

²⁰ This would unfortunately not be possible with carbon dioxide, as it alters the chemical conditions in the reservoir, reducing storage capacity and triggering biochemical and geochemical reactions with the stored hydrogen. Additionally, the pressure of the CO₂ would be increased to supercritical conditions, resulting in a two-phase flow that is very difficult to manage within a reservoir.



For instance, salt caverns, prized for their low permeability and high cycling capacity, have become the best well-known and preferred choice for hydrogen storage in regions where they are geologically available. Initiatives like Germany's Bad Lauchstädt Energy Park and France's HyPSTER project are based on these geological formations (*Table 3*). At the same time, as Figure 6 demonstrates, salt caverns in Europe are unevenly distributed, which makes this option very spatially limited. Therefore, for example, this absence of salt caverns in Austria forced RAG Austria with partnering companies to lead their pioneering Underground Sun Storage initiative on the readjustment of depleted gas fields (Underground Sun Storage, 2025). As a result, this approach has demonstrated that porous reservoirs can also effectively support seasonal hydrogen storage, which gave hope and paving the way for similar adaptations elsewhere (*ibid*).

At the same time, for a storage project to be technically and economically viable, geological availability should also be supported with the factor of suitable geographical location such as close proximity to demand centres (for natural gas and hydrogen) or, on contrary, remoteness from populated areas, etc. (for carbon dioxide). Following this logic, the Bad Lauchstädt Energy Park was strategically located near significant hydrogen consumption centres – close to the Leuna chemical complex, a major industrial hub in central Germany's 'chemical triangle,' which includes Leuna, Schkopau, and Bitterfeld (VNG Gasspeicher, 2024). Similarly, the HyPSTER project in France was strategically placed at the Entrez natural gas storage site near Lyon – a key industrial area in France, with heavy industries and chemical sectors, among others, which are increasingly considering hydrogen for decarbonisation (HyPSTER, 2023). Not surprisingly, the Underground Sun Storage project, located in Gampern, Upper Austria, is also strategically positioned in a region with robust industrial base, including sectors such as manufacturing, energy, and transportation – i.e. near several potential hydrogen consumption centres both in Upper-Austria and relatively close to the border to Bavaria (Chemical Triangle in Burghausen, Germany) (Underground Sun Storage, 2025).

Overall, proximity to demand centres significantly influences the economic viability of energy infrastructure. Strategic siting near industrial clusters, as demonstrated by the East Coast Hydrogen initiative (East Coast Hydrogen, 2025) and the Port of Rotterdam's hydrogen infrastructure (Port of Rotterdam, 2023), minimizes transportation costs and enhances commercial feasibility. These projects leverage existing industrial ecosystems: Rotterdam's EUR 100 million HyTransPort.RTM pipeline, for example, connects production sites to a future national hydrogen grid (*ibid*). Conversely, remote projects like Australia's Cooper Basin CCS (Australian Climate Leaders Coalition, 2025) face infrastructure challenges due to their distance from consumption hubs, requiring substantial investments in transportation networks. Here, compatibility with existing energy networks further determines success, as seen in the Netherlands' HyStock project (Bilfinger, 2022), which integrates hydrogen storage with national gas grids, while regions lacking such infrastructure encounter higher implementation barriers.

Social acceptance is also very likely to become an extremely important factor in the successful deployment of subsurface gas storage facilities. This is particularly important for carbon dioxide, as public opposition has historically impeded onshore CO₂ storage projects. For instance, Germany's Schwarze Pumpe CCS project started up in 2009 but subsequently was abandoned largely due to strong local resistance and concerns about the risks associated with storing CO₂ near residential areas (Energy Policy Group, 2022). Similarly, the Barendrecht CO₂ storage project in the Netherlands was cancelled after significant community opposition and concerns over safety, despite central government support and adherence to planning processes²¹ (Dolan, James, and Smith, 2020). These setbacks have driven a preference for more expensive and logistically and technologically complex offshore storage of CO₂, where projects like Norway's Northern Lights (operational since 2023) and Denmark's Greensand (which began injections in 2023) have progressed with fewer societal barriers (Global CCS Institute, 2025)²².

²¹ Shell's Barendrecht CO₂ storage project - which since 2007 had planned to inject up to 400 000 t CO₂/year from Shell's Pernis refinery into two depleted gas fields beneath the town - was first delayed when the Barendrecht municipal council voted against it in June 2009, and ultimately cancelled by the Dutch government in November 2010 due to persistent local opposition and the resulting political impasse; no CO₂ was ever injected (Dolan, James, and Smith, 2020).

²² Notably, Northern Lights has already facilitated cross-border CO₂ transport from Belgium and France (Equinor, 2024).



It is likely that, due to its relative ‘novelty’, hydrogen will face analogous scrutiny, especially in residential contexts. At the moment, the UK’s H100 Fife trial, testing hydrogen heating, has encountered mixed public reactions (SGN, 2023). For natural gas, public familiarity has currently reduced resistance, though siting remains contentious, as seen in UK shale gas conflicts (Cotton, Rattle, and van Alstine, 2014). Thus, proactive engagement and offshore alternatives are critical to advancing storage infrastructure. In this respect, the experience of projects similar to the UK’s Teesside industrial hub, which has been successfully storing H₂ in three elliptically shaped salt caverns since 1972, is likely to be useful for the sustainable planning, development, and management of storage facilities.

Finally, broader political and economic uncertainties will continue to shape energy storage infrastructure development. Although the US Inflation Reduction Act (IRA) has accelerated hydrogen and carbon capture investments through tax credits and funding programmes, with projections suggesting it could reduce US emissions by 42 percent below 2005 levels by 2030 (Bain & Company, 2022), potential modifications under the second Trump administration – including possible revisions to tax incentives via budget reconciliation – create uncertainty for long-term project planning (Rabobank, 2024). In the EU, in turn, defence spending priorities are currently increasingly competing with energy transition funding, and the European Council’s March 2025 EUR 800 billion defence plan, coupled with existing commitments to digital and green transitions, risks straining national budgets already constrained by fiscal rules limiting deficits to 3 percent of GDP (Breugel, 2024). These intersecting pressures suggest that only projects combining strong techno-economic viability with political alignment are likely to progress consistently in the foreseeable future.

At the same time, although economic constraints and technical challenges are likely to significantly hamper the progress of storage infrastructure development, the value of the ultimate hydrogen use in terms of decarbonisation and climate change mitigation benefits should, in principle, compensate for the differences in costs when compared to conventionally stored fuels like natural gas. Therefore, apart from focusing on the techno-economic aspects of underground storage options, it is equally important to recognise the value that H₂ storage can offer to meeting decarbonisation objectives within the broader energy system. This value, in turn, is intrinsically linked to hydrogen’s role in various decarbonisation pathways, and storage should not be viewed in isolation but as a crucial enabling component of the wider energy transition. Future research would therefore benefit from examining storage projects’ contribution to system flexibility, energy security, and the integration of intermittent renewable energy sources. If hydrogen generated from intermittent renewables is to play a role in the future energy system, there does not currently appear to be any alternative to investment in significant hydrogen storage.

4. Key findings and conclusions

As the global momentum towards decarbonisation continues to grow, a range of technologies is being explored to bring the net-zero carbon future closer. Among these, the transition from high-emission fossil fuels such as coal to cleaner alternatives like natural gas has been gaining popularity across the world. Wealthier economies are further increasingly focusing on reducing their carbon footprint by adopting technologies such as carbon capture, utilisation, and storage and integrating clean hydrogen into their economic value chains. While limited budgets often position these options as competitors, the inherent complexity of climate change as a ‘wicked problem’²³ necessitates the adoption of multiple approaches, since no single technology offers a comprehensive solution capable of addressing all the challenges associated with global warming.

In this context, the demand for natural gas storage facilities is expected to increase as the use of natural gas continues to rise – a trend that is likely to persist at least until the end of this decade. Similarly, with ambitious plans to ramp up the clean hydrogen sector, the need for large-scale hydrogen storage is also anticipated to grow significantly. At present, underground storage in geological formations represents the most effective and relatively safe method for storing both natural

²³ A wicked problem is a complex issue that is difficult or impossible to resolve due to incomplete, contradictory, and evolving requirements, many of which are hard to identify or define (Johnston and Gulliver, 2022).



gas and hydrogen in large quantities. Furthermore, as carbon dioxide will ultimately need to be permanently sequestered to meet climate goals, the demand for its geological storage is projected to grow substantially in the coming decades.

This study therefore compared the key characteristics of hydrogen, natural gas, and carbon dioxide to explore potential overlaps and respective pathways for sustainable development of their underground storage. In addition to assessing the technical feasibility of such storage solutions, it examined the economic considerations and prerequisites for developing these facilities. Although the exact development pathways for the ramp-up of H₂, CH₄, and CO₂ storage facilities are currently uncertain and will depend on many factors, here are the key findings of the current research along with their implications.

- **Not all geological formations are equally suitable for the storage of hydrogen, natural gas, and carbon dioxide**

At present, four types of geological structures can, in principle, be considered technically viable for the underground storage of hydrogen, natural gas, and carbon dioxide: salt caverns, rock caverns, deep aquifers, and depleted hydrocarbon fields. However, not all formations are equally suitable for all three gases. In general, salt caverns and small to mid-sized depleted hydrocarbon fields are best suited for hydrogen and natural gas, while deep aquifers and large scale depleted reservoirs are more appropriate for carbon dioxide. Moreover, there is no such thing as a 'typical' underground gas storage facility, as each formation requires detailed, site-specific evaluation and engineering analysis to assess its suitability and costs.

- **In the short- and mid-term perspective, carbon dioxide storage will most likely not interfere with the hydrogen-natural gas interplay**

Due to its physicochemical properties, carbon dioxide is generally considered easier to store than hydrogen and natural gas. However, because of differences in these characteristics, as well as the distinct nature of storage – long-term (permanent) sequestration of CO₂ will not restrict temporary storage of H₂ and CH₄ anytime soon. Currently, most hydrogen and natural gas storage projects focus on salt caverns and depleted hydrocarbon fields, whereas CCS initiatives not related to enhanced oil and gas recovery (which takes place in hydrocarbon reservoirs) primarily aim to sequester carbon dioxide in deep aquifers. Therefore, in the foreseeable future, CO₂ is unlikely to compete with H₂ and CH₄ for the same storage volumes and can be stored separately.

- **In principle, both hydrogen and natural gas could technically compete for the same storage volumes in salt caverns and depleted hydrocarbon fields**

While salt caverns are better known for hydrogen storage and are considered very suitable for dynamic storage, they, like all other geological structures, are not evenly distributed everywhere. Therefore, relying solely on them is unlikely to be sufficient for the large-scale development of hydrogen infrastructure. In such circumstances, depleted oil and gas fields will also need to be considered, since, in many (if not most) cases, geology is not something that can be chosen and political considerations are also likely to come into play when energy security issues will be taken into account. Therefore, it is extremely likely that hydrogen storage projects will have to work with what is available – whether that be salt caverns or depleted hydrocarbon fields.

- **However, at the moment, the hydrogen sector is not yet economically ready to compete with natural gas**

Although similar in principle, hydrogen storage is generally much more expensive than natural gas storage. At present, the levelised cost of storage for hydrogen in salt caverns is almost twice that of natural gas on a volumetric basis, and nearly six times higher on an energy-equivalent basis. Similarly, hydrogen storage in depleted hydrocarbon fields is technically viable but faces even greater economic and operational challenges. Compared to natural gas, storing hydrogen in these fields requires extensive investment in reservoir integrity verification, new or comprehensively modified wells, hydrogen-compatible pipelines, and advanced sealing and monitoring systems – eroding the cost advantage of reusing existing infrastructure. Operational costs are also driven up by higher



compression energy demands, the need for gas purification units to remove residual hydrocarbons, more demanding maintenance regimes, and the significantly higher economic burden of cushion gas, given hydrogen's higher per-unit energy cost.

- **Hydrogen storage needs to be promoted through government support schemes**

At present, large-scale underground storage of natural gas is likely to be prioritised over hydrogen storage. The key disadvantage for hydrogen here lies in the absence of a well-developed hydrogen market, in contrast to natural gas. Without a transparent and liquid market price for hydrogen, there is no mechanism to incentivise private investors to absorb the higher upfront and operational costs associated with hydrogen storage infrastructure. In order to incentivise investment in hydrogen storage it is highly likely that strong government support will be required.

- **Yet, the value proposition of hydrogen should ultimately compensate for the difference in cost**

Nevertheless, if hydrogen is to play a significant role in a future decarbonised energy system, hydrogen storage will be required. In this context, the critical policy and commercial question would, therefore, be: what premium will stakeholders be willing to pay for hydrogen, and how much of this premium can be justified by long-term decarbonisation goals, energy security advantages, and system flexibility? That is why, answering this question will require going beyond pure techno-economic domain and looking at H₂ storage from a broader system perspective.

- **For the successful development of underground storage, considerations must extend beyond purely techno-economic factors**

Beyond geological and economic factors, successful underground storage development requires addressing social acceptance, political stability, strategic siting, and systemic interdependencies. Community concerns, policy frameworks, infrastructure integration, and competing storage demands all influence project viability. Ignoring these aspects may lead to delays, opposition, or inefficient outcomes despite technical feasibility and economic attractiveness. More importantly, alongside considering the techno-economic challenges associated with developing various H₂ storage options, the value of hydrogen storage itself should be fully recognised and assessed in relation to its role within decarbonisation strategies and energy system integration, rather than treated as a standalone issue. In this respect, the value of hydrogen storage should, in principle, be able to compensate for the differences in costs.



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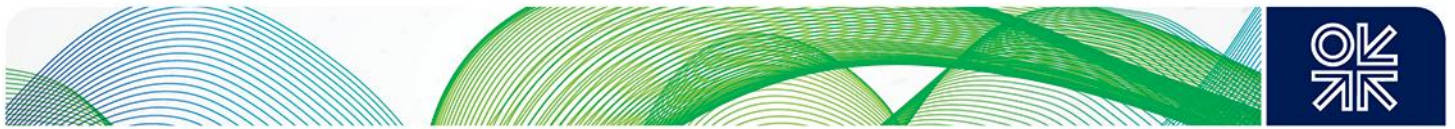
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