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United States Energy Association:

Underground Hydrogen Storage (UHS) in Depleted Reservoirs

Final Report

Subagreement No. 633-2023-004-01

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Disclaimer

Executive Summary

The hydrogen economy offers a potentially sustainable, long-term pathway to support the U.S. decarbonization strategy and energy security. With the increasing attention on decarbonization strategies for the U.S. economy, reliable storage of large volumes of surplus electrical energy from renewable sources (e.g., via conversion to hydrogen) presents challenges and opportunities. Underground geological storage of hydrogen in depleted gas reservoirs (i.e., gas reservoirs or fields once production operations have ceased) has emerged as one of the more attractive options for large-scale, seasonal storage because of its effectiveness and relatively low cost. This study seeks to establish a foundational perspective for policy makers and market-makers with a high-level assessment of the current state of understanding of the potential and challenges for repurposing depleted gas reservoirs for hydrogen storage.

Underground hydrogen storage (UHS) is considered analogous to underground natural gas storage operations that have been successfully implemented for over a century in salt caverns, depleted reservoirs, and aquifers. However, there is minimal operational experience with hydrogen storage in these systems. A typical UHS site aims to provide storage potential to balance seasonal supply and demand fluctuations and meet peak demand to stabilize the power grid. UHS can utilize naturally occurring porous media or engineered structures in the subsurface for viable large-scale and seasonal energy storage capability.

The literature on the current state of understanding and industrial experience for UHS was reviewed to enumerate the advantages, challenges, and operational aspects of the most common storage systems for UHS, namely salt caverns, depleted oil or gas reservoirs, and saline aquifers. The only UHS facilities in operation today are in salt caverns while depleted gas fields have been previously used for storage of hydrogen-rich gas mixtures as well as extensively for natural gas. In addition, ongoing research and exploration efforts in natural hydrogen accumulations are valuable to inform technical considerations and risks associated with storage integrity for UHS in general. The key subsurface considerations of UHS involve hydrogeological, geochemical, microbiological, and geomechanical interactions. The limited understanding of these considerations from modeling and laboratory studies presents fundamental technical gaps such as the possible effects of geochemical reactions and microbial processes, storage-production cyclicity impacts etc. that still need to be addressed by detailed site characterization and field-testing efforts considering realistic operational parameters.

A preliminary analytical-based screening assessment on hydrogen storage performance was developed and implemented to gain insights into the following metrics of hydrogen storage capacity, diffusive losses to the caprock and well deliverability in reservoir conditions representative of depleted gas reservoirs in the U.S. Midwest region. The total available hydrogen storage capacity in depleted gas fields considered in the Midwest region is 41.2 billion tonnes assuming 50% cushion gas fraction which exceeds the projected storage needs of a fully developed hydrogen economy in the U.S. While diffusive losses and well deliverability are site-specific, preliminary results indicate that diffusion of storage gas through caprock is likely not a significant concern. Comparison with analogous storage gases (natural gas and supercritical carbon dioxide [CO_2]) in depleted gas reservoirs leads to the following key takeaways:

- Volumetric storage performance metrics are similar between hydrogen, natural gas and supercritical CO_2.

- The lower mass density of hydrogen in comparison to natural gas and CO_2 implies 1-3 orders of magnitude higher volumes required in the subsurface to store an equivalent mass of hydrogen.
- Diffusive losses through caprock are a larger issue for CO_2 than for hydrogen. In this respect, any caprock with sufficient integrity for carbon capture and sequestration (CCS) should be sufficient for hydrogen.
- Single well deliverability of hydrogen indicates a need for much higher flow rates (about an order of magnitude) to meet the same level of energy demand in comparison to natural gas deliverability. This is a necessary consideration for infrastructure planning and UHS site design.

The literature review includes summary statistics to capture the trends in hydrogen related research and industrial experience which indicates that most aspects of the science of generating, capturing, transporting, and storing hydrogen are reasonably well studied, although some aspects of the behavior of UHS reservoirs, especially at the field-scale, require further study. While UHS in depleted gas reservoirs offers a lucrative storage option to support the envisioned hydrogen economy, primary hurdles for the success of UHS projects are more likely to be social, political, or regulatory considerations. The review noted key gaps in the development of regulatory systems related to production, distribution, and storage of hydrogen, particularly at the state and municipal level. A suite of social considerations also needs further attention, such as low public awareness of hydrogen development, and social and environmental justice considerations around the development of surface and subsurface hydrogen infrastructure. Additional research is needed to resolve the technical challenges and address gaps in understanding of technoeconomics to provide suitable criteria for storage site selection and development. Accelerated reservoir-scale field testing is recommended for successful implementation of storage infrastructure in a regional and ultimately national hydrogen economy. This needs to be coupled with increased attention to proactively understand social considerations that may prove challenging and accordingly plan stakeholder engagement activities. The CCS industry experiences are a valuable guide and starting point for UHS developers approaching these questions.

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1.0 Introduction and Problem Statement

The growing focus on reducing greenhouse gas emissions has reenergized attention on hydrogen (H_2) as a clean fuel source and carbon-free energy carrier. Since free hydrogen can be generated via a broad suite of processes utilizing diverse energy sources, it may be capable of displacing carbon-emitting fuels in industrial processes and some parts of the global energy system. It is a lucrative enabling technology for renewables through long-duration energy storage and for clean power generation.

The United States (U.S.) clean hydrogen market is poised for rapid growth, accelerated by aligned opportunities such as the Hydrogen Hub funding, and multiple tax credits under the Inflation Reduction Act (IRA) including the hydrogen production tax credit to achieve the Department of Energy's (DOE's) Hydrogen Shot (U.S. DOE, 2021a). The U.S., like many countries across the world, has identified the successful deployment of commercial-scale hydrogen as an important element of a strong clean energy economy while enabling our nation's long-term decarbonization goals. The U.S. National Clean Hydrogen Strategy and Roadmap (U.S. DOE, 2023a) presents the government's strategic framework to accelerating clean hydrogen system components of production, transport, storage, and use and a vision for how clean hydrogen will contribute to national decarbonization goals across multiple sectors in the future. The DOE's Hydrogen Program, led by the Office of Energy Efficiency and Renewable Energy (EERE), actively supports pathways to enable commercial liftoff via research and development efforts for technology validation, analysis, system development and integration, safety codes and standards, education, and workforce development. Other pertinent drivers to accelerate hydrogen technology development towards commercialization also include investments to achieve decarbonization goals across the public and private sectors, especially in hard-to-abate industrial and heavy-duty transportation sectors.

The Strategy and Roadmap (U.S. DOE, 2023a) is based on prioritizing three key strategies to effectively develop and adopt clean hydrogen in the U.S.

- Targeting strategic, high impact uses for clean hydrogen
- Reducing the cost of clean hydrogen
- Focusing on regional networks

Hydrogen storage is a critical component to ensure the above strategies can be implemented for a reliable and robust clean hydrogen supply chain. The DOE's Pathways to Commercial Liftoff: Clean Hydrogen report (U.S. DOE, 2023b) features hydrogen storage during the industrial scaling (~2027-2034) and long-term growth (post-2035) phases to balance variability in supply (associated with renewables) and seasonal fluctuations in demand. While salt cavern storage, compressed gas tank, and pipelines provide low-cost distribution and storage in the near term, geologic storage is expected to anchor hydrogen infrastructure as clean hydrogen production scales to achieve economic, large-scale storage networks in the long term.

Ahluwalia et al. (2019) presented an economic analysis of various grid-scale bulk hydrogen storage options such as pressure vessels, cryogenic storage, and geologic storage (in caverns and porous media) that establishes the cost-effectiveness of geologic storage. Subsurface offers significant additional advantages over above-ground storage facilities for large-scale storage such as:

- Lesser footprint: subsurface storage leverages higher volumetric energy density of hydrogen resulting in lesser area requirement required for large storage volumes.
- Secure storage: subsurface storage is less susceptible to sabotage and environmental risk factors.
- More availability: suitable subsurface storage reservoirs offer orders of magnitude higher storage capacity and are widely available.

Geologic storage of hydrogen is considered conceptually comparable to underground natural gas storage operations. However, hydrogen storage field experience in these systems is a significant gap with most of the hydrogen storage experience encountered in salt caverns for industrial use applications. Several research programs have been undertaken over the last decade, primarily in Europe, dedicated to process understanding and computational modeling of hydrogen storage in geologic systems, such as HyUnder (Landinger et al., 2014), H2STORE (Pudlo et al., 2013), ANGUS+ (Kabuth et al., 2017*)*, Underground Sun Storage (RAG, 2020) and SHASTA (Goodman Hanson et al., 2022) in the U.S.

Among the geologic storage options, depleted reservoirs present a highly attractive storage option as they are well characterized with demonstrated performance from historical operations, have proven structural trap, offer substantial storage capacity and are cost-effective with existing infrastructure that can be leveraged for hydrogen storage. However, the technical viability of hydrogen storage in these systems is relatively less developed due to few existing operations in comparison to salt caverns. This study aims to substantiate the dynamics of hydrogen in depleted reservoirs based on existing fluid storage operations such as carbon dioxide (CO_2) and natural gas storage analogs in these systems. Insights gained from literature and industry experiences are summarized for fundamental understanding of the technical and operational considerations in using these systems for large-scale seasonal underground hydrogen storage (UHS). The study goals include high-level recommendations to advance the state-of-the-art understanding of design and integrity aspects of subsurface storage and related infrastructure in our efforts to ensure clean hydrogen can be available.

This report presents insights into considerations for depleted reservoirs to be utilized for UHS and the fate of hydrogen in these systems in comparison with natural gas and CO_2 storage analogs. The understanding of hydrogen dynamics in the subsurface is achieved by the successful implementation of a preliminary performance assessment framework for analyzing feasibility of UHS options. Chapter 2 provides an overview of geologic UHS options such as salt caverns, deep saline aquifers, depleted oil and gas fields and other storage options. Chapter 3 summarizes historical analogous industrial gas storage experience including the scant UHS experience to date via industrial and research projects around the world. Chapter 4 presents the results of the preliminary analysis of hydrogen storage performance in subsurface conditions representative of depleted gas fields in the U.S. Midwest region to illustrate the performance assessment framework developed. Chapter 5 presents a comparison of fundamental hydrogen dynamics in the subsurface against traditional or more familiar CO_2 and natural gas storage processes. Chapter 6 enumerates high-level recommendations on primary technical, economic, and social considerations to facilitate successful and sustainable commercial deployment of potential UHS projects for policy makers, gas field owners/ operators and energy providers interested in exploring the hydrogen-power nexus.

2.0 Underground Hydrogen Storage Fundamentals

2.1. Engineering Hydrogen Storage in the Subsurface

UHS is considered analogous to underground natural gas storage operations that have been successfully implemented for over a century in salt caverns, depleted reservoirs, and aquifers. UHS is not a novel concept and has been demonstrated on a commercial scale since the 1970s in the world and since the 1980s in the United States.

A typical UHS site aims to provide storage capacity to balance seasonal supply and demand fluctuations and meet peak demand to stabilize the power grid. UHS can utilize naturally occurring porous media or engineered structures for viable large-scale and seasonal energy storage capability. Development of subsurface storage facilities is critical to ensure sustainability and resilience of the planned clean hydrogen economy to meet the nation's decarbonization goals.

To satisfy required storage capacity and sufficient injectivity for acceptable well operating rates, the injection target for UHS needs to be a cavern or a thick, porous, and permeable formation. The reservoir needs to be overlain by a continuous and extremely low permeability caprock to ensure storage integrity and prevent the injected hydrogen from migrating outside the intended storage unit. The hydrogen would be injected for temporary storage (unlike CO_2, which needs to be permanently sequestered) and produced back on demand. The rate at which the well can withdraw gases to meet the user demand is called its deliverability and is one of the performance metrics of an underground reservoir. This cycling operation of injection and withdrawal is analogous to underground natural gas storage operations. Cushion gas is employed to ensure sufficient pressure maintenance and adequate withdrawal rates, which factors into the subsurface storage costs. Different storage options require different amounts of cushion gas as discussed in Section 2.2. Salt caverns require minimal cushion gas, while residual natural gas in depleted gas reservoirs can contribute to the cushion gas requirements.

Infrastructure includes compressors and pipelines to transport hydrogen and wells to inject and produce hydrogen on demand. It is expected that UHS in depleted hydrocarbon fields can potentially leverage existing infrastructure, making these systems easier to develop, operate, and maintain.

2.2. Options for Hydrogen Storage in Subsurface Geological Structures

The most common systems for UHS include salt caverns, depleted oil or gas reservoirs, and saline aquifers. There are also other storage systems, such as engineered hard rock caverns, abandoned surface coal mines, and coal bed storage. Figure 2-1 presents the locations of the primary hydrogen storage play fairways in the United States. Suitable storage systems are available for most existing hydrogen production facilities with sufficient potential to support expansion to the envisioned hydrogen economy. Storage fairways include both sedimentary basins and hard rock terrains. Within the sedimentary basins are salt deposits, depleted oil & gas reservoirs, and saline aquifers. Theoretical hydrogen storage resources within the sedimentary basins far exceeds probable storage needs, but sedimentary basins are not available everywhere. Where suitable hard rock terrains are available, further characterization is needed to understand potential storage volumes. Table 2-1 summarizes the geological, technical, operational, and economic aspects of the common subsurface storage options.

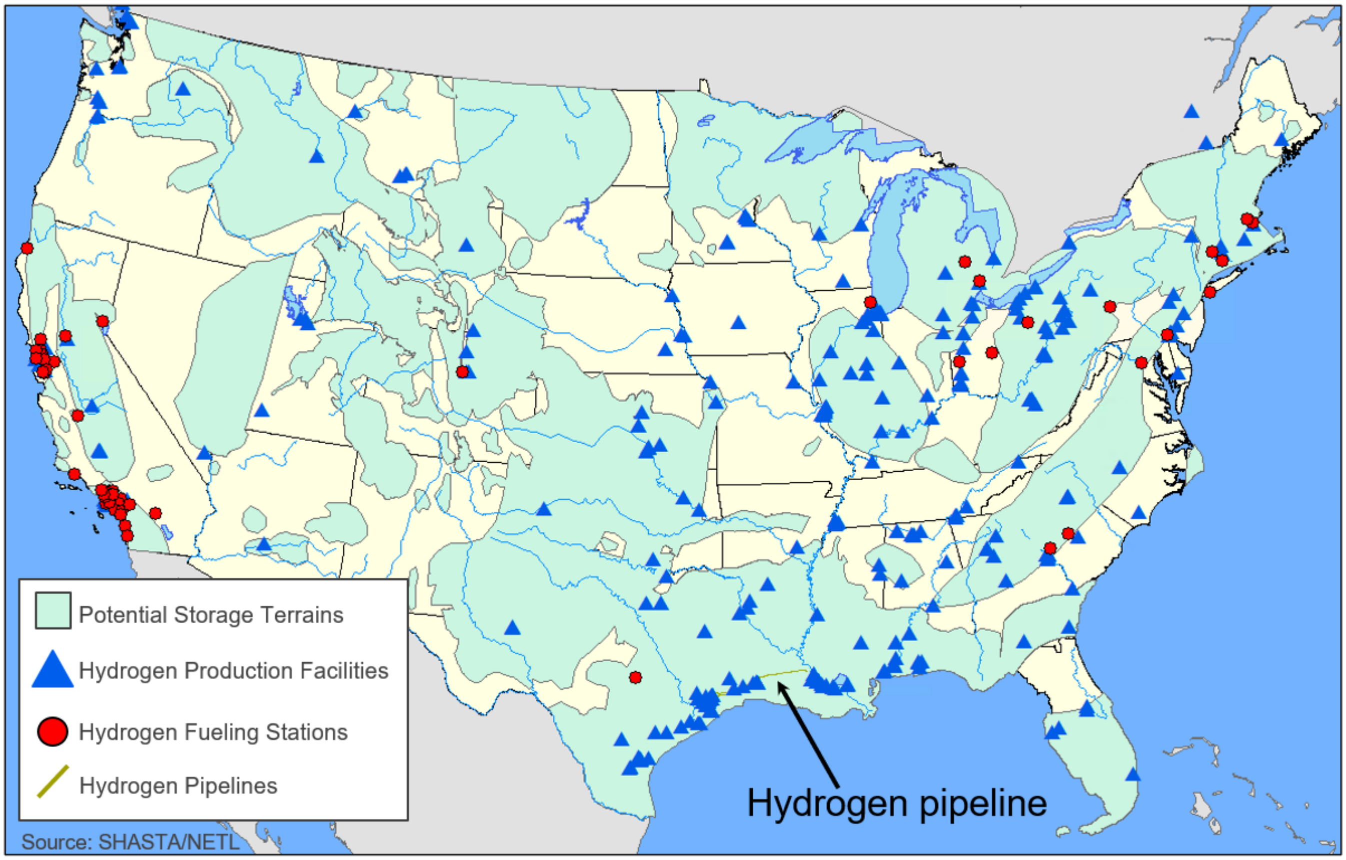

Figure 2-1: Locations of potential hydrogen storage systems in the United States and distance to existing hydrogen production and distribution infrastructure. Storage systems covered include depleted reservoirs, saline aquifers, salt caverns, and hard rock caverns.

Selected Technical Considerations of UHS: All mature technologies with stable and secure gas storage operations (H_2 or analogs as indicated) successfully demonstrated at scale. Depleted reservoirs are available throughout the United States, are well characterized, and have substantial storage capacity. This study focuses on depleted gas reservoirs, which are geologically and economically attractive early candidates for large-scale hydrogen storage, while avoiding the challenges associated with depleted oil reservoirs (e.g., hydrogen interactions with residual oil). However, the technical viability of hydrogen storage in these systems is relatively less developed than in salt caverns. Current information is limited due to few existing operations, and hence requires addressing fundamental understanding of the dynamics.

Selected Economic Considerations of UHS: Capital costs for UHS are comprised of equipment for compression and pipelines to transport hydrogen into and out of the site, wells, and cushion gas. Additional site development costs include mining for engineered systems (i.e., cavern storage and characterization for saline aquifers). Lord et al. (2014) found that depleted oil or gas reservoirs are most cost-effective upon conducting a detailed cost comparison between various geologic UHS targets. The results of their analysis are summarized in Figure 2-2.

Table 2-1: Summary of geological, technical, operational, and economic aspects of subsurface hydrogen storage options.

		Salt Caverns	Hard Rock Caverns	Depleted oil and gas fields	Saline aquifers	Coal Bed Storage
General	**Advantages**	Relatively little cushion gas needed	Rapid cycling	Depleted fields are abundant	Saline aquifers are abundant	
	Disadvantages	High up front cost	Relatively small; likely need multiple caverns	Large cushion gas requirement	Exploration and apprasal needed; high cushion gas requirement	
Geological characteristics	**Advantages**	Proven hydrogen storage option; salt depositsare common globally; rapid cycling; ductile salt heals microfractures	Geomechanically stable; low cavern wall permeability; available outside sedimentary basins	Well understood geology	Well understood geology; lower seal integrity risk from existing penetrations	Adsorption may provide significant storage volume
	Disadvantages	Salt is geomechanically unstable	Subsurface characterization may be difficult	Potential for viscous fingering; interactions with residual hydrocarbons; seal integrity	Lack of existing geological characterization	Unknown behavior in subsurface; highly sensitive to stress state
Infrastructure	**Advantages**	Only 1 well needed for construction and operation	Only 1 well needed for injection/withdrawal	May be able to recycle existing infrastructure	Tailored infrastructure build-out	May be able to recycle existing infrastructure
	Disadvantages	May require pipelines for leaching water		Existing seal/reservoir penetrations add containment risk; may require multiple wells	No existing infrastructure; may require multiple wells	Existing seal/reservoir penetrations add containment risk; may require multiple wells
Costs		Moderate	High	Low	Low	Unknown
Storage Capacity Range		Low to Moderate	Low	Moderate to High	High	High
Experience with Storage		N_2, CH_4, CO_2, H_2	CH_4	CO_2, CH_4	CO_2, CH_4, town gas	CH_4

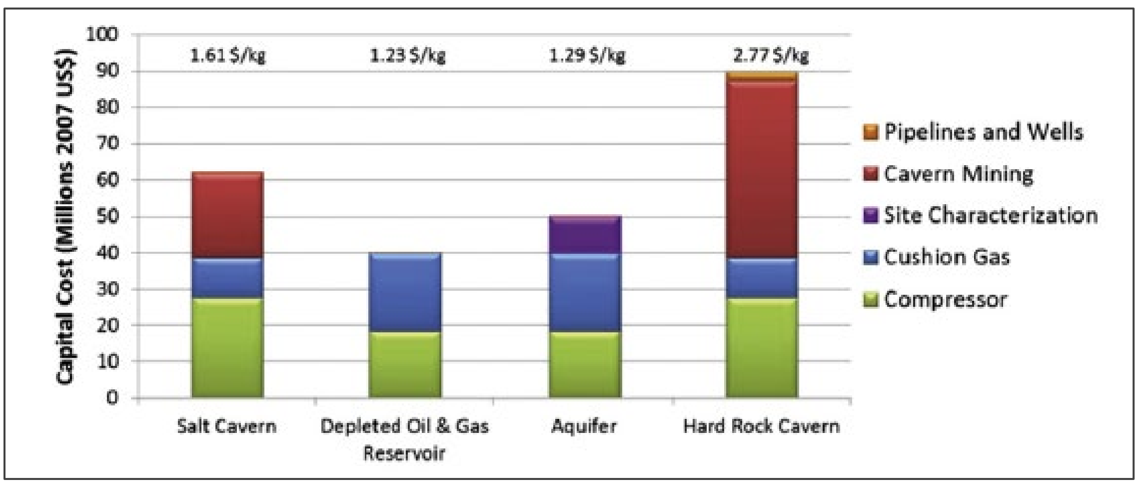

Figure 2-2: Comparison of capital costs between different storage systems (Lord et al., 2014).

Discussion on the advantages, challenges, and operations for each of these geologic storage systems is presented below.

2.2.1. Salt Caverns

Advantages: Salt caverns are the only consistently successful hydrogen storage mode implemented to date (Malachowska et al., 2022; Table 2-2) and have been widely implemented for storage of other gases, such as methane and natural gas.

Table 2-2: Existing salt cavern hydrogen storage operations (Adapted from Malachowska et al., 2022).

	Teeside (UK)	Clemens (US)	Moss Bluff (US)	Spindletop (US)
Operator	Sabic Petroleum	ConocoPhilips	Praxair	Air Liquide
H_2 end use	Power generation & transportation	Petrochemical & industrial	Petrochemical	Petrochemical
Commissioned (year)	1972	1983	2007	2017
Volume (m^3)/possible working gas capacity (10^3 t H_2)	210,000 / 0.83	580,000 / 2.56	566,000/ 3.72	906,000/ Information not available
Average depth (m)	365	1,000	1,200	1,340
Pressure range (bar)	56	70-137	55-152	68-202

Salt caverns are a favorable storage option, as they are relatively inexpensive and simple to construct via dissolution mining, requiring only a single wellbore and associated surface facilities. Once caverns are constructed, cushion gas is necessary, but less is needed than for other reservoir types; only about 30% of the reservoir volume is required, whereas depleted oil and gas reservoirs may require 50% cushion gas or more (Papadias & Ahluwalia, 2021; Malachowska et al., 2022). Salt also has extremely low permeability, reducing the risk of hydrogen loss via migration out of the reservoir. Because evaporites are viscoplastic (meaning they move and deform under their own weight), they are able to “self heal” when microfractures form, providing better assurance of seal integrity and mechanical stability (Sainz-Garcia et al., 2017).

Challenges: The geomechanical stability of salt may be a drawback for salt cavern storage, leading to the formation of microcracks and spalling of the cavern walls, decreasing the strength of the cavern, and increasing permeability and associated losses. Another drawback is the up-front cost of construction, which may be significant if leaching water sources and disposal locations are far from the cavern location (Malachowska et al., 2022).

Operations: Hydrogen has been successfully stored in salt caverns since 1972, and use of caverns continues to date (Tarkowski, 2019). The economics of salt cavern storage are generally strong. Retaining a minimum cavern pressure via cushion gas is crucial to safely operating salt storage caverns, and required cushion gas accounts for 20-30% of cavern volume (Wang et al., 2020; Papadias & Ahluwalia, 2021). Filling-depletion cycles must be planned carefully in order to avoid damaging changes in stress state in the wall rock of the cavern, but caverns may be cycled more frequently than porous storage alternatives (Tarkowski, 2019). The scale and impact of these variables will change depending on the geomechanical setting of the cavern.

2.2.2. Hard Rock Caverns

Advantages: Hard rock caverns may be an effective storage option where sedimentary basins are not available and have been piloted for storage of natural gas (Papadias & Ahluwalia, 2021). In some geologic settings, unfractured crystalline rock may be available and would provide attractive characteristics (e.g., porosities >0.5% and sub-nanodarcy permeability [Lemieux et al., 2020]). Where crystalline rocks are fractured, caverns with engineered linings may be employed. Lined caverns may also be an option in sedimentary basins lacking both salt and acceptable porous formations.

Challenges: Capital costs for engineering and excavating caverns in crystalline rock are likely extremely high and are likely higher than for salt caverns. Hard rock caverns are also likely to be smaller than salt caverns (Papadias & Ahluwalia, 2021). Detailed subsurface geological characterization is critical to avoiding lithologies that may induce weakness in the cavern walls (Glamheden & Curtis, 2006). While hard rock caverns, particularly lined caverns, are not subject to the same degree of microfracture risk as salt caverns, care must still be taken to operate these caverns within acceptable geomechanical limits.

Operations: Hard rock caverns have not been utilized for hydrogen storage, but experience from natural gas storage may provide insight into operations. While modeling of geomechanical stress/strain prior to cavern construction is valuable, real-time monitoring of stress/strain relationships throughout the storage and production cycle will be key to safe, long-term operations (Glamheden & Curtis, 2006).

2.2.3. Depleted Oil and Gas Reservoirs

Depleted Sandstone Reservoirs

Advantages: Depleted sandstone reservoirs are abundant throughout the United States and the world, are individually and collectively well understood, and in many cases, offer relatively uniform reservoir rock. Siliciclastic reservoirs tend to be composed primarily of quartz and feldspar, and so mineralogically should be relatively unreactive with hydrogen. They are often in areas proximal to population centers and pre-existing infrastructure such as pipelines and energy sources and are likely to already have surface and subsurface equipment that allows for injection and withdrawal of gases (Tarkowski, 2019).

Challenges: Reservoir wettability and viscous fingering are two important dynamic processes that present challenges to hydrogen storage in porous media. Wettability impacts due to hydrogen injection and storage is an area of active research. Early research findings from laboratory-based studies on sandstone wettability impacts vary between no impacts to the reservoir wettability (Buscheck et al., 2023) to potential for sandstone reservoirs to become weakly hydrogen wet (Al-Yaseri et al., 2022; Esfandyari et al., 2022). The limited data are strong functions of the experimental methodologies used including the preparation of the rock surfaces and equilibration times.

Viscous fingering provides another avenue for hydrogen loss. Viscous fingering occurs when a highly mobile fluid (such as hydrogen) unevenly displaces a less mobile fluid (such as brine, oil, or natural gas), resulting in mixing of the two fluids or partitioning of the reservoir via the creation of relative permeability barriers (Feldmann et al., 2016). Fingering can be exacerbated by reservoir heterogeneity, such as fracture zones or interbedding of sand and shale.

A third dynamic process, one less understood for hydrogen, is reactivity with the organic constituents of depleted reservoirs, including microbes, kerogen, and residual hydrocarbons. Hydrogen losses to chemical interaction or microbial interaction may be significant in some reservoirs and could even lead to the formation of contaminants, such as hydrogen sulfide.

In areas with multiple reservoir intervals or dense historical drilling, thorough analysis of wellbore integrity for legacy wells must be conducted to confirm seal integrity.

Operations: No hydrogen storage has been implemented in depleted sandstone reservoirs, so operational aspects for this storage type, such as leakage, cushion gas, microbial interactions, and mixing with residual hydrocarbons are not well understood. That said, depleted reservoirs have been extensively used for the storage of natural gas. The use of cushion gas will likely be mandatory in all depleted reservoir storage scenarios. Cushion gas provides some mitigation to the challenges of wettability and fingering discussed above, as well as providing pressure support to expel stored hydrogen at useful rates. Injection cycles may be limited to seasonal cycling or a single injection-withdrawal cycle annually (Tarkowski, 2019).

Depleted Carbonate Reservoirs

Advantages: Depleted carbonate reservoirs may be even more abundant than depleted sandstone reservoirs, and can provide exceptionally high porosity and permeability, often higher than their sandstone counterparts. They offer the same sets of advantages as sandstone reservoirs, except that carbonates are more mineralogically active.

Challenges: Challenges in carbonate reservoirs mirror those in sandstone reservoirs, but early laboratory studies have shown that wettability impacts from hydrogen may be greater in carbonate formations (Zeng, 2022). Additionally, carbonates are generally more chemically active than their siliciclastic counterparts, which may lead to hydrogen losses. For example, Zeng, 2022 have modeled scenarios with 6.5% hydrogen loss to calcite dissolution over six months and 31% losses over a 100-year storage period. Significant uncertainty exists on this topic, and further study of potential interaction between carbonate minerals and stored hydrogen is needed.

Operations: No hydrogen storage has been implemented in depleted carbonate reservoirs, so operational aspects for this storage type, such as leakage, cushion gas, microbial interactions, and mixing with residual hydrocarbons, are not well understood. Because hydrogen may cause calcite dissolution, carbonate reservoirs will need high-resolution, real-time monitoring of geomechanical stability, as well as monitoring for hydrogen escaping the reservoir. Injection cycles may be limited to seasonal cycling or a single injection-withdrawal cycle annually (Tarkowski, 2019).

Depleted Shale Reservoirs

Advantages: Tens of thousands of unconventional shale oil and gas wells are nearing the end of their producing lives. Because mature shale reservoirs are generally well understood, are often in high-infrastructure areas, generally form their own seals, and the up-front cost of drilling has already been spent, depleted shale wells may be attractive storage targets (Singh, 2022; Raza et al., 2023).

Challenges: Further study is needed to understand how the wide variety of shale mineralogies, variable total organic carbon (TOC) content, and thermal maturities impact storage and delivery efficiency. It is also likely that “depleted” wells will have some residual hydrocarbons that may contaminate stored hydrogen. In densely developed reservoirs, wells may be connected via induced hydraulic fractures, making storage integrity difficult to assess. Most or all of the challenges noted for the other depleted reservoirs apply to shale reservoirs.

Operations: No hydrogen storage has been implemented in depleted shale wells, so operational aspects for this storage type such as leakage, cushion gas, microbial interactions, and mixing with residual hydrocarbons are not well understood.

2.2.4. Deep Saline Aquifers

Saline Sandstone and Carbonate Aquifers

Advantages: Geological advantages of saline aquifers mirror those of their depleted sandstone and carbonate counterparts, but saline aquifers may be favorable for several reasons. Saline aquifers are generally larger than their hydrocarbon-bearing counterparts and are more widely distributed, since not all sedimentary basins have the correct conditions for hydrocarbon reservoir development. Additional advantages include lower risk of interactions with residual hydrocarbons, and aquifers that have not been previously used for storage or disposal may also benefit from a lack of existing well penetrations, providing higher confidence in seal integrity.

Challenges: The lack of existing well penetrations that are beneficial for seal integrity is a drawback for reservoir analysis. Lack of well penetrations can make assessing structural and stratigraphic variability difficult and may mean that early petrophysical models of the reservoir have greater uncertainties. Proving that an untested saline aquifer is appropriate for hydrogen storage is likely to require multiple exploration wells, 2D or 3D seismic, and extensive laboratory testing of samples recovered from exploration wells. Resulting up-front costs are likely to be higher than for depleted hydrocarbon reservoirs (Tarkowski, 2019). Alternatively, where saline aquifers have been used for waste storage, existing penetrations may be a risk. Cushion gas needs may also be higher than at depleted reservoirs (Lord et al., 2014). And while most saline aquifers will not suffer drawbacks associated with the presence of hydrocarbons, most sedimentary formations contain at least some organic matter and microbes that may interact with stored hydrogen.

Operations: Pure hydrogen storage has yet to been implemented in saline aquifers, but they are the largest source of natural gas storage currently in operation, and several projects have stored hydrogen-bearing “town gas” (Sainz-Garcia et al., 2017; Tarkowski, 2019). Injection cycles may be limited to seasonal cycling or a single injection-withdrawal cycle annually (Tarkowski, 2019). The economics of storage in saline aquifers appear to be favorable (Lord et al., 2014).

2.2.5. Others

Coal Bed Storage

Advantages: Minimal work has been done to understand the ability of coal seams to store hydrogen. Laboratory analysis indicates that coal may provide storage in both pore spaces and via adsorption (Iglauer et al., 2021), but further work is needed to characterize UHS in coal beds at the field scale.

Challenges: Coals of different ranks and grades have drastically different behaviors in the subsurface and the porosity and permeability of coal is highly sensitive to stress state (Pan et al., 2009).

Operations: No data exist for operating hydrogen storage in coal fields; data from storage of other gases may be misleading due to the variance in coal cleat behavior based on stored gas species (Iglauer et al., 2021).

Naturally Occurring Hydrogen

While the hydrogen storage discussion is focused on ‘manufactured hydrogen’, naturally occurring hydrogen is also present in the subsurface across the world including in the U.S. Natural hydrogen is being actively researched as it is expected to be a significant potential clean hydrogen resource. Key uncertainties being investigated include mapping the resource potential to determine where and how much hydrogen is present and fundamental understanding of these systems to assess how much of this can be economically accessed. Natural hydrogen originates from a variety of geologic processes, the most dominant being subsurface serpentinization, natural water hydrolysis, and primordial molecular hydrogen degassing from the mantle (Epelle, 2022). The resultant hydrogen from these processes tends to migrate upward, where it is likely to be found in seeps near the surface as well as in structural traps in the subsurface. Figure 2-3 shows a comparison of several aspects of natural hydrogen production with UHS.

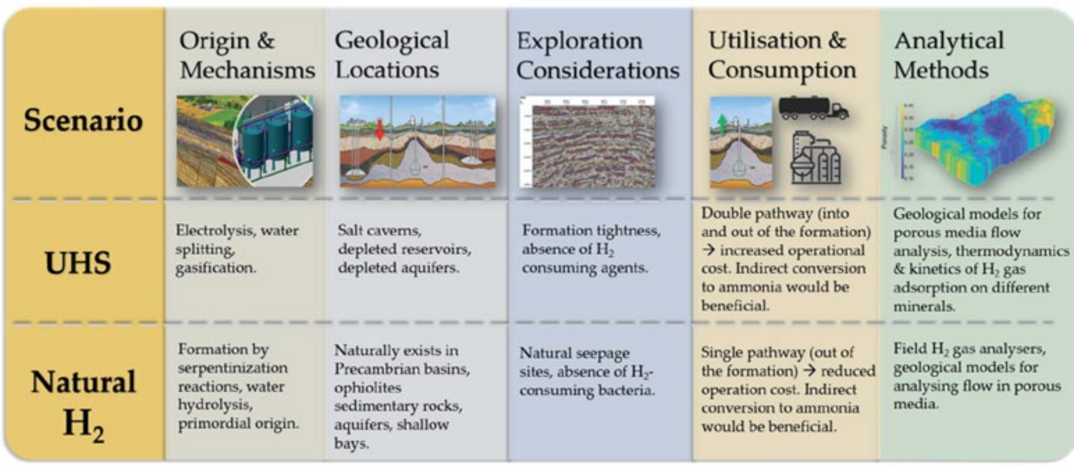

Figure 2-3: Comparison between naturally occurring hydrogen and UHS (Epelle, 2022).

Historically, subsurface resource exploration has been focused almost exclusively on hydrocarbons, which typically occur in areas where microbes and other subsurface processes are likely to consume free hydrogen. Because of this hydrocarbon focus, most global hydrogen discoveries have been accidental (Zgonnik, 2020; Ellis, 2023). The largest recorded natural hydrogen flow was recorded in a well at the Udachnaya kimberlite pipe in Russia, flowing approximately 3.5 million cubic feet per day, which would provide the energy equivalent of just over 1 million cubic feet of natural gas per day, similar to a marginal natural gas well. This rate was sustained for less than three days before the well watered out and was shut in (Zgonnik, 2020). That said, efforts to develop hydrogen specific exploration strategies are in progress. In recent years, academics, geological surveys, and private exploration ventures have begun to target natural hydrogen accumulations specifically and, as a result, estimations of resource availability are increasing. United States Geological Survey natural hydrogen expert Geoff Ellis estimates that global natural hydrogen reserves could be as high as 10 million megatons. Assuming a global hydrogen demand of 500 megatons per year by 2050, this is enough natural hydrogen to meet global demand for hundreds of years, even assuming relatively low recovery factors (Ohnsman, 2023).

Because free hydrogen is typically associated with mafic igneous and metamorphic rocks, much of the resource may be too deep (in the case of metamorphic core complexes) or too far offshore (in the case of mid ocean ridge basalt serpentinization) to be economically viable, so exploration is currently focused on accumulations within onshore igneous or sedimentary reservoirs overlying failed rift systems and igneous intrusions. A key example of this new exploration is HyTerra’s acquisition of drilling rights and working interests in Kansas and Nebraska along the Midcontinent Rift System, a 1200 mile long Precambrian failed rift system (Figure 2-4) where wells have historically encountered hydrogen shows (Hinze & Chandler, 2020; HyTerra, 2023). While the resource potential offered by natural hydrogen reservoirs still requires further investigation, these research and exploration efforts are valuable to inform technical considerations and risks associated with storage integrity for UHS in general.

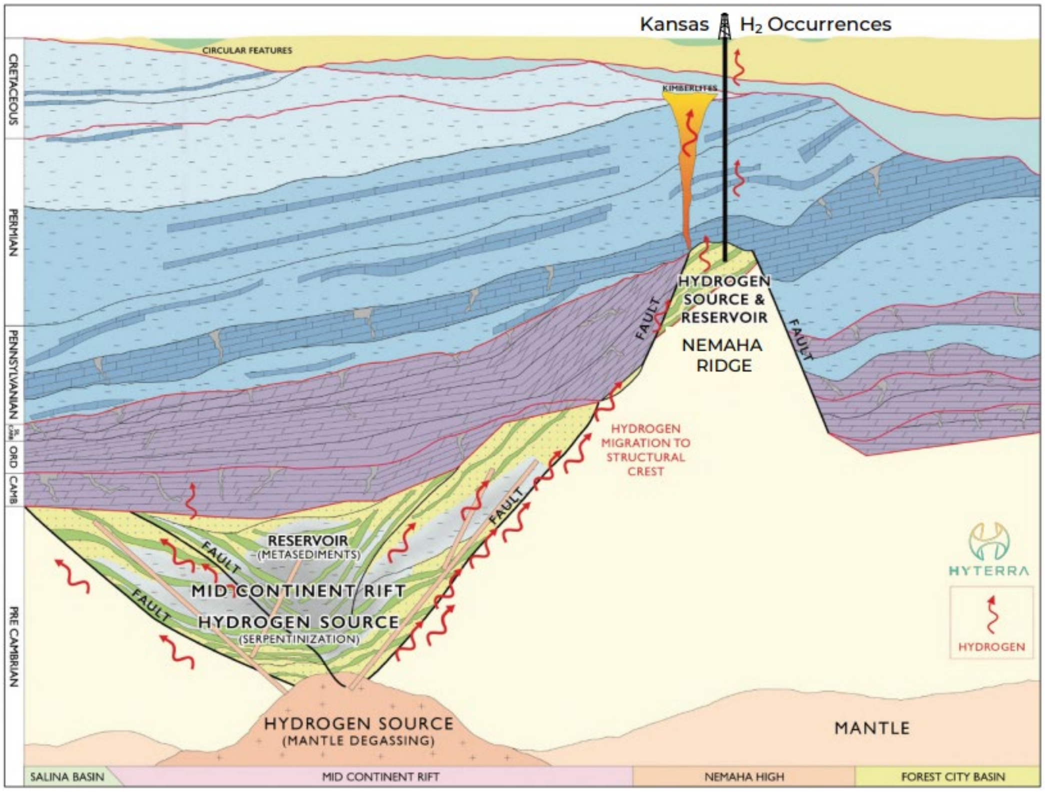

Figure 2-4: Schematic play diagram detailing the hydrogen source, migration pathway, and reservoir system associated with the Midcontinent Rift System, from HyTerra 2023 investor relations slidepack. (HyTerra, 2023)

2.3. Key Considerations and Risks for UHS Operations

While the concept of hydrogen storage is not new, impacts of hydrogen to reservoirs with respect to leakage risks and ensuring storage integrity and deliverability are areas of active research, and field-scale behavior is not well understood for all the subsurface systems. The physical and chemical processes involved in assessing the feasibility of UHS need to be systematically characterized, as they are complicated by formation fluid compositions, minerology, and reservoir in-situ conditions. Molecular hydrogen has unique thermodynamic properties and is highly reactive as compared to other gaseous substances (e.g., carbon dioxide and methane). The critical processes associated with UHS can be grouped into four primary categories: Hydrogeology, Geochemistry, Microbial Activity, and Geomechanics (see Figure 2-5). Each of these categories has associated operational risks, and many of the risks are interconnected. These risks will be addressed in the following section, with relevant comparisons to analogous gases for fundamental technical basis of understanding operational impacts.

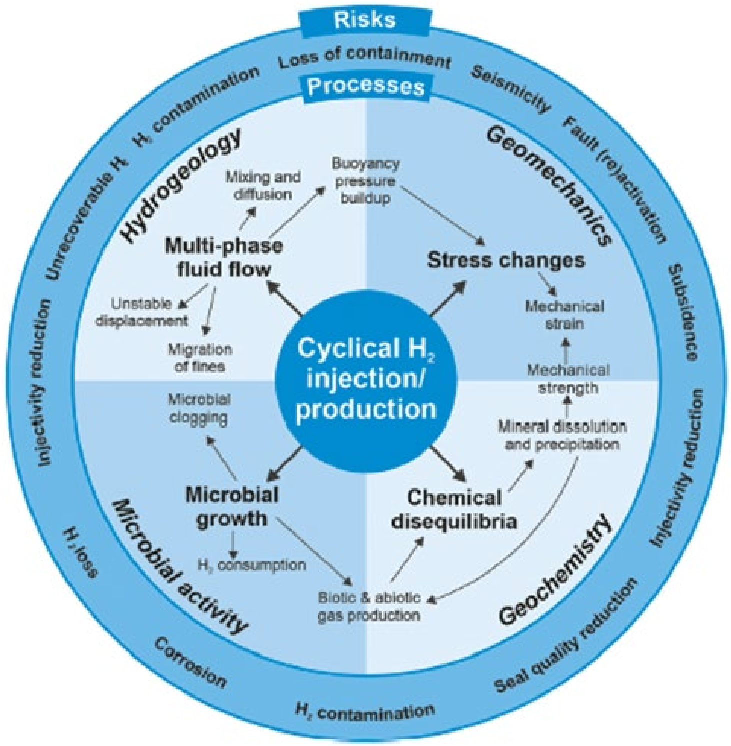

Figure 2-5: Critical processes and risks associated with UHS (Heinemann et al., 2021).

2.3.1. Hydrogeology

The thermodynamic behavior of molecular hydrogen presents many challenges that need to be investigated for underground storage. Hydrogen is handled and stored as a gas in the subsurface in comparison to surface storage applications, where it is usually maintained in the liquid phase through strict temperature and pressure control. Figure 2-6 shows the phase diagram of hydrogen with extremely low critical pressure and temperature (13 bar and 33K, respectively), meaning only the gas phase is accessible at reservoir conditions. A detailed examination of the following considerations for the reservoir dynamics involved with UHS is given in Buscheck et al., 2023.

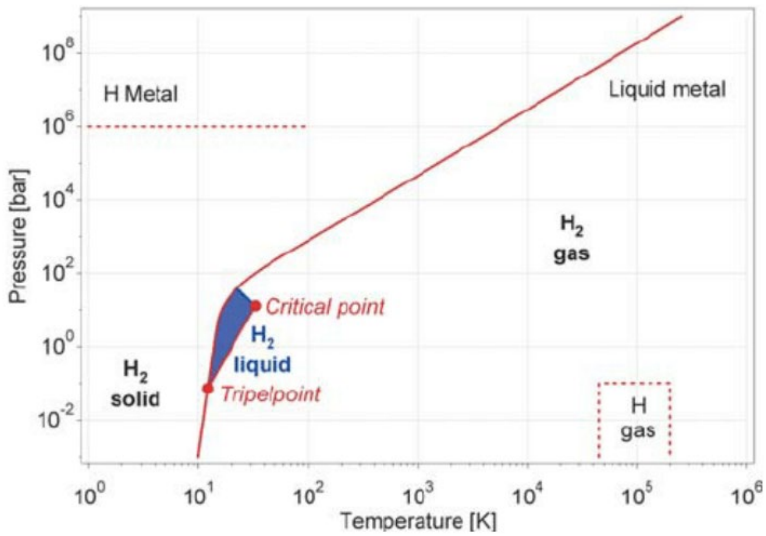

Figure 2-6: Phase diagram of pure hydrogen (Zuttel, 2004).

The low density of hydrogen in the gaseous phase will limit the amount capable of being kept in any given storage volume. Moreover, the amount of gravitational differentiation present within a target formation will be significant. The hydrogen will preferentially flow upward toward the base of the caprock. While this separation could be beneficial in terms of separating working hydrogen from in-situ fluids, controlling the migration of highly buoyant hydrogen may present challenges. The viscosity of hydrogen is also low, which can lead to viscous fingering as injected hydrogen flows into higher viscosity reservoir fluids. Figure 2-7 shows an example of viscous fingering in a gas-water system. The effect is more pronounced the greater the difference in viscosity between injected and in-situ fluids.

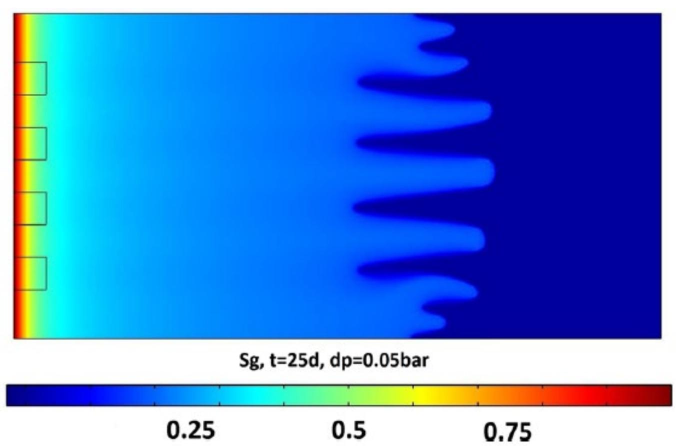

Figure 2-7: Example showing viscous fingering in a gas-water system (Feldmann et al., 2016).

The higher diffusivity and solubility of hydrogen also have a large impact on the storage efficiency of UHS operations, as hydrogen will tend to spread out into the target storage formation. In aqueous systems, the dissolution of hydrogen in formation brine will cause some of the injectate to become unrecoverable. In depleted natural gas reservoirs, the high diffusivity will cause a high degree of mixing, reducing the purity of extracted hydrogen and increasing the potential for asset loss. This mixing will have an impact on the thermophysical properties of the working gas, an important consideration in forecasting simulations and economic analyses. Hassanpouryouzband et al. (2020) developed an Excel-based tool for modeling this composition-dependent property evolution in hydrogen-containing streams.

Consideration of wettability impacts will be critical in forecasting analyses, as the wettability of reservoir rock and caprock can significantly impact fluid flow through porous rock and storage integrity. Characterization of the impacts of wettability on various mineralogies is an area of active research with limited modeling and laboratory-based studies helping establish early understanding of the efficiency of hydrogen recovery.

The primary risks that need to be characterized when evaluating reservoirs for hydrogen storage involve asset loss and storage integrity. Hydrogen's high diffusivity and low viscosity can cause significant residual trapping. Jha et al. (2021) suggested that residual hydrogen saturation in aqueous storage formations could be as high as 41%. This residual trapping can be significantly mitigated through the use of cushion gas. Systems with proven caprock integrity for natural gas storage need to be evaluated for hydrogen to ensure structural/stratigraphic trapping. Wellbore integrity impacts are unknown as there is minimal data available on hydrogen diffusion through cement (Goodman Hanson et al., 2022).

2.3.2. Geochemistry

Geochemical processes are important in UHS, as hydrogen is a highly reactive substance that can chemically interact with most materials it contacts. Geochemical reactions with the minerals and fluids in the subsurface and wellbore materials need to be considered to ensure system integrity and deliverability. Mineral dissolution and precipitation potentially cause changes to the porosity and permeability of both the target formation and associated caprock, depending on the composition of the rocks. Impacts can vary from being advantageous (i.e., enhancing the storage volume through the creation of additional porosity in the storage formation) to disadvantageous (i.e., lost porosity/cementation in the target zone and reduced caprock integrity with a higher potential for leakage). Hydrogen can also react with clays in the caprock, causing swelling and improving caprock integrity (Shi et al., 2020).

Hydrogen will also react with materials in the wellbore. Models have shown that hydrogen reactivity with cement does not appear to cause significant changes in cement porosity (Goodman Hanson et al., 2022). However, reactions with the steel casing and/or elastomers used in the construction of packers are important considerations. In the steel casing, the primary concern is hydrogen embrittlement. When hydrogen is highly concentrated, it can diffuse into the metal causing cracking and failure, which is also a concern in pipelines at the surface. The reaction of hydrogen with wellbore seals and packers is a known issue from the natural gas storage industry. As a result, many hydrogen-resistant sealing elements have already been developed. Further testing is necessary to determine their effectiveness in UHS applications (Goodman Hanson et al., 2022).

Adsorption of hydrogen within the target formation is another important consideration. This chemical process could impact recovery efficiency and may also play a key role in enabling particular types of hydrogen storage such as abandoned coal mines. Hydrogen adsorption has been studied in various types of clays and coals, as shown in Figure 2-8. Hydrogen appears slightly more adsorptive in clays than coals, with both anthracitic and bituminous coals having fairly consistent adsorption capacities. Iglauer et al. (2021) examined the adsorption of both H_2 and CO_2 in sub-bituminous coals (Figure 2-9). The adsorption capacity of hydrogen was consistent with other coals but is significantly less than that of

CO_2 in the same media. It is clear that adsorption could have some impact on recovery efficiency, particularly in clay-containing formations. Further analysis is necessary to determine whether hydrogen adsorption is effective in shales to be utilized for UHS.

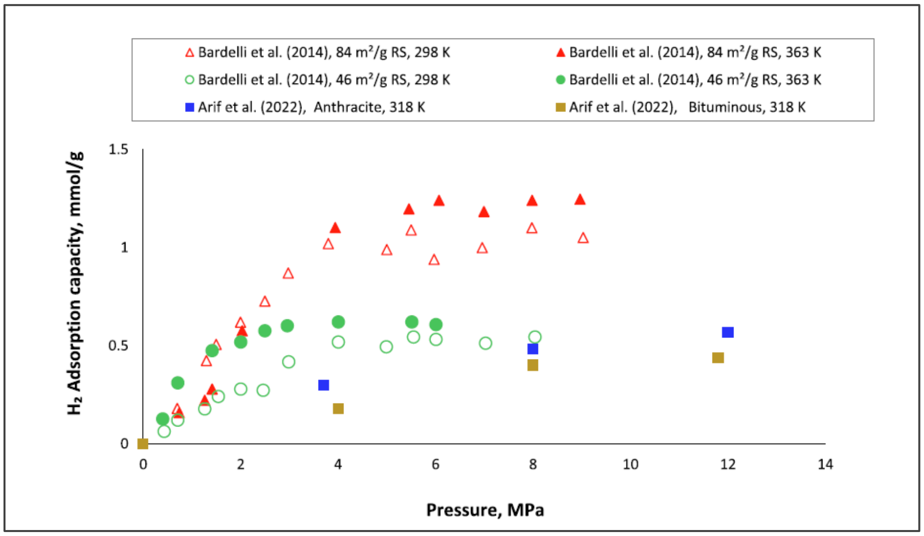

Figure 2-8: Hydrogen adsorption capacity of various clays (red/green) and coals (blue/brown) (Raza, 2022). The pressure range displayed (0-14 MPa) corresponds to 0-2030 psia.

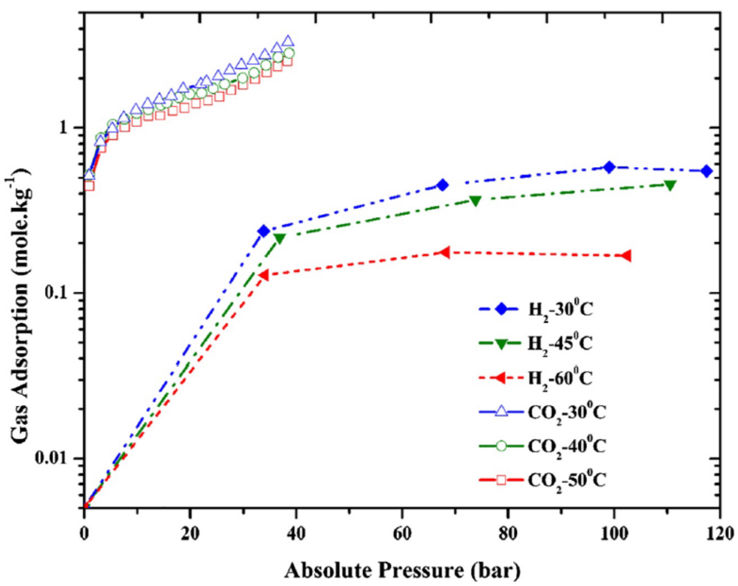

Figure 2-9: Carbon dioxide and hydrogen adsorption on sub-bituminous coals (Iglauer, 2021). The pressures displayed in this figure (0-120 bar) correspond to 0-1740 psia.

2.3.3. Microbial Activity

Microbiological interactions are another potentially important factor in UHS that impact both recovery efficiency and storage integrity. The primary reactions of interest are delineated in Table 2-3. Methanogenesis, in particular, has been shown to significantly reduce recovery efficiency in hydrogen storage applications (RAG, 2017). The hydrogen sulfide-forming reactions are important to consider, as hydrogen sulfide is a toxic gas that is also highly corrosive. This reaction could lead to steel corrosion, both in the wellbore and in surface transportation infrastructure. Microbial reactions could also cause the pH drop of formation fluids (via acetogenesis) and could potentially impact the porosity and permeability of storage formations (i.e., porosity improvement via mineral dissolution and/or porosity reduction via microbe-induced plugging). These microbiological interactions thus result in depletion and/or contamination/ souring of stored hydrogen that is highly undesirable. The potential of using the presence of products of these reactions in overlying formations as a tracer for hydrogen leakage has also been noted (Dopffel, 2021). To date, most testing on the influence of microbiological interactions with hydrogen has been at bench-scale. The critical gap in fundamental insights is accentuated by sparsity of relevant field data. A well-described investigation from town gas storage at a site in the Czech Republic provides insights into potential impacts where approximately half of the hydrogen stored was reported lost due to microbial activity (Smigáň et al., 1990). Understanding the impact of these reactions on field-scale UHS is critical for commercial deployment (Goodman Hanson et al., 2022).

Table 2-3: Primary microbial reactions that impact hydrogen storage (Dopffel, 2021).

Table 1 – Overview of the major microbial hydrogen-consuming processes, listed in their expected importance for hydrogen underground storage.

Hydrogen-consuming process	Reaction	Free Energy $\Delta G^{0'}$ (kJ*mol^{-1} H_2)	Important parameters for the process to occur
Methanogenesis	$\frac{1}{4} HCO_3^- + H_2 + \frac{1}{4} H^+ \rightarrow \frac{1}{4} CH_4 + \frac{3}{4} H_2O$	−33.9	Often at high temperatures CO_2/Carbonate content Less active at pH > 7 Low redox potential
Acetogenesis	$\frac{1}{2} HCO_3^- + H_2 + \frac{1}{4} H^+ \rightarrow \frac{1}{4} CH_3COO^- + 2H_2O$	−26.1	CO_2/Carbonate content Higher activity at pH < 7
Sulphate reduction	$\frac{1}{2} SO_4^{2-} + H_2 + \frac{1}{2} H^+ \rightarrow \frac{1}{2} HS^- + H_2O$	−38.0	Sulphate/sulfidic minerals content
Iron reduction	$2\ FeOOH + H_2 + 4\ H^+ \rightarrow 2\ Fe^{2+} + 4H_2O$	−228.3	Iron mineral content
Denitrification	$2/5\ NO_3^- + H_2 + 2/5\ H^+ \rightarrow 1/5\ N_2 + 1\ 1/5 H_2O$	−240.1	Nitrate content in water
Sulfur reduction	$H_2 + S \rightarrow H_2S$	−33.1	Sulfur content
Aerobic H_2 oxidation	$H_2 + \frac{1}{2} O_2 \rightarrow H_2O$	−237	Oxygen ingress in system

2.3.4. Geomechanics

Heinemann et al. (2021) provides a good discussion of the geomechanical considerations of UHS in porous media, including stress changes due to injectate that lead to potential for induced seismicity, fault reactivation, and subsidence. It is unclear whether the injection of hydrogen specifically presents additional challenges over other injected material. The structural stability of engineered storage formations (e.g., salt caverns) has been successfully managed by appropriate operational design.

3.0 Industrial Experience with Underground Gas Storage

This chapter summarizes UHS experience to date via industrial and research projects around the world. It highlights extensive historical analogous industrial natural gas storage experience that can be leveraged for UHS in depleted gas reservoirs, which is in the early stages of development. As detailed in Chapter 2, underground gas storage has been implemented extensively around the globe, primarily in three types of reservoirs: depleted hydrocarbon reservoirs, saline aquifers, and salt caverns. The vast majority of working storage is for natural gas. A minority of storage is for town gas, hydrogen, nitrogen, and other useful gases (Goodman Hanson et al., 2022; Table 2-1). A total of 661 natural gas storage facilities were in operation worldwide at the end of 2019, with a combined working gas capacity of 422 billion m^3 with two thirds of the facilities concentrated in North America (Cedigaz, 2020). In comparison, there are only four working hydrogen storage facilities, with a combined capacity of less than 2.3 million m^3 (Malachowska et al., 2022).

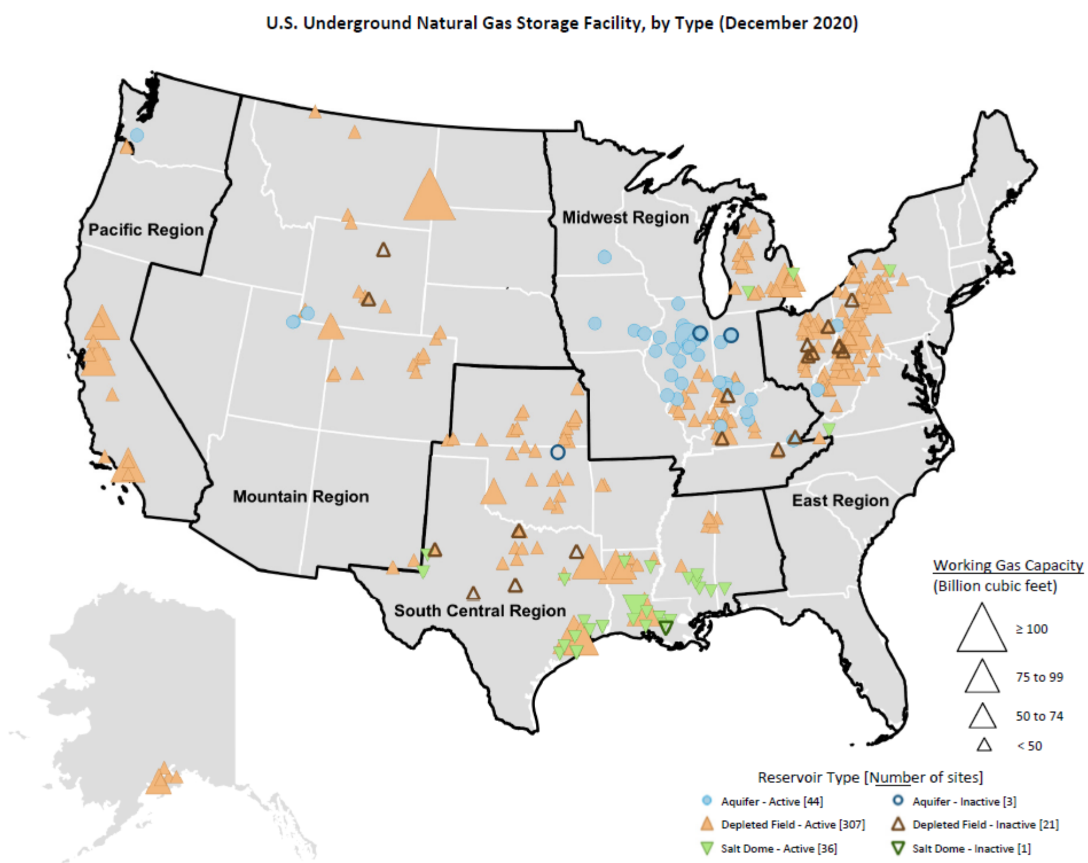

Figure 3-1: Geographical distribution of underground natural gas storage by type in the United States, as of 2015 (EIA, 2022, https://www.eia.gov/naturalgas/ngqs/images/storage_2020.png).

Experience in salt caverns: As stated in Chapter 2, salt caverns are the only consistently successful hydrogen storage mode implemented to date; several of which make up a subset of the 36 gas storage caverns in operation in the United States (Figure 3-1). Salt caverns have been used for gas storage since the 1960s and have proven to be both effective at containing gases without leakage, and affordable to construct and operate relative to other storage options (Firme et al., 2019; Malachowska et al., 2022). Salt cavern construction via leaching, and operation in clean, diapiric salt are both relatively well understood, although continued work is needed to understand the best construction practices and operating envelope of caverns in bedded or impure salt.

Salt cavern storage does carry some risk. Diapiric salt domes tend to interact with surrounding sediment as they form (Giles & Lawton, 2002), causing the edges of the dome to become intimately interfingered with or mixed with non-evaporitic sediments. This mixing degrades the behavior of the salt under stress, causing loss of structural integrity and the possibility of failure, as in the Bayou Corne storage cavern collapse, which both destroyed the cavern and created a significant sinkhole at the surface. Collapses of this type can be avoided by maintaining substantial offset (>100 m) from the edges of a salt dome or deposit, and by carefully monitoring the size and shape of the cavern during operations (Firme et al., 2019). When multiple caverns are to be constructed in a single salt body, care must be taken to distribute them safely, with cavern size and distribution a function of the mechanical characteristics of individual salt bodies (Slizowski et al., 2017).

Experience in rock caverns: Rock caverns have not yet been implemented for UHS, so operational understanding to date is via modeling or analogy to natural gas storage and implementation for natural gas storage, with most of the existing knowhow from research focused on the Skallen lined rock cavern in Sweden. Pre-construction modeling of geobody stress and deformation responses as Skallen matched observed deformation relatively well (although the observed deformation was less than modeled deformation), but stress & deformation monitoring during and after construction will be critical to cavern integrity and safety, as different geological settings may display different deformation magnitudes (Glamheden & Curtis, 2006). Strain during cycling of the cavern has been within the design envelope, and no leakage through the steel lining has been observed. The project has met deliverability needs and may be capable of exceeding design expectations, proving that lined rock caverns can successfully support high pressure, high frequency injection and production cycles (Tenborg et al., 2014).

Unlined rock caverns can also be employed, but because they may be constructed in rock with fractures and microporosity that result in minor (nanodarcy) permeability, they must typically be paired with a ‘water curtain’ system. The water curtain consists of multiple horizontal tunnels or wellbores drilled around and above the cavern, and water is pumped continuously through the tunnels in order to fill porosity around the cavern with high-pressure water, thereby preventing gases from migrating away from the cavern. Thus, this system is quite expensive, and the water curtain operations could create potential issues such as water leaking into the cavern, causing loss of storage area, requiring pumping, and mineral or microbial growth within the cavern (Lord, 2009; Crotogino, 2022).

Experience in depleted reservoirs: Although no hydrogen storage has been implemented in depleted reservoirs, natural gas storage in depleted reservoirs has an even longer history than salt caverns. Storage in depleted reservoirs was implemented as early as 1915, and depleted reservoirs now make up 80% of global underground gas storage, including 307 active facilities in the United States (Figure 3-1; Tarkowski 2019).

The use of cushion gas will be critical to successful, economic operation of UHS in depleted reservoirs, as cushion gas provides a number of benefits:

- Cushion gases tend to be significantly cheaper than hydrogen.
- Higher hydrogen injection rates, as hydrogen displaces the compressible cushion gas instead of displacing incompressible water.
- Improved hydrogen production rate at the end of a production cycle, again due to the compressibility of cushion gas.
- Decreased loss of hydrogen due to viscous fingering, as the cushion gas interacts with reservoir liquids instead of hydrogen interacting with those liquids.

Modeling also indicates that with long duration (annual) injection-withdrawal cycles, depleted reservoirs operated with a non-hydrogen cushion gas (CO_2 or N_2) can deliver similar purities of hydrogen across repeated cycles (Yousefi et al., 2021).

Experience in saline aquifers: Industrial experience with saline aquifer storage of natural gas is also quite extensive, with 47 active aquifer storage sites in the United States (Figure 3-1). Although nominally similar in setup and geographic setting to depleted natural gas reservoirs, appraisal, construction, and operation of aquifer storage carries its own set of challenges as these systems will typically lack the pre-existing geoscience, production and pressure datasets that come with the re-use of a petroleum reservoir. This makes the detailed site characterization and testing crucial to determine relevant optimal operational performance drivers. A key example of the operational performance of these geologic systems is related to pressure management. In reservoirs with multiple injection/production wells, appropriate well spacing and operating procedures (both informed by the geology of the structure and planned storage and deliverability rates) are key to establishing a reservoir pressure regime that minimizes detrimental pressure interference (Harati et al., 2023).

Another example is reservoir leakage, which has caused gas losses at the Leroy natural gas storage facility in Wyoming. This aquifer storage facility began losing gas and brine due to fault dilation caused by elevated operating pressures. Lacking prior geomechanical data, operators were able to limit leakage by reducing operating pressures, and later 3D reservoir and geomechanical modeling studies were able to positively identify the leakage as fault-related (Chen et al., 2013). Understanding aquifer geomechanics ahead of initial injection, as well as utilizing a full suite of pressure and leakage monitoring systems is critical to ensuring containment in these systems.

Deliverability and Cycling: The cycling frequency is typically determined by the needs of the end use. For example, storage to serve peak demand versus seasonal energy balancing reflects short- versus long-term energy storage end uses and thus have storage durations varying from hours to days. Deliverability is primarily impacted by maximum allowable pressure and maximum storage volume. Caverns (both hard rock and salt) tend to be smaller in volume than reservoirs in porous media, and so tend to be most useful for short-term deliverability. One possible usage may be for electrical ‘peak shaving’, as when a service area experiences a day of particularly high or low temperatures, so the grid requires a ‘peak’ of electricity to account for cooling or heating of residences and other buildings (i.e., Texas’ freeze-related electric grid failure in winter 2021). Porous reservoirs, because of their relatively large volume and the potential for structural and hydrodynamic complications caused by rapid cycling, tend to be better suited to longer cycling periods, like seasonal usage. One example of a seasonal cycle would be strong summer production of solar electricity in high latitudes, allowing for production and storage of green hydrogen to be used during winter, when solar efficiency decreases (Sambo et al., 2022). A schematic illustrating energy cycling in a green hydrogen storage system is shown in Figure 3-2 (Heinemann et al., 2021).

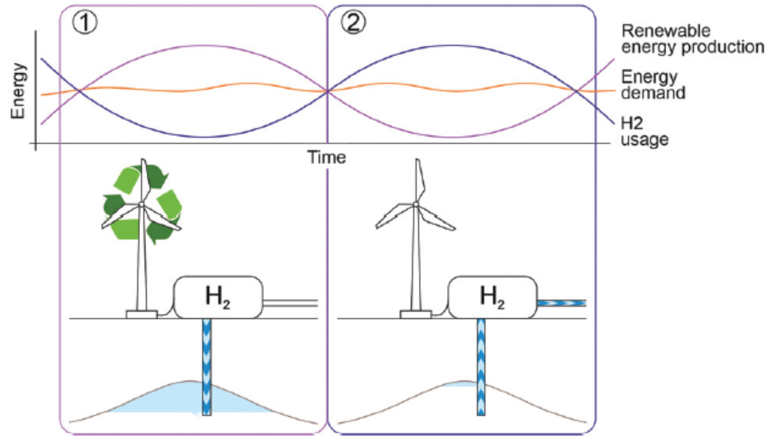

Figure 3-2: Cyclic hydrogen storage in a Green Hydrogen system. Excess hydrogen is stored when energy supply is greater than energy demand, and the stored gas is extracted when the opposite is true (figure from Heinemann et al., 2021).

4.0 Underground Hydrogen Storage Performance in Depleted Gas Reservoirs

Understanding the dynamics and operations of hydrogen storage systems is a necessary first step in planning for the development of large-scale UHS projects. Depleted gas reservoirs and gas storage sites provide a useful analog in this effort. These systems are well-characterized and well-documented with tens of thousands of successfully drilled gas wells in the U.S. Midwest region alone. As discussed earlier, depleted gas reservoirs have proven storage integrity with their in-situ natural gas, making them a natural first target for hydrogen storage systems. Moreover, the logistics of converting depleted petroleum fields into storage fields has already been demonstrated with natural gas.

The current study aims to provide an understanding of the dynamics of hydrogen storage in depleted reservoirs by establishing a preliminary screening performance assessment modeling framework. This framework evaluates key UHS performance metrics discussed in Section 4.2 using analytical models. This is also utilized to successfully compare different storage fluid options in porous formations such as natural gas and CO_2 in similar subsurface conditions. Key steps involved are:

1. Model selection: Determine reservoir characteristics and assumptions for typical candidate gas fields to apply existing analytical correlations for hydrogen storage models in depleted gas reservoirs. Demonstrate with natural gas fields in the U.S. Midwest region.

2. Implementation: Analytical modeling-based framework for rapid assessment of key UHS performance metrics such as hydrogen storage capacity, hydrogen loss via diffusion to the overlying caprock and the sustainable well operational capacity (i.e., well deliverability).

3. Comparison: Facilitate understanding of dynamics in the subsurface by comparing hydrogen storage with familiar natural gas and CO_2 analogs in similar environments.

This chapter presents the results of the preliminary analysis in terms of the impacts of various subsurface conditions on the performance metrics evaluated for hydrogen storage schemes, with a focus on the U.S. Midwest region. Chapter 5 details the comparison of performance of hydrogen with natural gas and CO_2 analogs as applicable in these subsurface conditions. It is worth noting that our work focuses on the storage of pure substances (H_2, CO_2, CH_4). Similar considerations on the storage of hydrogen-natural gas mixtures are discussed in Buscheck et al., (2023).

4.1. Preliminary Screening Performance Assessment Modeling Framework

The model selection involves determination of inputs for reservoir characteristics and assumptions for typical candidate gas fields present in the U.S. Midwest region of interest and appropriate analytical correlations for hydrogen storage models in depleted gas reservoirs. To enable this, an extensive database of petroleum reservoirs in the U.S. Midwest region compiled as part of the Midwest Regional Carbon Sequestration Partnership (MRCSP) was utilized (Lewis et al., 2021). This database contains data on nearly 19,000 reservoirs that are a mixture of petroleum, coal bed methane and water fields. The reservoirs were filtered to include only gas and gas storage fields. The final dataset used in this study captures 2063 unique gas and gas storage fields, some of which contain multiple reservoir units, with necessary reservoir properties for the modeling – depth, areal extent, thickness, and porosity. Figure 4-1 shows the geographic location of the fields identified in the study, covering areas of New

York, Pennsylvania, West Virginia, Kentucky, Ohio, Indiana, and Michigan, which is generalized as the U.S. Midwest region. Figure 4-2 shows the ranges of pressure and temperature conditions in these fields. Pressures and temperatures are calculated using standard hydrostatic and geothermal gradients where not reported for the current screening-level assessment. Table 4-1 shows descriptive statistics for variability in the following key reservoir characteristics of depth, thickness, areal extent, porosity, and water saturation in the candidate gas fields of interest.

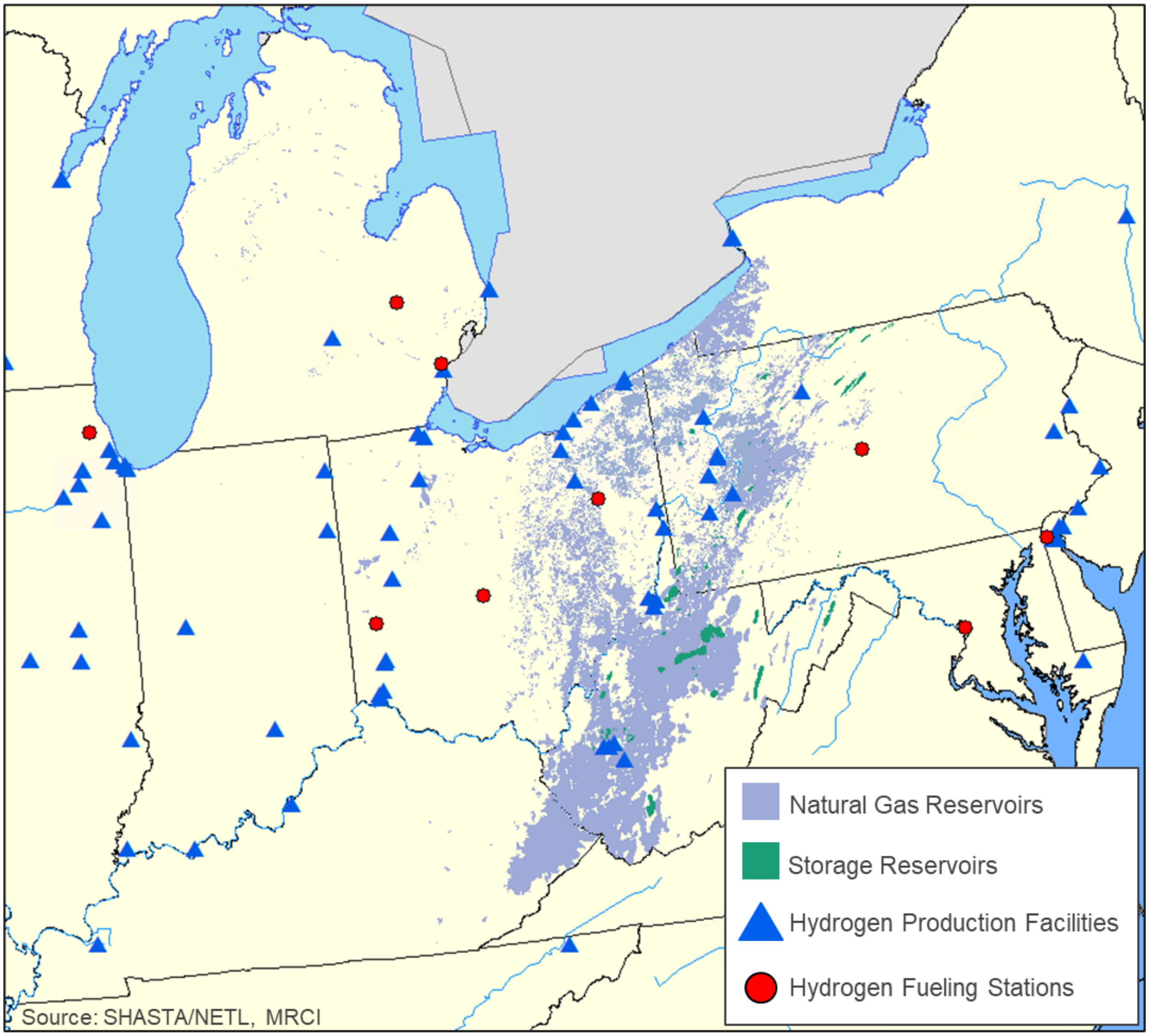

Figure 4-1: Map view of the gas and storage fields being evaluated for UHS potential in the current study. Data from MRCSP Petroleum Fields database (Lewis et al., 2021).

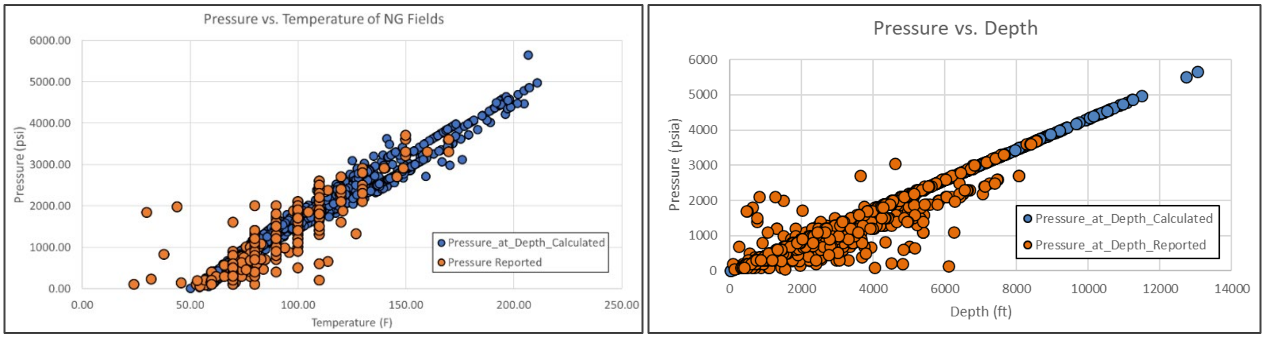

Figure 4-2: Pressure vs. Temperature (left) and Pressure vs. Depth (right), both calculated (blue) and reported (orange), for depleted gas fields considered in this study. The reported values account for a wider range of conditions, where reservoirs may have been over- or under-pressured relative to their depth. Data from MRCSP Petroleum Fields database (Lewis et al., 2021).

Table 4-1: Descriptive statistics of the input dataset from MRCSP Petroleum Fields Database.

	Min	25th Percentile	Median	75th Percentile	Max
Depth (ft)	10	1799.5	2700	4185.5	13050
Thickness (ft)	2	12	20	38	3324
Area (acre)	2.7	274	1803	7969	1215735
Porosity (%)	1	7	9	11	26
Water Saturation (%)	2	28	41	50	91

A major challenge in assessing the potential for UHS in depleted gas fields arises from the unique properties of molecular hydrogen. Understanding the thermophysical properties of hydrogen gas is thus critical to understanding its behavior in underground storage applications. Compared to analogous storage fluids such as natural gas and CO_2, hydrogen has lower density and is highly diffusive. Figure 4-3 shows the properties of density, viscosity, solubility and diffusivity (both in pure water) across a wide range of temperatures and pressures. The densities and viscosities were generated through the NIST-managed software, REFPROP (Bell, 2013). Aqueous solubility and diffusivity data for hydrogen are referenced from Chabab et al. (2020), and the Engineering Toolbox online resource, respectively. The current study assumes that the hydrogen diffusivity coefficient varies with temperature but not with pressure resulting in conservative (read: higher) estimates. Sources exist (O'Hern and Martin, 1955; Chou and Martin, 1957) that show diffusion coefficients in elevated pressure gas-gas systems decrease with increasing pressure. It is unclear if this behavior is also exhibited in gas-liquid systems. Values for the fluid properties in pressure and temperature conditions outside the provided ranges are extrapolated from the dataset.

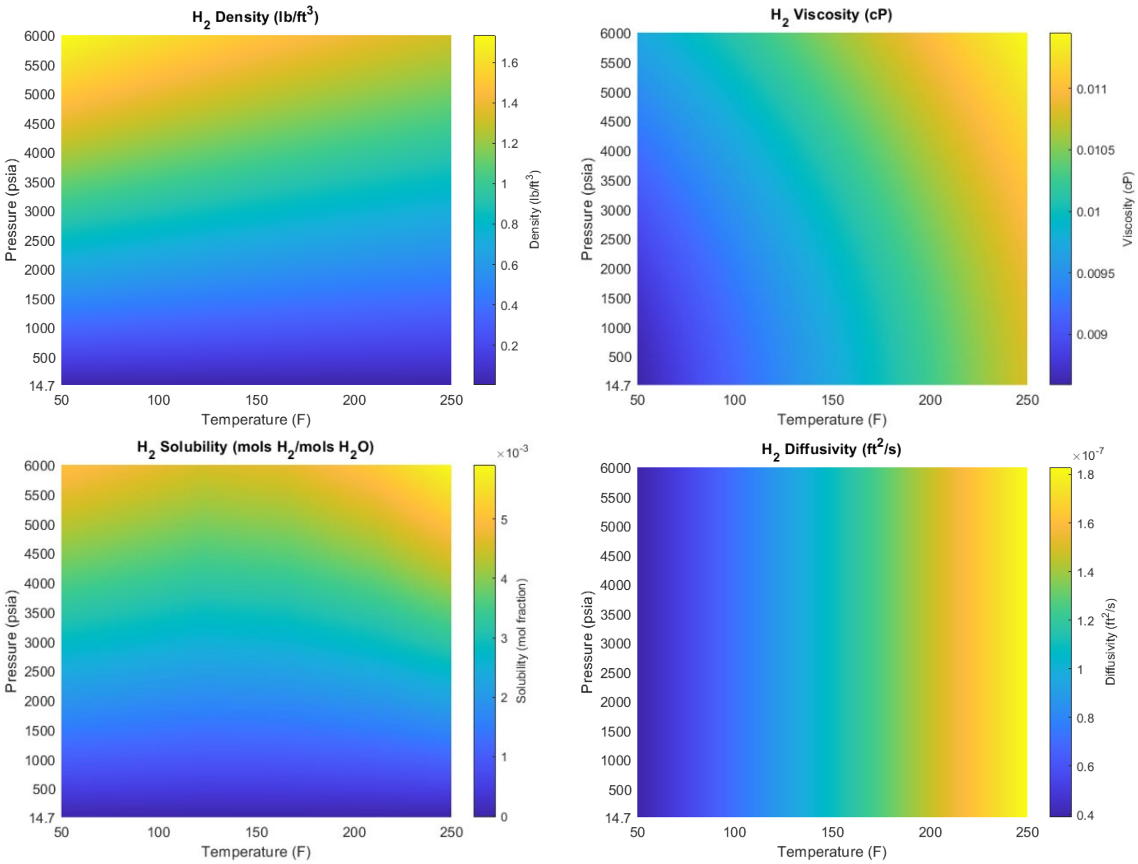

Figure 4-3: Relevant properties of hydrogen gas for this study. Shown are Density (upper-left), Viscosity (upper-right), Solubility (lower-left) and Diffusivity (lower-right) as a function of pressure and temperature.

4.2. Underground Hydrogen Storage Key Performance Metrics

Using concepts similar to those presented in the analysis of Amid et al. *(*2016), analytical models for potential hydrogen storage capacity in depleted gas reservoirs, potential fate of hydrogen in-situ, and amount of sustainable well operational capacity have been implemented in Excel based on assumptions identified in Section 4.1. The following metrics are explored in the assessment (all equations are in field units):

- **Storage Capacity –** A theoretical volumetric estimate of the total amount of hydrogen gas (or any storage fluid in general) that can be stored in the porous depleted reservoir if all the accessible pore volume (excluding water) is hydrogen saturated. Storage capacity, V_G , is calculated via the following Equation 4-1,

$$\frac{V_G}{V_R} = \frac{y_G \varphi (1 - S_{wi}) P}{Z P_0} \frac{T_0}{T} = y_G \varphi (1 - S_{wi}) \frac{\rho}{\rho_0} \qquad \text{Equation 4-1}$$

where:

V_G = volume of stored gas (SCF)
V_R = bulk reservoir volume (SCF)
y_G = working gas fraction – assumed to be 1 for capacity estimates (dimensionless)

φ = reservoir porosity (dimensionless)
S_{wi} = reservoir (or connate) water saturation (dimensionless)
P, T, ρ = pressure, temperature, density at reservoir conditions (psia, Rankine, lb/ft^3)
P_0, T_0, ρ_0 = pressure, temperature, density at surface conditions (psia, Rankine, lb/ft^3)
Z = gas compressibility (dimensionless)

The secondary equation shown above is a simplification of the first version using the non-ideal gas equation. Expressed in terms of densities rather than compressibility, pressure and temperature, it is easy to identify the primary influencing factors on storage capacity – the more a substance can be condensed at reservoir conditions, the more gas can be stored. Hydrogen tends to be less compressible (read: smaller density ratio) than CO_2 and methane and hence requires larger reservoir volume to store the same mass of gas. The study presents these theoretical storage estimates, as well as a more realistic estimate which considers cushion gas.

- **Losses to Diffusion** – Estimate of the gas volume lost via diffusion to overlying caprock and/or underlying aquifers. This performance metric investigates the storage integrity in order to understand the scale of loss involved in hydrogen storage projects given the greater diffusivity of hydrogen in comparison to methane. The amount of hydrogen lost through dissolution into formation water and diffusing away from the reservoir of interest into the overlying caprock can be assessed by applying standard diffusion models (Crank, 1979). This value can be compared with the injected amount of hydrogen (assuming the total storage capacity is the injected quantity) for a preliminary conservative determination of the fraction of hydrogen lost by dissolution or diffusion through the overlying caprock zone after a given time. Diffusive Losses, V_{dG}, are calculated using the following Equation 4-2,

$$\frac{V_{dG}}{A} = 2Sol_G\sqrt{\frac{D_e\varphi_d t}{\pi}} \qquad \text{Equation 4-2}$$

$$D_e = D_G\varphi_d\,\delta/\tau$$

$$\tau = \varphi_d^{1-m}$$

where:

V_{dG} = volume of gas lost to diffusion (SCF)
A = areal extent of the reservoir (ft^2)
Sol_G = solubility of gas in the formation water (ft^3 solute / ft^3 solvent)
D_e = effective diffusion coefficient for gas (ft^2/s)
φ_d = porosity of diffusive medium, in this case, caprock (dimensionless)
t = time (s)
D_G = diffusion coefficient of gas in pure water (ft^2/s)
δ = constriction factor of the pores (equal to 1)
τ = tortuosity of the pores (dimensionless)
m = cementation coefficient (= 2 in this study)

The amount of storage gas that diffuses into the caprock over a given time period, and is therefore ‘lost’, depends primarily on two elements: how much gas dissolves into the formation water, and how easily the dissolved gas can flow within the formation. The former element is dependent entirely on the solubility coefficient of gas in formation water at reservoir conditions. Solubility decreases with increasing salinity, so we consider solubility in pure water as the limiting case. The latter element, defined as the diffusion coefficient, has several controlling factors that stem from characteristics of both the gas and the diffusive medium itself (caprock). A higher diffusion coefficient will lead to quicker diffusion and therefore more diffusive losses. The characteristics of the porosity network (i.e., connectivity of the pores) within the caprock are directly correlated with the diffusion coefficient. An increase in caprock porosity indicates there is more connected space into which the diffused gas may flow, which will lead to higher diffusive losses. Tortuosity, on the other hand, is an intrinsic property of the rock that is inversely correlated with the diffusion coefficient. A lower tortuosity indicates that the path gas molecules follow within the pore network tends to be straighter, leading to faster diffusion and therefore higher diffusive losses within a given time. This study examines stored gas lost to diffusion assuming one year of storage.

- **Well Deliverability** – Critical operational performance metric that provides estimate of the maximum rate at which gas can be extracted from the underground storage facility to be delivered to end users. The standard theoretical relationship for gas well deliverability was presented by Houpeurt in 1959. The method is derived from first principles and considers both laminar and turbulent flow present in and around a producing wellbore (Houpeurt, 1959; Forchheimer, 1901). The study uses the universally applicable pseudopressure formulation of this method to assess the potential deliverability of hydrogen. Deliverability, q_g, is calculated using the following set of equations:

$$m(\bar{p}_R) - m(p_{wf}) = aq_g + bq_g^{\ 2} \qquad \text{Equation 4-3}$$

$$m(\bar{p}_R) - m(p_{wf}) = 2\int_{p_{wf}}^{\bar{p}_R} \frac{pdp}{\mu Z} \qquad \text{Equation 4-4}$$

$$a = \frac{1422T\left(ln\frac{r_e}{r_w} - \frac{3}{4} + s\right)}{kh}$$

$$b = \frac{1422T}{kh}D$$

$$D = \frac{(2.715\text{x}10^{-15})\beta k M P_0}{h\mu r_w T_0}$$

$$\beta = (1.88\text{x}10^{10})k^{-1.47}\varphi^{-0.53}$$

where:

q_g = gas deliverability (MCF/day)
$m(p)$ = pseudopressure evaluated at pressure p (psia^2/cp)
$\bar{p}_R$ = average reservoir pressure (psia)
p_{wf} = flowing well bottom-hole pressure (psia)
a = laminar flow coefficient (psia^2/cp/MCF/day)
b = turbulent flow coefficient (psia^2/cp/MCF^2/day^2)
μ = gas viscosity (cp)
r_e = well drainage radius (ft)
r_w = wellbore radius (assumed as 0.25 ft.)
s = wellbore skin factor (dimensionless)
k = reservoir permeability (mD)
h = reservoir thickness (ft)
D = non-Darcy flow coefficient (day/MCF)
β = turbulence factor (ft^{-1}) (Jones 1987)
M = molecular weight (lb/lbmol)

Deliverability, q_g, is impacted by the laminar flow contribution and non-Darcy flow contribution to the pseudopressure differential (analogous to pressure differential). The pseudopressure drop, $m(\bar{p}_R) - m(p_{wf})$, in Equations 4-3 and 4-4 captures pressure and fluid property impacts. A larger difference in pressure between the reservoir and flowing wellbore will lead to a greater flow rate of extracted gas. Less viscous and less compressible fluids tend to flow in bulk more easily and hence have higher deliverability.

The pseudopressure drop due to laminar flow and well conditions is captured by the term, aq_g in Equation 4-3. The flow coefficient *a* is dependent largely on reservoir and wellbore properties. The deliverability is thus positively correlated with the permeability-thickness product of the reservoir. The drainage radius (r_e), determined by reservoir geometry and wellbore configuration, has an inverse correlation with deliverability. The effective well drainage area is estimated by dividing the areal extent of the field by number of production wells as this represents the approximate proportion of reservoir accessed by a single well when all wells are operational.

The pseudopressure drop due to inertial-turbulent flow effects is captured by the term, bq_g^2, in Equation 4-3. The flow coefficient *b* is dependent on wellbore, reservoir, and fluid properties. The influence of turbulent flow is largely secondary at low gas velocities. In other words, at lower pressure differentials, bulk flow is the dominant mechanism of fluid transport. Turbulence becomes much more impactful at higher pressure differentials, and the rate of increase in deliverability slows down.

The mechanisms discussed above are also captured graphically by Inflow Performance Relationship (IPR) curves, which detail the deliverability of a given well as a function of bottomhole flowing pressure. Figure 4-4 gives an example of a typical IPR curve for a gas well. Deliverability is zero when the bottomhole pressure is equal to reservoir pressure (at stabilized shut-in wellhead pressure) and increases to a maximum as the wellbore flowing pressure approaches zero. This theoretical maximum deliverability is known as the Absolute Open Flow (AOF) potential of a well and provides a useful metric of comparison between different wells (Ahmed, 2010). The deliverability values reported in the current screening assessment correspond to this theoretical maximum AOF.

The dataset for the current study was limited by the lack of publicly available permeability data in our candidate fields. Only 14 of the 2063 fields in our dataset included permeability estimates. Thus, the current study provides maximum deliverability estimates for only these 14 fields to demonstrate the preliminary performance assessment framework. The deliverability for hydrogen can be easily obtained for operating gas storage fields using the knowledge of deliverability metrics for natural gas. The flow coefficients for deliverability of hydrogen can be estimated by calculating the *a* and *b* coefficients through property ratios of hydrogen and natural gas as demonstrated in Amid et al. (2016).

The results of this screening assessment for high-level hydrogen storage performance in depleted gas fields representative of the U.S. Midwest region are discussed in the next section.

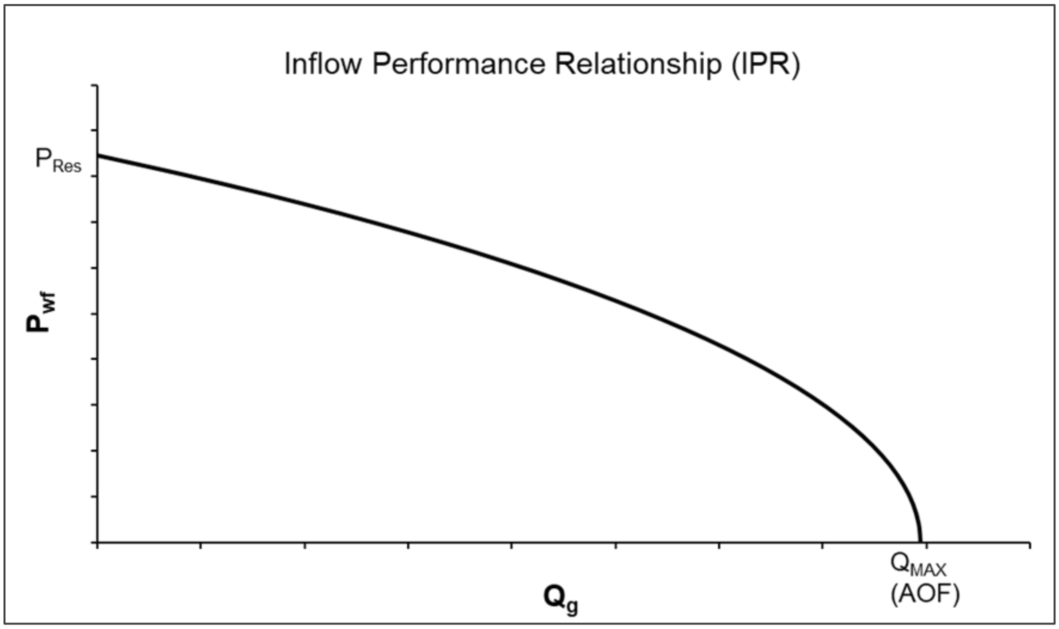

Figure 4-4: Example Inflow Performance Relationship (IPR) curve for a gas well using the pseudopressure method. Curve shows well inflow rate as a function of wellbore flowing pressure. Deliverability is zero when the wellbore pressure equals the reservoir pressure and reaches a theoretical maximum (AOF) when wellbore pressure is zero.

4.3. Preliminary Screening Performance Assessment Results

Results of the preliminary analytical-based screening assessment on hydrogen potential for each of the metrics described in the previous section are summarized in Table 4-2. Key takeaways are:

- Median storage capacity for hydrogen in depleted natural gas fields in the U.S. Midwest is 5.93 BCF, which equates to a mass of 1.14 MMT. Depleted petroleum fields used for UHS are expected to require cushion gas fractions of around 50% (Papadias & Ahluwalia, 2021; Malachowska et al., 2022), indicating a median *usable* storage capacity of around 3 BCF (or 0.6 MMT). The total available capacity in the Midwest region, according to this dataset, is 82.5 billion metric tonnes, or 41 BMT assuming the same 50% cushion gas fraction.
- While diffusive losses are seen as high as 0.8% in some reservoirs, the total calculated diffusive losses are around 0.0001% of the total storage capacity. This indicates that, despite hydrogen's high diffusivity relative to natural gas (around 2.5 times higher), diffusion of storage gas through caprock is likely not a significant issue.
- Well deliverability is site-specific and depends on rock properties of a given reservoir. Median deliverability potential for hydrogen at sites with available permeability data (14 data points) was 2.8 MMCF/day. Well productivity index (deliverability over pressure drop from reservoir to wellbore) exhibits a linear relationship with the permeability thickness product, *kh*, as expected. Inflow performance relationship curves are thus crucial to designing wells for UHS.

Table 4-2: Summarized results of hydrogen screening assessment on depleted natural gas fields in the U.S. Midwest region.

Hydrogen	Min	25th Percentile	Median	75th Percentile	Max
Storage Capacity (MMCF)	2.67E-01	8.32E+02	5.93E+03	3.67E+04	9.13E+07
Mass Storage Capacity (tonnes)	1.93E-01	1.35E+05	1.14E+06	6.71E+06	1.83E+10
Diffusive Losses (MMCF)	1.61E-04	2.78E-01	1.97E+00	8.97E+00	1.59E+03
Diffusive Losses (%)	2.93E-04	1.75E-02	3.21E-02	5.45E-02	8.01E-01
Well Deliverability (MCF/D)*	2.67E+02	1.66E+03	2.79E+03	7.78E+03	3.27E+04

*Deliverability statistics from subset of 14 fields with permeability data available as mentioned in Section 4.2.

Data relationships in our analytical models were examined to glean insight into desirable targets for UHS. Figure 4-5 shows the storage capacity by mass as a function of depth, thickness and areal extent. Perhaps unsurprisingly, the strongest relationship exists between capacity and the geometric dimensions of the reservoir. Areal extent and thickness both show a strong positive correlation. Depth also appears to show a positive correlation with storage capacity, likely due to the impacts of density. A deeper reservoir implies higher pressures, which in turn implies higher densities at reservoir conditions. This means more mass is being stored, and therefore also a higher surface volume. Reservoir properties which are not included in the plots – namely porosity and water saturation – are seen to exhibit no strong relationship with storage capacity despite contributing to an increase or decrease in the amount of available storage space for hydrogen. The lack of a relationship is likely due to the fact that the range of variability in the geometric dimensions of potential reservoirs is much greater and dominates impact on storage capacity results obtained in the study.

Figure 4-6 explores similar relationships in the results on fractional diffusive losses (as a fraction of storage capacity). The reservoir thickness has a strong correlation here as well, in this case an inverse or negative correlation. This can be explained by the fact that in thicker formations, a smaller fraction of the stored gas is in contact with the caprock interface relative to thinner reservoirs. Depth and areal extent, on the other hand (not pictured), both have no strong correlation with the fraction of gas lost to diffusion. Diffusion coefficient and solubility, similar to the depth and areal extent (not pictured), seem to also have no strong correlation to the results, which is likely due to the narrow range of those properties exhibited at the reservoir conditions of interest (see Figure 4-3).

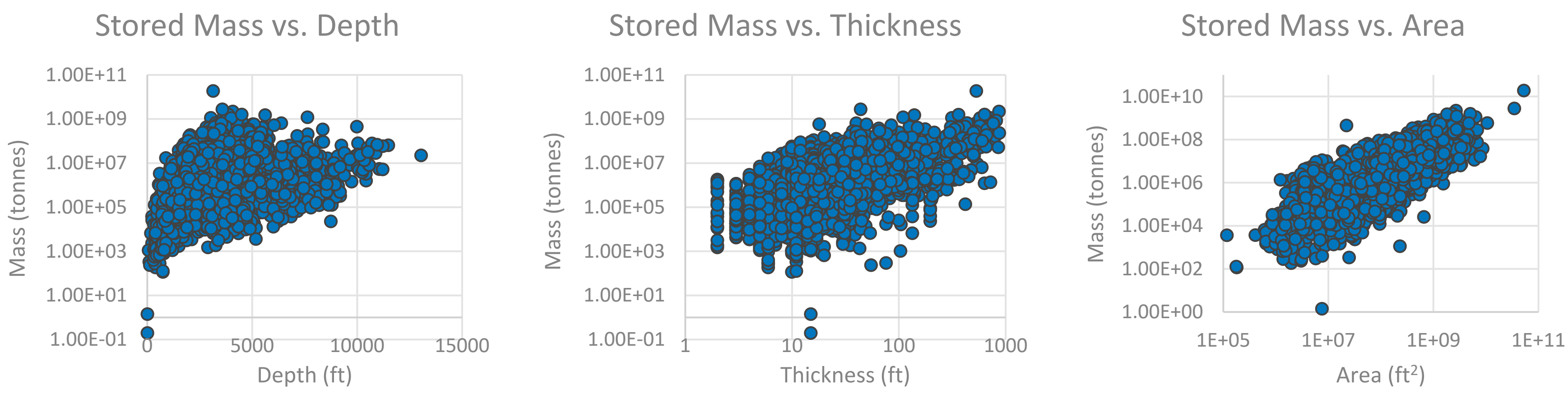

Figure 4-5: Storage Capacities of hydrogen (in Mass) as a function of various inputs to the analytical models. Titles in each panel indicate the relationship shown. Some scales are logarithmic to better illustrate relationships between variables.

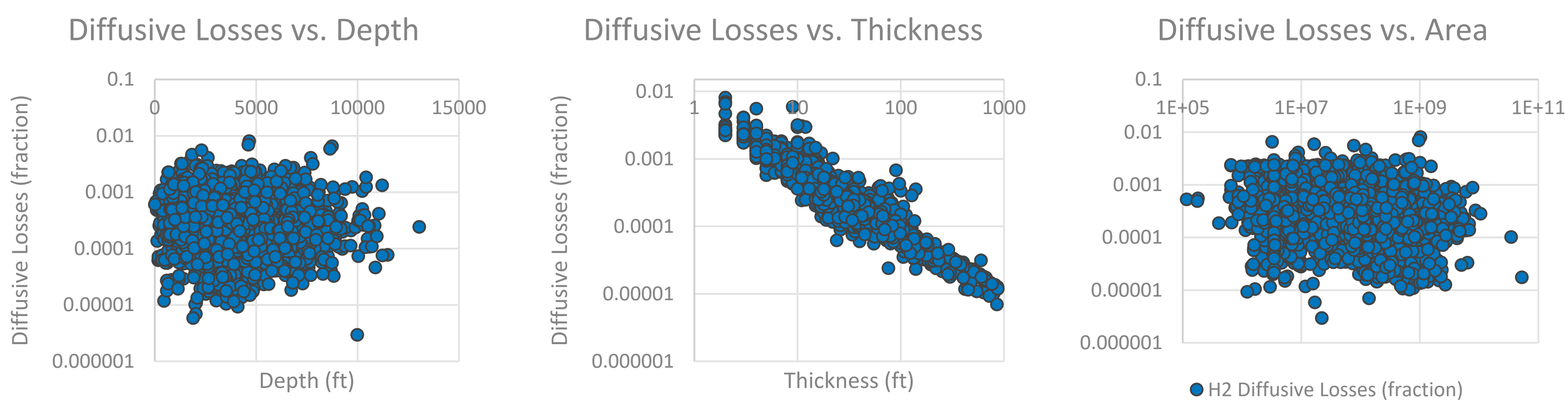

Figure 4-6: Diffusive losses, expressed as a fraction of storage capacity, for hydrogen as a function of various inputs to the analytical models. Titles in each panel indicate the relationship shown. Some scales are logarithmic to better illustrate relationships between variables.

The strongest indicator of deliverability for a given reservoir is the permeability-thickness product of that reservoir (*kh*). The left panel of Figure 4-7 displays a strong positive relationship between maximum deliverability and *kh*, though a significant outlier is present at ~3000 mD.feet. This outlier corresponds to a thick but shallow sandstone reservoir. Shallow formations are limited in the magnitude of pressure that can safely be maintained, which significantly limits deliverability. The relationship is much clearer, as shown in the right panel of Figure 4-7, when represented as the productivity index of the well (deliverability over pressure drawdown). This conforms to the conventional oil and gas industry performance metric of productivity index that is linearly correlated to *kh and* can serve as a suitable metric of maximum potential well deliverability in a given reservoir.

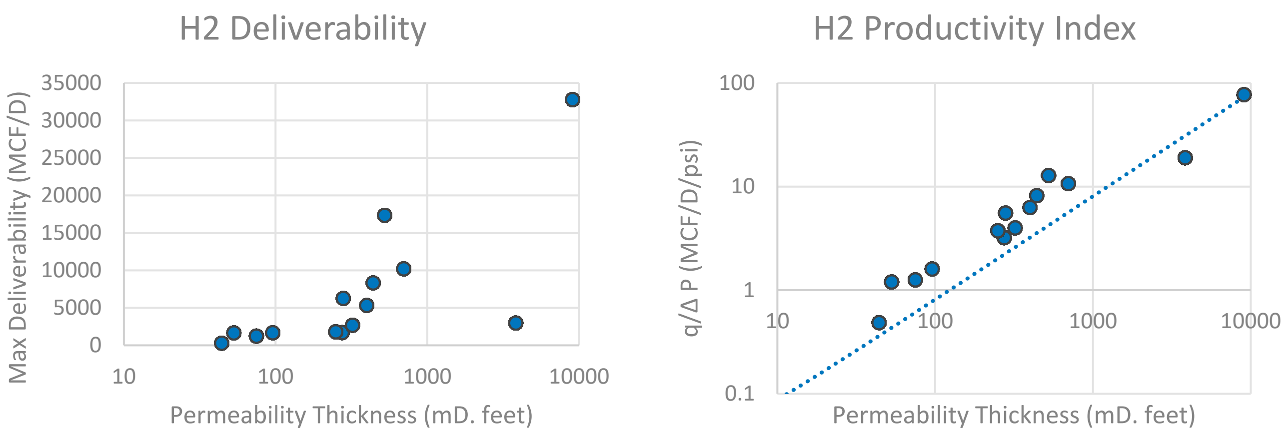

Figure 4-7: Deliverability and Productivity Index estimates for Hydrogen in depleted gas fields with available data. Deliverability generally increases with permeability thickness.

There does not appear to be any strong correlation between deliverability and our other two metrics. Permeability is a crucial parameter that impacts well deliverability and can vary widely between different lithologies and depositional settings. As a result, deliverability should be assessed on a site-specific basis and theoretical IPR curves can effectively inform the determination of appropriate operational conditions for that UHS site. An IPR curve for a representative field from our dataset, the Granny Creek – Stockly field in West Virginia, is shown in Figure 4-8. These curves assist in the operational design since an operator can estimate the number of wells and operating pressures necessary to meet a given energy demand scenario. Once operations begin, IPR curves are updated to be constrained by field data.

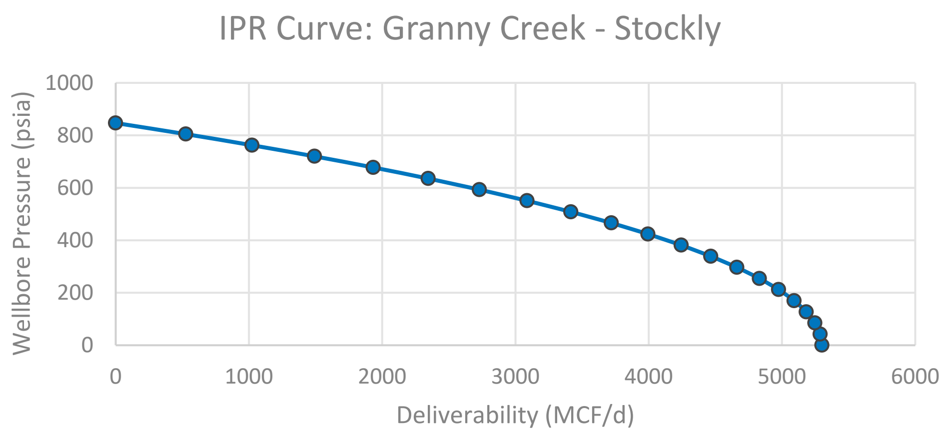

Figure 4-8: Hydrogen IPR Curve for a representative depleted field, the Granny Creek – Stockly gas field in West Virginia. Generation of IPR curves at a given field can effectively inform the operational design of a UHS site.

As shown in Figure 4-9, the storage capacity and diffused volume estimates are highly correlated. As the amount of stored gas increases, the total amount of diffused gas increases. This stands to reason as there is a larger supply of gas present in the reservoir to feed the diffusive processes. However, the diffused volume fraction actually exhibits a negative correlation; in other words, the more gas that is stored in a reservoir, the smaller fraction of that gas is lost to the formation. This indicates that moving toward hub-scale storage strategies, rather than distributed strategies, might be a better approach in limiting asset loss. At the same time, total diffusive losses cap out at 1% of total storage volume, and are typically less than 0.1%, so diffusion as a whole is potentially not a significant source of asset loss. Detailed caprock testing is expected to be valuable to confirm these results on a site-specific basis.

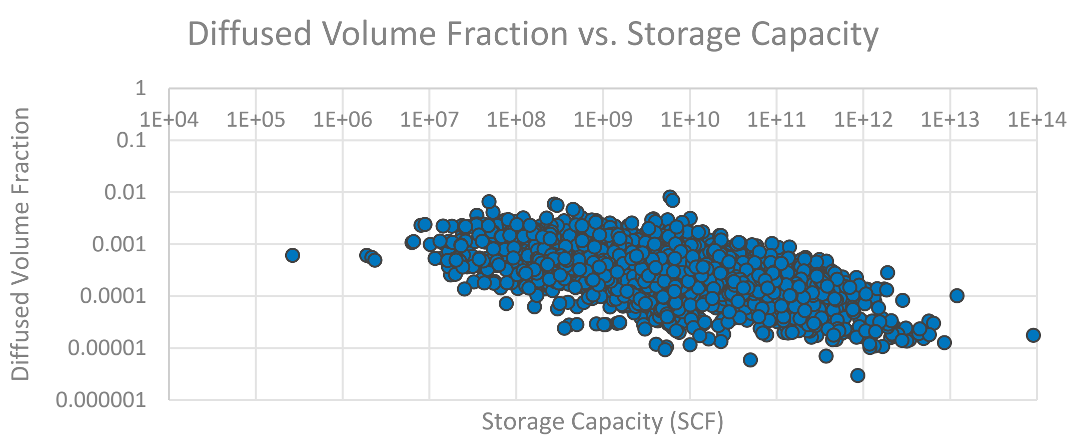

Figure 4-9: Diffused volume fraction of hydrogen as a function of volumetric storage capacity for the considered dataset. Plot is log-log to better illustrate relationships between data.

Figure 4-10 shows a map view of the storage capacity (left panel) and diffusive loss (right panel) results for our dataset. Given the large number of proximal fields in Appalachia, this region appears highly promising for UHS from a development perspective. Diffusive losses are negligible, ranging from 0.1% to 0.0001% as a fraction of the total storage capacity. It is worth noting that in both capacity and diffusive losses, shale formations tend to represent end-members of the distribution. Further research on the factors driving hydrogen storage performance in different lithologies would be beneficial as mentioned in Chapter 2.

A comparable study to the work done in this effort was carried out by the US-DOE funded SHASTA project and published in early 2023. Using publicly available data on the working gas capacities of operating natural gas storage facilities in the U.S., they estimated the total energy capacity in the U.S. if all facilities were converted to UHS. According to this work, the total U.S. capacity in converted natural gas storage facilities, assuming 100% H_2 working gas, as 327 TW-hours (TWh). This equates to 9.8 MMT of hydrogen (Lackey et al., 2023). The estimated total capacity of Hydrogen for the Midwest region, assuming a 50% working gas fraction, is 41.2 BMT (of which storage fields make up ~2%). Using energy conversion factors provided by the GREET tool (GREET, 2008), this mass of gas could provide 1.38 million TWh of energy – over 4000x more than the reported capacity of gas storage fields for the entire U.S. Depleted gas fields thus offer significant potential to anchor large-scale UHS.

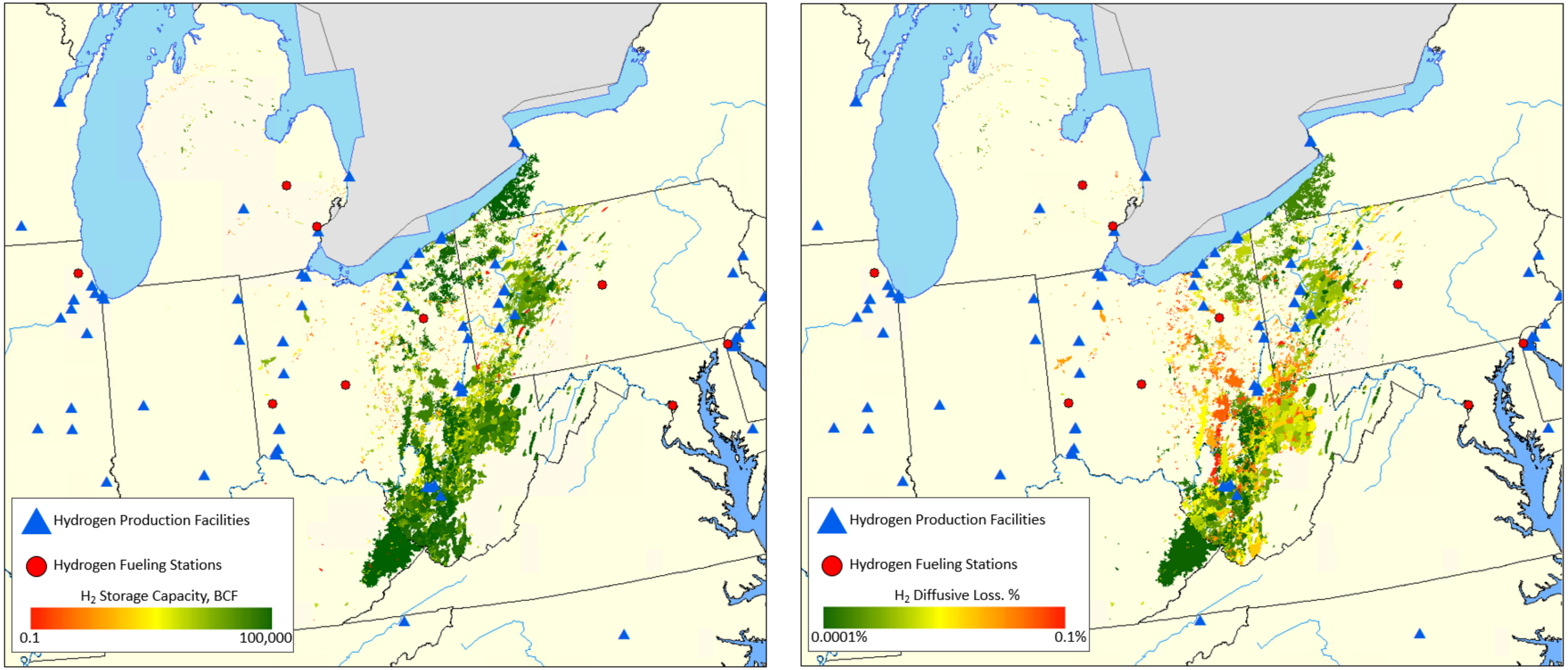

Figure 4-10: Geographic distribution of storage capacity and diffusive loss metrics for the gas and gas storage fields considered in this study. Also shown are hydrogen production facilities and fueling stations identified throughout the Midwest region.

5.0 Comparing Hydrogen with Analogs in Underground Storage Operations

Since experience from natural gas storage projects for short-term storage and carbon sequestration projects for long-term storage are more prevalent in the US and globally, the current study provides an instructive understanding of UHS using these two more familiar analogous operations of subsurface fluid storage. This Chapter presents a comparison of hydrogen storage performance in the subsurface against traditional or more familiar subsurface storage processes involving CO_2 and natural gas. This serves to improve our understanding of the feasibility and technical considerations involved in the implementation of this emerging technology in depleted gas reservoirs.

5.1. Analogous Storage Gases

A century of industrial experience in underground natural gas storage and the plethora of demonstrations and industrial experience in geologic carbon storage since the 1970s could provide a model of success for underground hydrogen storage – provided we can account for the physical differences between the different storage gases. To that end, we have compared the properties of hydrogen with CO_2 and natural gas at the same pressure and temperature conditions. We use pure methane to represent natural gas in this study. Figure 5-1 compares the values of mass density, viscosity, solubility and diffusion coefficient for each of these three considered substances at the pressure and temperature conditions representative of the considered dataset of depleted natural gas fields detailed in Section 4.1. Pure gas properties of density, viscosity and diffusivity for methane and CO_2 are obtained in addition to hydrogen from the sources given in chapter 4. Solubility data for methane and CO_2 are obtained from Duan et al., 1992; Mishra et al., 2014, respectively.

CO_2 exhibits significantly different property distributions to natural gas and methane because of its phase behavior (Figure 5-2 and Figure 5-3). The critical pressure and temperature of CO_2 are 1071 psi and 87.8^{O}F, both of which fall squarely within the range of pressures and temperatures seen in our dataset (see Figure 4-2). Supercritical CO_2 behaves more similar to a liquid, and thus is significantly denser, more viscous and more soluble than the gases at comparable pressure and temperatures. This pressure and temperature, given typical hydrostatic and hydrothermal gradients, corresponds to a depth of around 2600 feet. Figure 5-3 shows the density and solubility of CO_2 versus depth, with a line indicating the supercritical phase boundary at 2600 feet. The line clearly delineates two separate phase regimes for CO_2, which is also reflected in the modeling results (as will be discussed in Section 5.2). Figure 5-3 shows comparison of the density, viscosity, aqueous solubility and diffusion coefficients for each of the three substances. Hydrogen is both less dense and less viscous than methane and gaseous CO_2. Solubilities are relatively comparable for methane and hydrogen. Lastly, hydrogen is more diffusive than methane and CO_2 at the same pressure and temperature conditions.

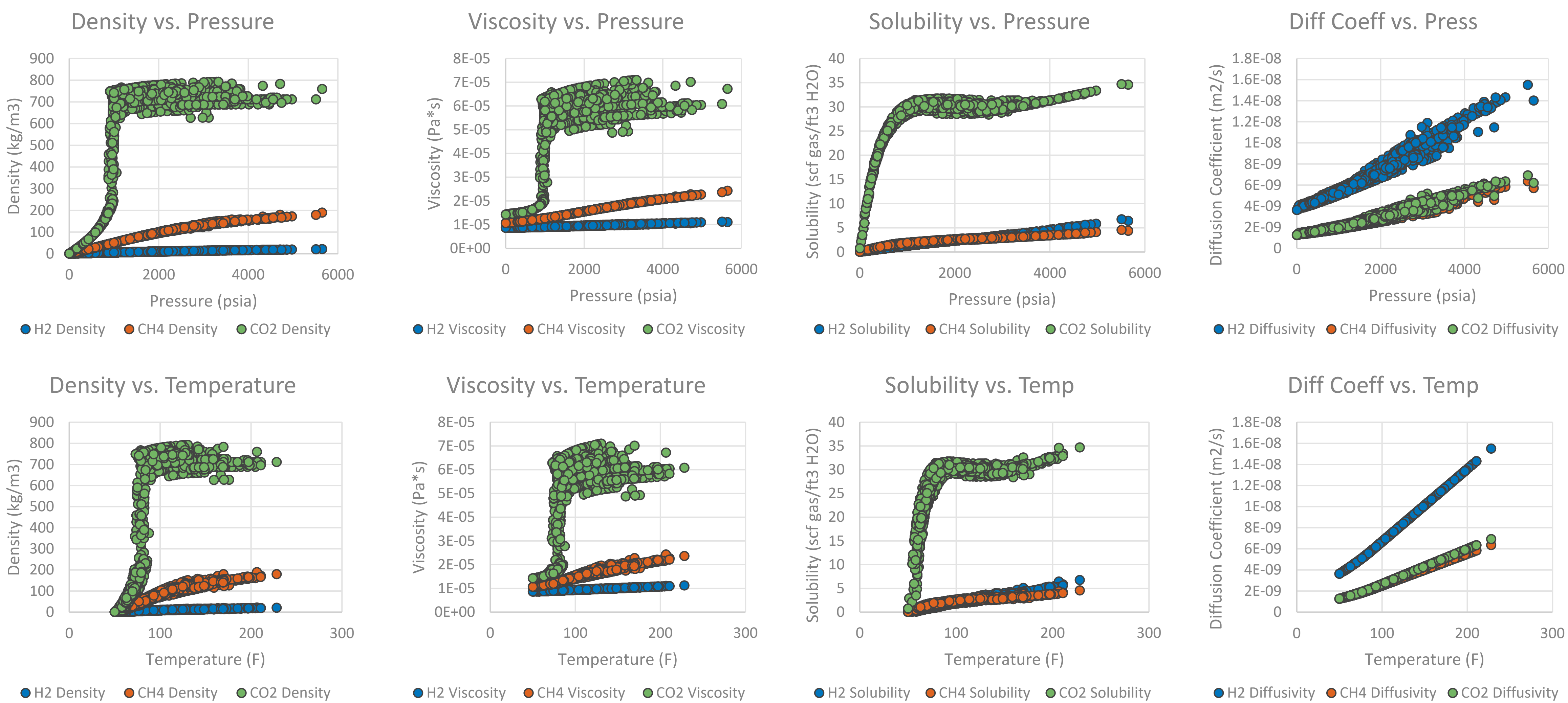

Figure 5-1: Thermophysical properties of pure hydrogen (blue), methane (red) and carbon dioxide (green) as a function of pressure (top) and temperature (bottom).

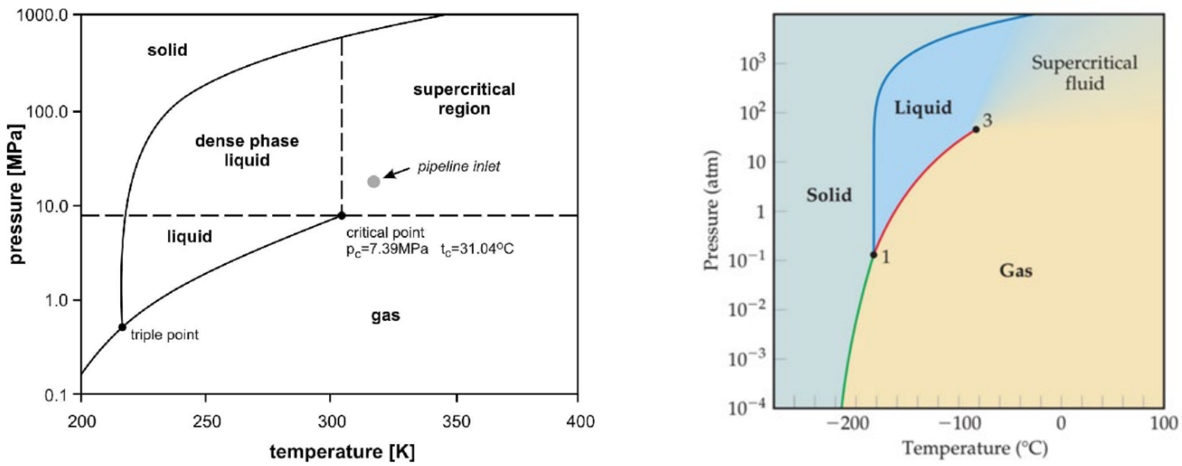

Figure 5-2: Pressure-Temperature phase diagrams for CO_2 (left) and CH_4 (right). Images taken from Witkowski et al., 2014 and Brown et al., 2011, respectively.

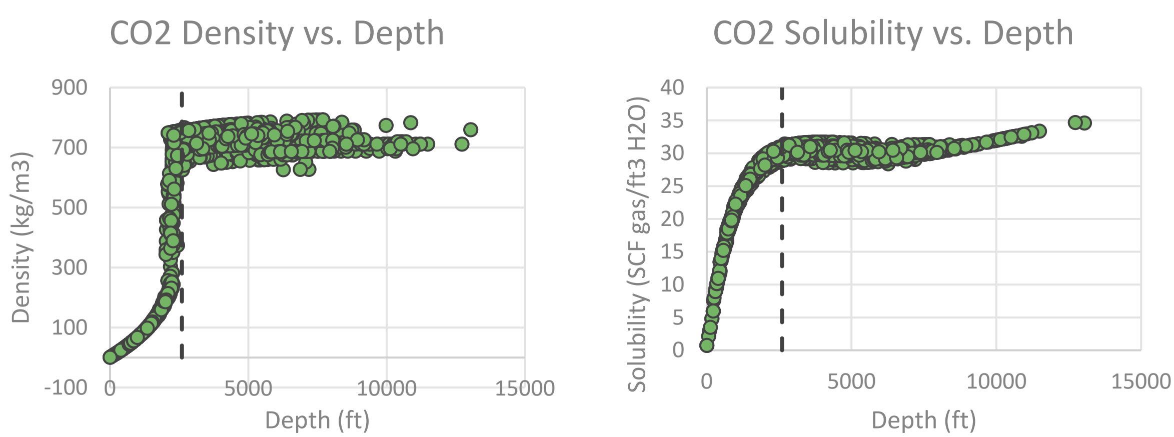

Figure 5-3: Density and solubility of carbon dioxide as a function of depth. The dashed line indicates 2600 ft, an impromptu phase boundary between gaseous and supercritical CO_2.

5.2. Underground Storage Performance Comparison for Analogous Gases

The three fundamental storage performance metrics defined in Section 4.2 are evaluated for CO_2 and natural gas to compare with hydrogen over the pressure and temperature conditions that are relevant to depleted reservoirs of interest in this study. The results of this analysis are summarized in Table 5-1 (CO_2) and Table 5-2 (natural gas). Since injection of CO_2 is strictly for storage purposes, deliverability is not assessed for this substance. A comparison between the storage capacity and diffusive losses of the three gases is shown graphically in Figure 5-4. CO_2 has the highest storage capacity of the three compounds, while methane and hydrogen are comparable. Since hydrogen has the least density, the equivalent mass-based storage capacity is 1-2 orders of magnitude lower than methane and CO_2 in the subsurface respectively. Diffusive losses with methane and hydrogen have comparable results while CO_2 is around an order of magnitude higher (both in diffused volume and volume fraction) due to its higher solubility in similar subsurface conditions.

Table 5-1: Summarized results of CO_2 storage screening assessment on depleted natural gas fields in the U.S. Midwest region.

Carbon Dioxide	Min	25th Percentile	Median	75th Percentile	Max
Storage Capacity (MMCF)	2.56E-01	2.00E+03	1.55E+04	1.01E+05	4.32E+08
Mass Storage Capacity (tonnes)	3.92E+00	1.92E+07	1.67E+08	1.46E+09	8.98E+12
Diffusive Losses (MMCF)	6.27E-03	3.21E+00	2.41E+01	1.08E+02	1.79E+04
Diffusive Losses (%)	6.67E-04	5.12E-02	1.41E-01	3.73E-01	5.07E+00

Table 5-2: Summarized results of natural gas (CH_4) storage screening assessment on depleted natural gas fields in the U.S. Midwest region.

Natural Gas (CH_4)	Min	25th Percentile	Median	75th Percentile	Max
Storage Capacity (MMCF)	2.62E-01	9.76E+02	6.97E+03	4.26E+04	1.10E+08
Mass Storage Capacity (tonnes)	1.49E+00	1.46E+06	1.26E+07	7.51E+07	2.13E+11
Diffusive Losses (MMCF)	1.17E-04	2.10E-01	1.55E+00	6.95E+00	1.20E+03
Diffusive Losses (%)	1.19E-04	1.08E-02	2.20E-02	4.18E-02	4.30E-01
Well Deliverability (MCF/D)*	2.17E+02	1.31E+03	2.22E+03	5.66E+03	2.22E+04

*Deliverability statistics from subset of 14 fields with permeability data available as mentioned in Section 4.2.

The differences between the performance of the different fluids becomes more apparent when looking at ratios of calculated metrics. Figure 5-5 depicts the ratio of calculated storage volume potential for CO_2 to H_2 (left) and natural gas to H_2 (right). The qualitative behavior of these ratios is exactly mirrored in the density ratios between the substances, indicating that density differences are entirely responsible for the differences observed in storage potential. This observation is consistent with the findings of Buscheck et al., (2023), which examines the role of density differences in storage and deliverability efficiency. The ratio between CO_2 and H_2 is significantly higher than for natural gas and H_2, climbing as high as 7 versus a maximum of around 1.3 for methane. The impact of phase change in the case of CO_2 storage is also evident in the left panel in Figure 5-5. The capacity ratio between CO_2 and H_2 rapidly increases with depth until around 2600 feet and then starts to steadily decrease towards unity (indicating the storage capacities are more comparable), corresponding to the gaseous/transition phases in shallower depths followed by the denser supercritical phase in the deeper reservoirs. The inflection point in the right panel of Figure 5-5 is due to thermophysical properties of methane and hydrogen in this pressure/temperature regime.

The ratio between diffusive losses (as a fraction of capacity) – shown in Figure 5-6 – are significantly different between CO_2 and natural gas. The ratio between natural gas and hydrogen steadily decreases with depth from around 1.1 (when methane losses are greater than hydrogen for the same field) to around 0.4, when hydrogen losses are higher. The ratio for CO_2 and hydrogen is always greater than 1, indicating that CO_2 losses are always greater than those of hydrogen in the same field. The ratio is much greater than 1 at depths shallower than 2600 feet, indicating that diffusive losses are a significant issue for gaseous CO_2. This behavior can be observed in Figure 5-6 as well – losses are significant in shallower fields. This substantiates the current best practice of ensuring geologic storage of CO_2 happens in the supercritical regime to ensure containment and storage integrity. The ratio between diffusive losses of CO_2 and hydrogen stays relatively constant beyond a depth of 2600 feet. The ratio for the entire supercritical regime is between 2.6 and 2.2. It is important to note that diffusivity data is rather scarce in the literature, and the impacts of phase differences on diffusivity of CO_2 is unclear. The values used at all pressures and temperatures for all three substances are representative of standard pressure conditions, and therefore the gaseous phase. The potential for different diffusive behavior caused by a phase change in CO_2 is a source of uncertainty in our models.

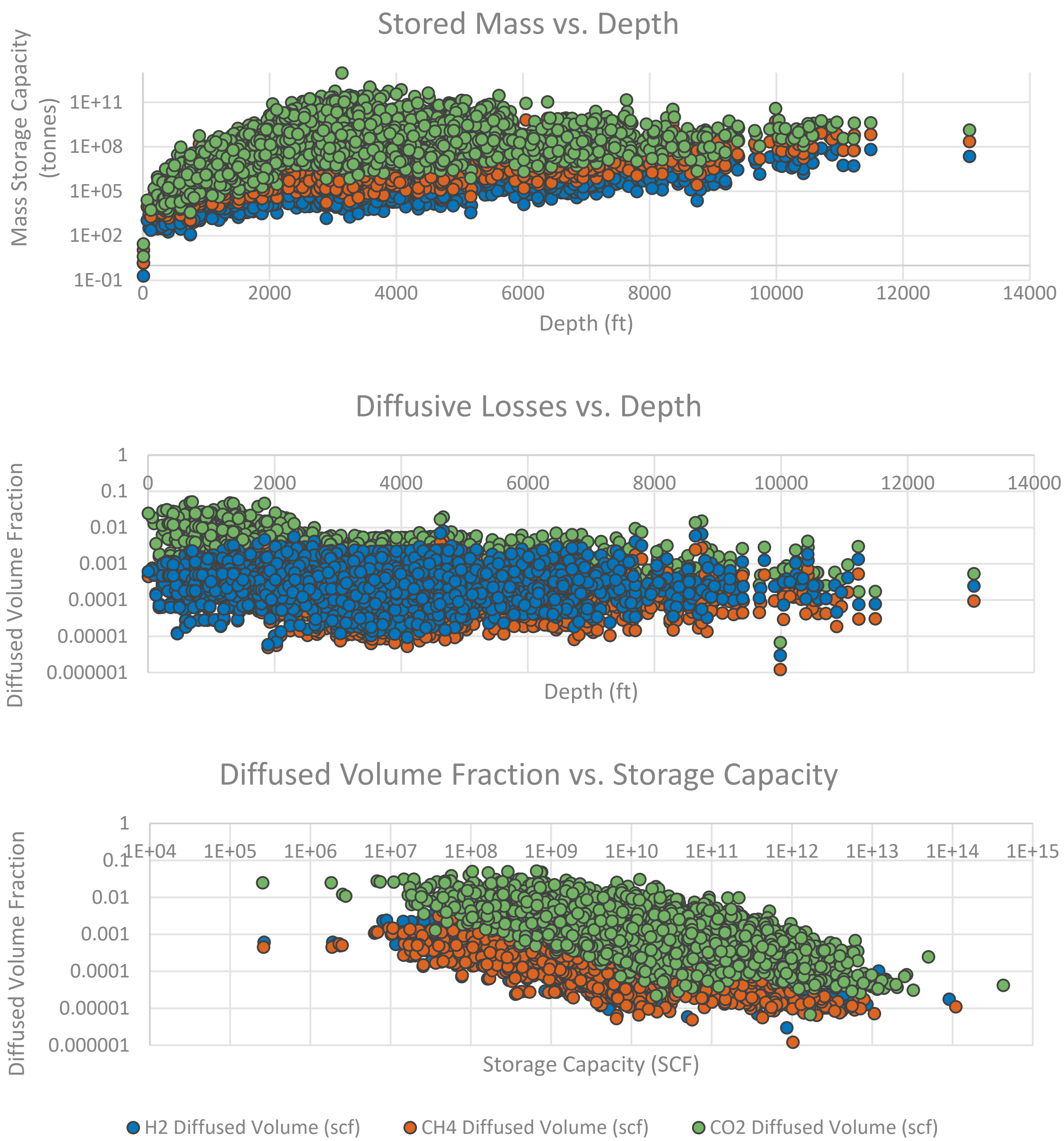

Figure 5-4: Plots showing results of stored mass and diffusive losses for hydrogen (blue), methane (orange) and carbon dioxide (green).

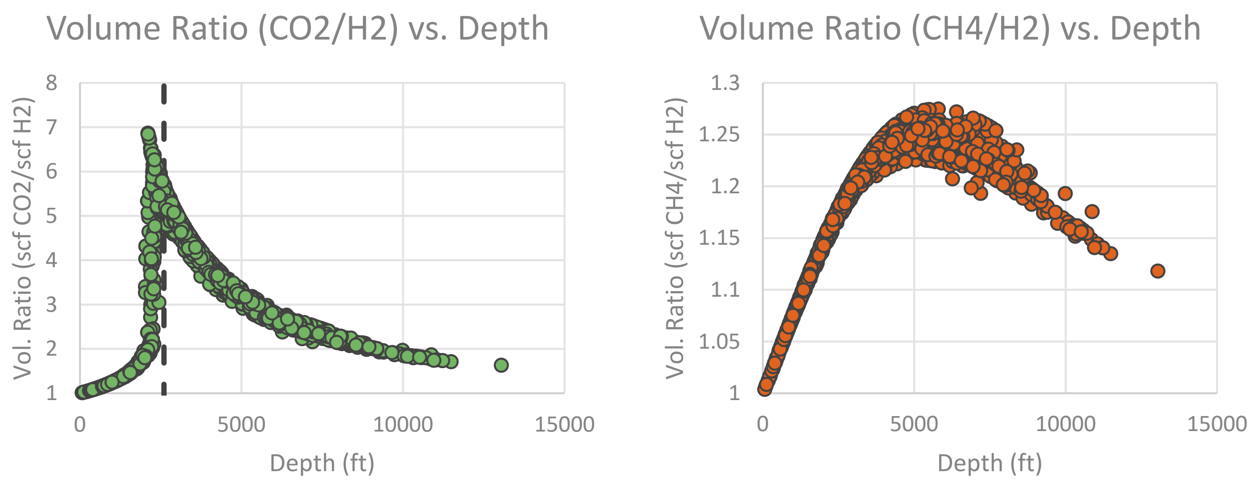

Figure 5-5: Ratio of volumetric storage capacity for analogous fluids (CO_2 – left; CH_4 – right) compared to hydrogen for each of the gas fields in our database. The black dashed line on the left panel is at 2600 feet, showing roughly the division between gaseous and supercritical CO_2.

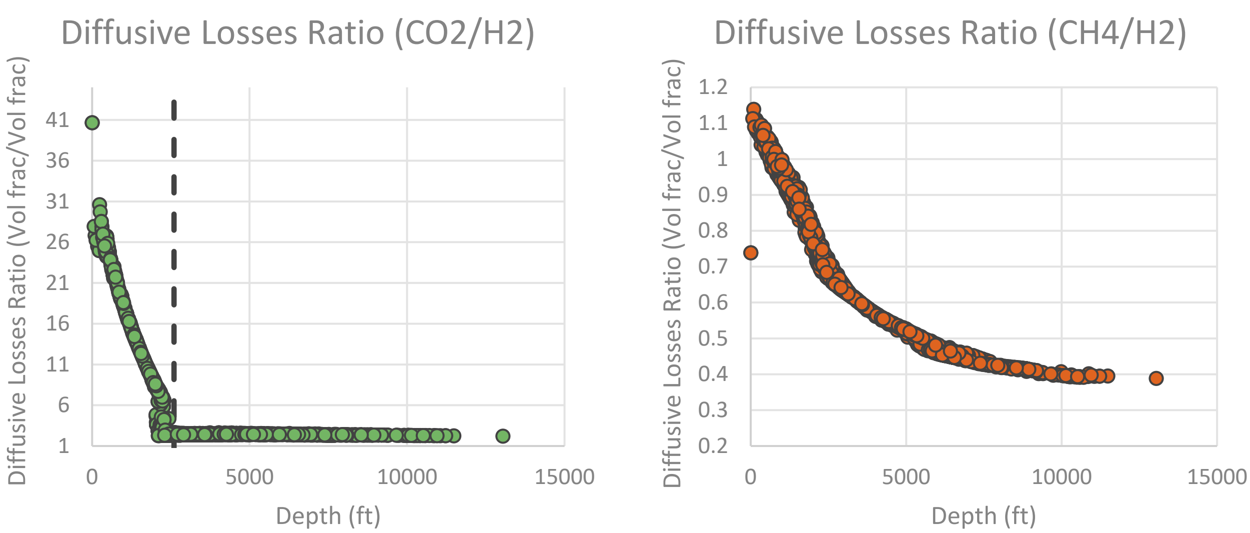

Figure 5-6: Ratio of diffusive loss volume fraction for analogous fluids (CO_2 – left; CH_4 – right) compared to hydrogen for each of the gas fields in our database. The black dashed line on the left panel is at 2600 feet, showing roughly the division between gaseous and supercritical CO_2.

Theoretical maximum well deliverability was calculated for natural gas on the same subset of fields used for the assessment of hydrogen in Chapter 4. The results show the same qualitative trends as seen in Figure 4-7, though deliverability and productivity are slightly lower for natural gas than for hydrogen in the same quality reservoir. Figure 5-7 shows an IPR curve for natural gas at the same representative field as in Chapter 4, Granny Creek – Stockly, co-plotted with the IPR for hydrogen which shows the lower deliverability for natural gas at all operating pressures. However, because of the significantly lower density of hydrogen compared to natural gas (see Figure 5-1), the deliverability by mass of natural gas is significantly higher than that of hydrogen. The bottom panel of Figure 5-7 shows the IPR on a mass-basis for the same field, and the maximum deliverability by mass at AOF for natural gas is approximately 7x higher than the AOF for hydrogen. This illustrates one of the major challenges in using hydrogen as an energy source. The amount of energy delivered per unit volume of hydrogen is significantly lower than that of natural gas, so higher stored volumes will be necessary to meet the same level of energy demand.

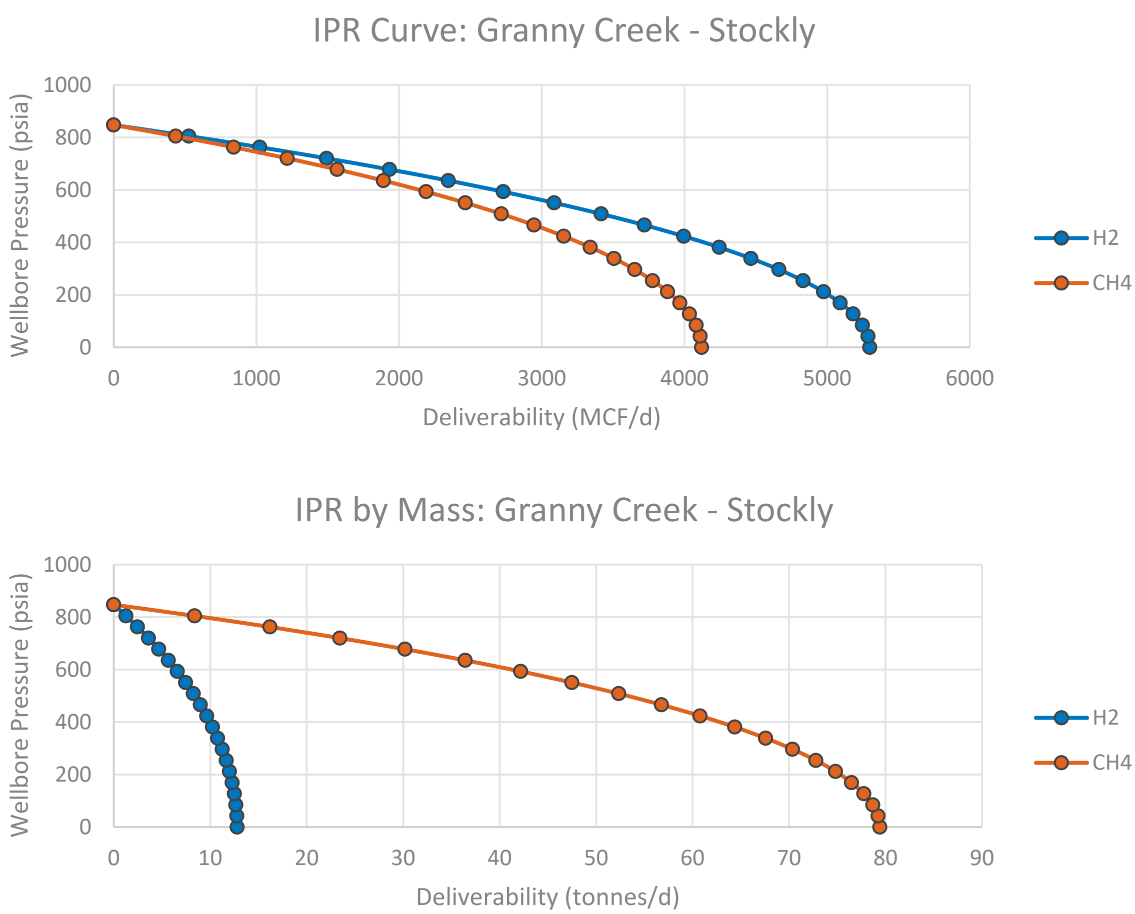

Figure 5-7: Volumetric (top) and Mass (bottom) IPR curves for both hydrogen and natural gas at a representative depleted field – the Granny Creek – Stockly field in West Virginia. Natural gas deliverability is lower than hydrogen at the same flowing pressure. Due to density differences, the mass deliverability of natural gas can be as much as 7x higher than that of hydrogen.

5.3. Discussion and Implications

Table 5-3 shows the total storage capacity, in both surface volumes and masses, for the three storage gases. These capacities are illustrated as tornado plots in Figure 5-8. These plots illustrate that density and compressibility are the primary controlling factors for the differences in storage potential between these substances. Volumes for methane and hydrogen are similar to one another, but the mass that can be stored is a full order of magnitude higher for methane than for hydrogen. The difference in carbon dioxide is even more evident, with a volume ratio of ~4 ballooning to a mass ratio of over 300 when densities are applied. The difference in mass storage capacity is indicative of lower potential energy storage for hydrogen within the same size reservoir when compared to analogous gases, an observation that is consistent with the PVT behavior of these substances and findings from other studies (Goodman Hanson et al., 2022).

Table 5-3: Total storage potential in depleted gas fields in the U.S. Midwest for hydrogen, methane, and carbon dioxide.

U.S. Midwest Depleted Gas Field Storage Potential		
Storage Gas	**Volume Capacity (BCF)**	**Mass Capacity (MMT)**
H_2	3.76E+5	8.25E+4
Natural gas (CH_4)	4.54E+5	9.74E+5
CO_2	1.50E+6	2.99E+7

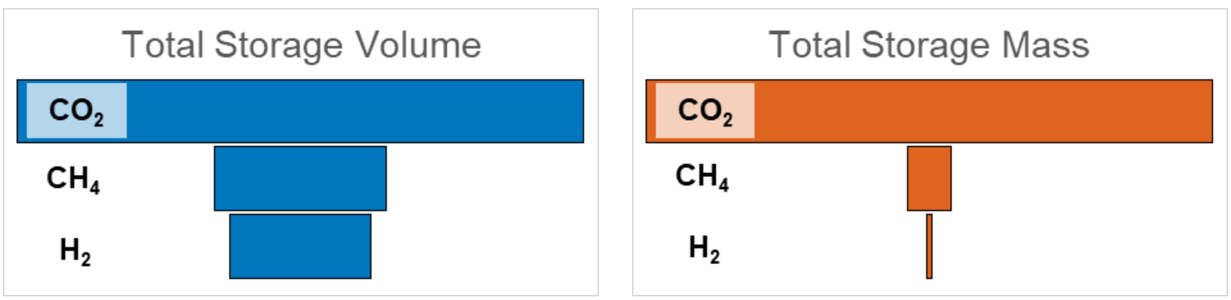

Figure 5-8: Tornado plots illustrating total storage potential in our dataset, with volume on the left and mass on the right. Size of bars correspond to the entries in Table 5-3.

Our results also explore the difference in diffusive losses between the three substances in these representative reservoir conditions. The total volume fraction lost to diffusion (that is, if every field were filled with the same substance, the fraction of stored material that would be lost) was 9.0E-5 for hydrogen, 5.5E-5 for methane, and 2.5E-4 for CO_2. The physical properties that influence diffusive losses are diffusivity and solubility. Given the difference in diffusivities between hydrogen and natural gas and their similar solubilities (see Figure 5-1), this result is expected. Diffusion appears to be significantly larger for CO_2 than for hydrogen due to its higher solubility. Given global CCS experience has sufficiently demonstrated caprock performance, this preliminary assessment thus indicates that concerns related to caprock performance are likely negligible. Note this only indicates the losses to diffusion of dissolved gas. The migration of pure-phase storage gas from these formations is likely largely absent due to their existence as reservoirs, but this loss pathway could merit further study.

The deliverability of hydrogen when compared with natural gas suggests a need to evaluate system infrastructure that will be necessary for a hydrogen economy. Because of the difference in energy densities of these substances, hydrogen pipelines will need to be equipped to transport much higher volumes of gas than are currently being transported in natural gas pipelines. UHS systems will likely need more wells per field or combined field operations to deliver the necessary quantities (by mass) of gas to meet seasonal demand. Due to the increase in hydrogen volume needed to supply equivalent energy to natural gas, it is likely that operating pressure requirements will be higher than what is typically seen in natural gas. These considerations motivate further analysis to gain a better understanding of infrastructure needs to supplement the preliminary findings from this study.

6.0 Roadmap for Commercial Hydrogen Storage in Depleted Reservoirs

6.1. Key Technology Gaps and Research Needs

Key Considerations to Accelerate UHS

This study included evaluation of summary statistics of the extensive literature review to capture the trends in hydrogen related research and industrial experience. The topics covered (using keywords to designate various aspects related to UHS) as well as the number of relevant publications were tracked and captured in Figure 6-1. Our statistical literature review (Figure 6-1) indicates that most aspects of the science of generating, capturing, transporting, and storing hydrogen are well studied.

The geology of underground hydrogen storage is actively being studied. Studies across the world cover all aspects of exploration, reservoir characterization, drilling, field development, reservoir testing, and storage monitoring to focus on understanding and optimizing the storage performance of subsurface systems. Modeling of hydrogen storage behavior over time in porous reservoirs has been one of the topics of extensive research over the last several years, and our understanding continues to improve (Tremosa et al., 2020; Abdellatif et al., 2023; Carchini et al., 2023; Delshad et al., 2022). A significant portion of them build on or extrapolate learnings from prior experience with other gases. Primary areas needing continued investigation include:

- Leakage of hydrogen through reservoir seals.
- Hydrogen-mineral interaction that may cause changes in rock character.
- Proper operating conditions for reservoirs of all types, but particularly salt caverns, depleted natural gas reservoirs, and saline aquifers.
- Injection-withdrawal cycle-induced mechanical degradation of reservoir and sealing rocks. This degradation may cause a host of issues, including weakening of seals, compaction and porosity/permeability loss in reservoirs, and loss of both pore volume and hydrogen due to compartmentalization.

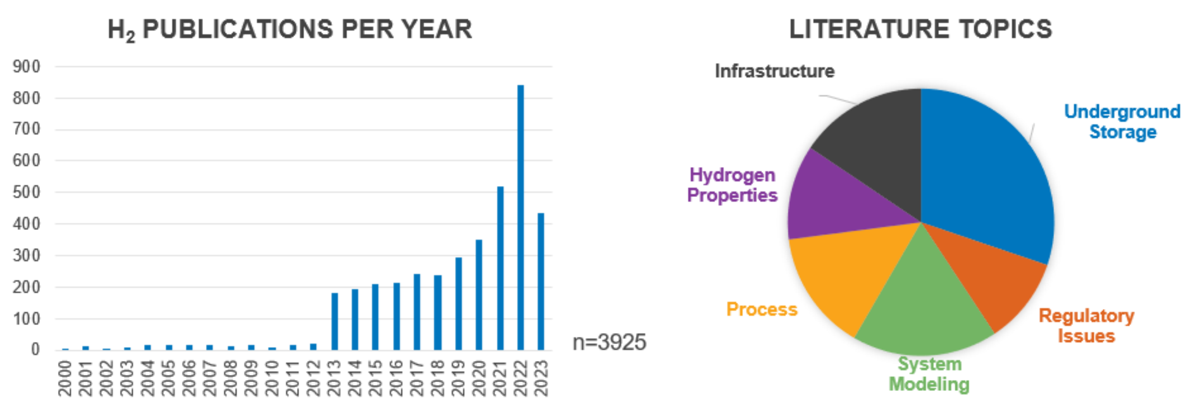

Figure 6-1: Results of statistical literature review. Publications discussing UHS and related technologies have been increasing significantly since 2013, but gaps remain in our understanding of underground hydrogen behavior and regulatory systems within the United States.

There are relatively few lab and core-based studies of the interaction between hydrogen and common subsurface constituents including rock, gas, water, oil, and microbes. This dearth of lab studies may increase uncertainty in operated reservoirs, particularly those in aquifers and layered salt formations.

Infrastructure needs for processing, compressing, transportation and usage of hydrogen also appears to be well studied. Many papers investigate applications of hydrogen as a carrier for renewable energy (Weimann et al., 2019; Sens et al., 2022; Kim et al., 2023; Liu et al., 2023), allowing energy produced by renewables to be transported in a physical form rather than through electrical infrastructure. Many other papers discuss the utility of chemical hydrogen carriers, such as ammonia, that may be able to allow for transportation of hydrogen at much higher density than in its elemental state (Aziz et al., 2020; Southall & Lukashuk, 2022). A key continuing area of research is materials science, particularly regarding materials used in tanks and pipes for surface hydrogen storage and storage well casing strings. Exposure to hydrogen can degrade both metals and cements used to ensure that wellbores do not leak, so understanding which materials will perform best over the long term will be key to reducing leakage risk during production, transport, and underground storage.

Each portion of the hydrogen supply infrastructure in the United States is regulated by international, federal, state, and local entities. A key gap appears to be the study of regulatory systems related to the production and distribution of hydrogen, particularly the interaction between federal regulations and state and local regulations. Federal regulations regarding production, storage, and transportation of hydrogen are reasonably well understood and have been clearly outlined by the DOE and other federal entities, but further guidance is needed in some areas, particularly offshore transportation (Figure 6-2, U.S. DOE, 2021b and Baird et al., 2021). Many states and municipalities are still in the process of studying and legislating around hydrogen regulation and permitting, and the interactions between federal and local regulations should become clearer over the next several years with the Hydrogen Hubs propelling significant portions of this progress.

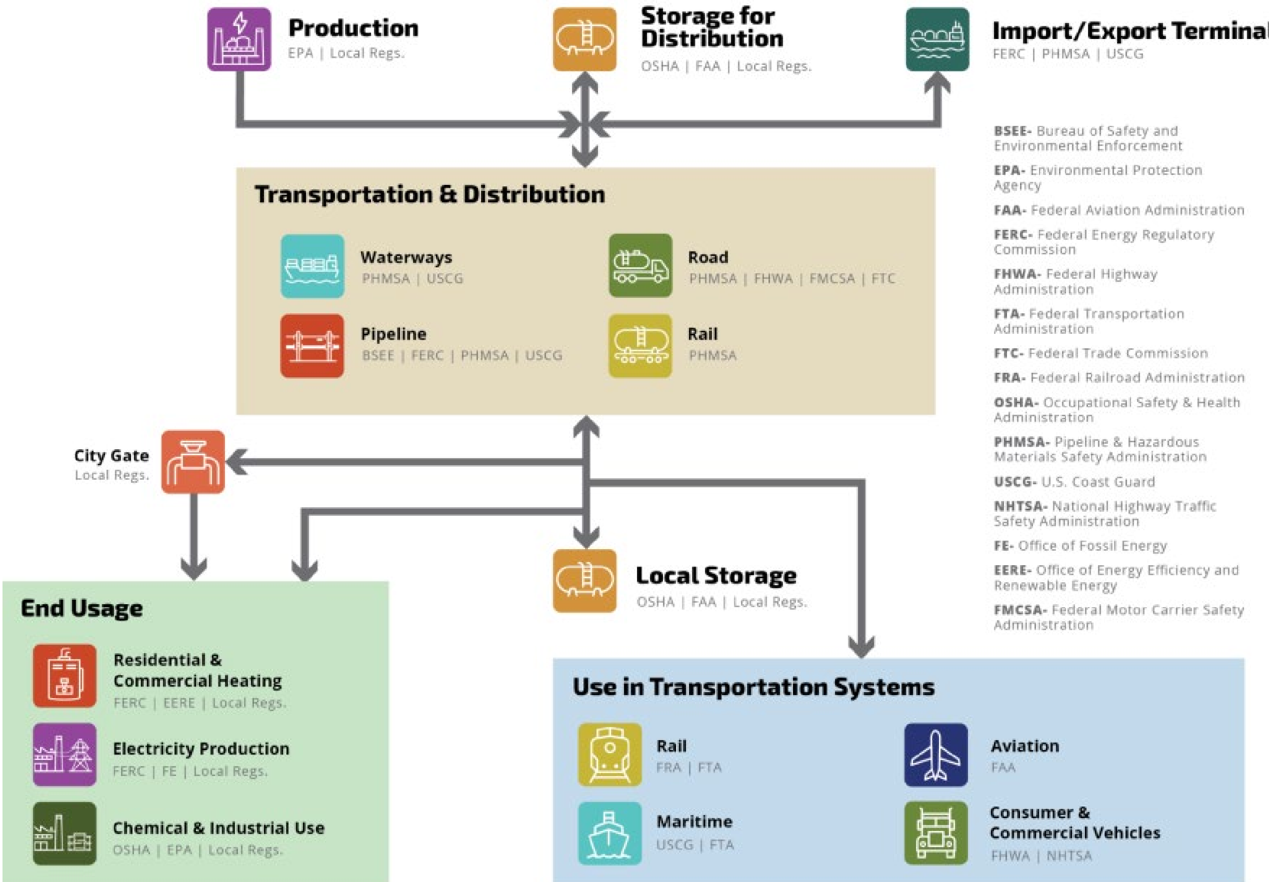

Figure 6-2: Diagram indicating organizations contributing to federal regulation of hydrogen from production to end use (Source: Baird et al., 2021).

6.2. Social Considerations

Public Awareness

Public awareness of hydrogen-based technologies is generally low, with primary awareness centered around fuel cells for bus and passenger car transport. Subsurface storage of gases has particularly low public awareness and is poorly understood by the general public: perceptions of storage reservoir depth, storage mechanism (cavern versus porous formations), leakage risk and consequences, and the sense of how ‘dangerous’ different gases are can vary widely between communities, across communities, and individually (Ricci et al., 2008; Tarkowski & Uliasz-Misiak, 2022; Gordon et al., 2023).

Public Perception

Public perception centers around both scientific knowledge and common-sense knowledge, which interact with each other. Sherry-Brennan et al. (2010) recommend focusing on science-based public outreach and common-sense-based policy engagement (Figure 6-3). Public perception is generally positive with regards to both implementation and safety, but even among people who are aware of hydrogen, neutral feelings are prevalent (Ricci et al., 2008). Perception of the cost to transition from natural gas to hydrogen for both industrial and individual (home or auto) use is generally negative, with concern that end-users will shoulder the costs of this transition. It will also be important to address the safety of hydrogen, as public concern over volatility may be a factor (Gordon et al., 2023).

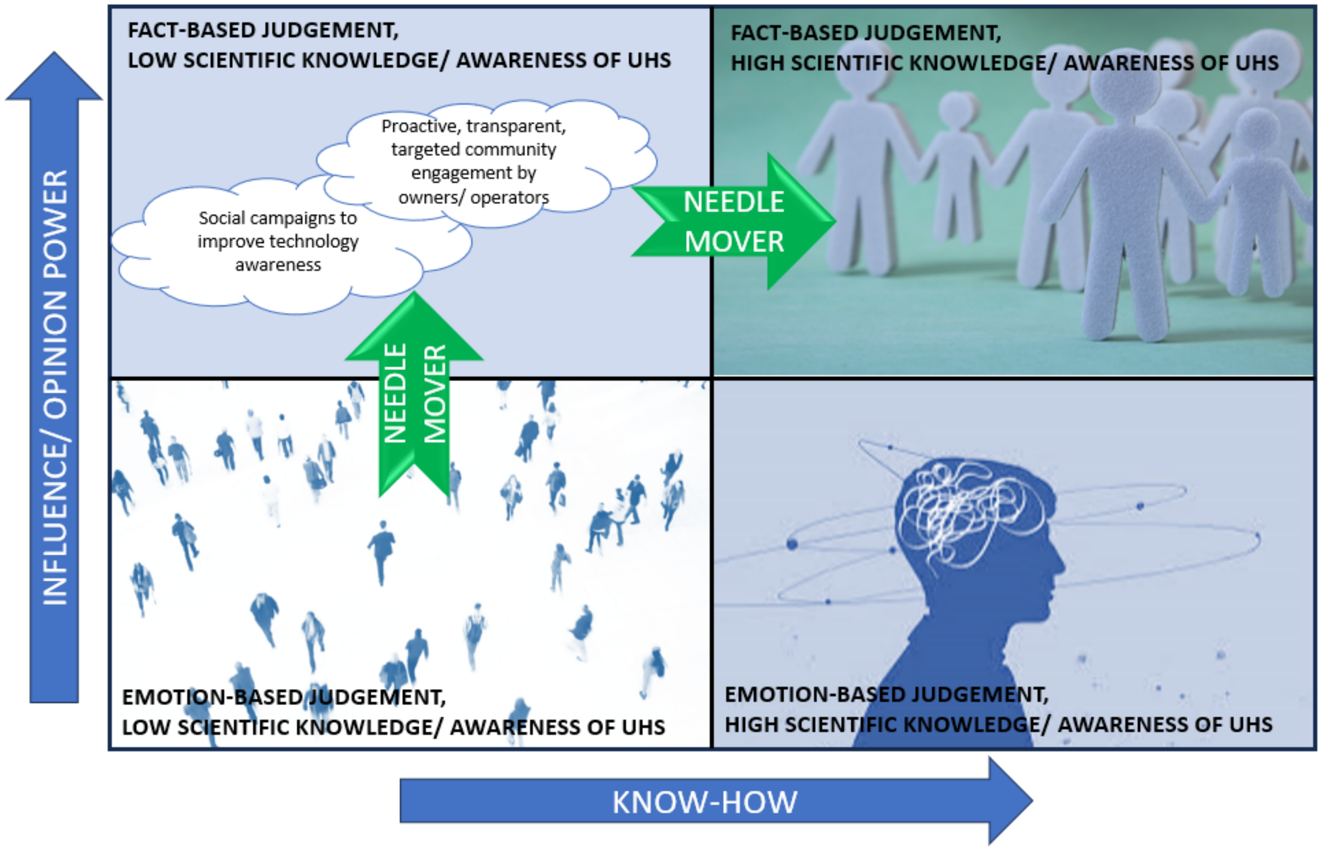

Figure 6-3: Framework for shift in public perception towards acceptance of hydrogen technologies and underground hydrogen storage.

Public Acceptance

Public acceptance of UHS has not been extensively studied to date, so the current study draws on insights from analogous geologic storage operations. Although public awareness of underground gas storage is low, studies indicate that public acceptance of underground natural gas storage is generally high (Tarkowski & Uliasz-Misiak, 2022), so by analogy to these operations, acceptance of UHS may be expected to be relatively high as well. That said, public acceptance of new technologies is heavily influenced by perception of individual and community benefit. For example, carbon storage projects have received significant push-back from local communities that view CCUS as a mechanism to further oil & gas interests at the expense of community resources and/or safety. Conversely, communities historically supported by oil and gas production may have a negative view of 'renewable' hydrogen. These communities, as well as communities experiencing energy poverty, could benefit from policies that support community ownership and decision-making (Dillman & Heinonen, 2022).

One area that is likely to be challenging is transport of hydrogen gas and/or liquids: hydrocarbon pipelines and CO_2 pipelines have received significant pushback from communities and environmental groups (Wallquist et al., 2011), and so one would expect that hydrogen pipelines will receive pushback as well. The social and environmental impacts of the development of UHS thus needs to be considered by project developers. Large quantities of hydrogen in storage or in pipelines may be seen as a danger to a community, given historical perception of hydrogen as highly flammable and explosive or an ingredient in hydrogen bombs. Examples of hydrogen-based accidents like the Hindenburg should be countered by discussion of safe, modern hydrogen handling. Community outreach will likely be necessary as a critical needle mover to bring developers and community into alignment as shown in Figure 6-3.

Impacts to Stakeholders and Environmental Justice Considerations

Hydrogen production, via its water and energy intensity, may interfere with aspects of water, energy, and climate justice. Access to clean energy and hydrogen infrastructure may be limited in regions where energy poverty is prevalent and/or water access is limited, and as the hydrogen economy grows, profit-driven export of hydrogen may exacerbate energy and water poverty for marginalized communities (Muller et al., 2022). Land use may also be a concern, particularly in areas with sensitive environments or with cultural or historical significance. Land and air quality degradation may be of concern if significant new infrastructure is needed or if trucking is part of the project's operational plan.

Potential solutions include targeted investment that enhance access for underserved communities (one potential solution is to follow guidance from the DOE Justice40 Initiative), clear regulatory control of safety so that potential incidents do not unduly impact local communities and enacting financial infrastructure that address hydrogen's potential to exacerbate energy poverty (Dillman & Heinonen, 2022). There may also be concerns of fairness, particularly where public funds are utilized to implement hydrogen mixing for home use, as many homes (particularly those in rural areas) lack connection to gas grids (Gordon et al., 2023).

There are also cultural and societal aspects to consider: there are activist groups within the U.S. and internationally that consider any project that involves the oil and gas industry or technologies associated with oil and gas to be unacceptable. UHS is likely to receive substantial negative attention from these groups, which may slow or halt project development.

Gaps

Overall, few studies of public attitudes and social justice concerning UHS are available within the U.S., revealing a significant gap. Awareness, perception, and acceptance may be significantly different within the U.S. due to its unique political, social, and educational climate, so targeted programs will be vital to domestic UHS implementation.

It is also unclear how the federal Justice40 Initiative relates to UHS projects. Justice40 implementation guidance indicates that Justice40 covers programs related to climate change, clean energy, and clean transportation, so UHS projects are likely to be covered, but are not named specifically. Federally funded efforts, including the DOE Hydrogen Hub funding, necessitate that the project developers develop and implement a Community Benefit Plan, which is tracked to encourage them to seriously consider the impact of their program on community and environmental justice and will likely lead to improved stakeholder engagement.

6.3. Economic Considerations

At the scale necessary to implement a national or global hydrogen-supported economy, UHS is more economic than most alternative storage methods (Figure 6-4), with salt caverns and depleted natural gas reservoirs representing the best combination of low risk and affordability (Figure 2-2). As emphasized in Chapter 2, salt caverns are geographically more restricted so depleted reservoirs with their high storage potential present a highly lucrative storage option. Cost and timing of pipeline development are determined to be the most significant hurdle to developing UHS infrastructure: only 1600 miles of pipeline exist within the US which are concentrated in the Gulf Coast around industrial users like chemical plants and petroleum refineries. Infrastructure build-out in other regions will need to progress rapidly and may be limited by production capacity for hydrogen-specific midstream equipment, as well as public acceptance for this new type of infrastructure (U.S. DOE, 2023). Generally speaking, current state-of-the-art UHS and associated projects being envisioned are unlikely to meet economic hurdles without subsidies like storage credits and the 45V Hydrogen Production Tax Credit.

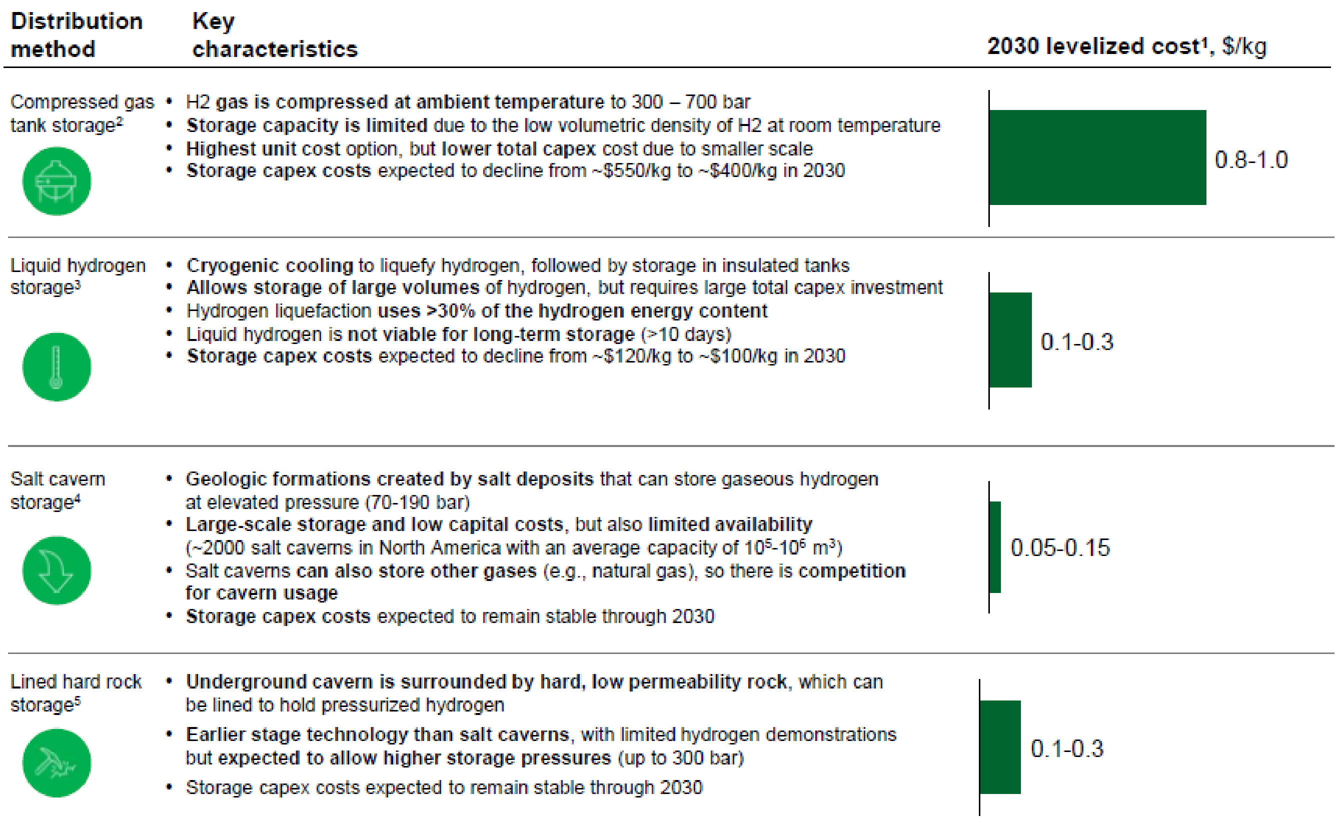

Figure 6-4: Estimated levelized cost of storage in 2030, indicating that salt cavern storage is the most affordable for high-volume, short-duration storage (Murdoch et al., 2023).

A key uncertainty for implementation of UHS in depleted reservoirs is the stability of existing wellbores over the life of UHS operations. When converting a reservoir from gas extraction to hydrogen storage, some remediation costs are to be expected during conversion, but because UHS operations introduce unique production-storage cyclicity impacts, operators should also build in remediation costs for legacy wellbores across the expected operational life of the field.

Hydrogen Workforce and Opportunities for Union Labor

Scaling up the hydrogen economy will also be challenged by the availability of a specialized workforce. The U.S. does not currently have an appropriately skilled workforce to manufacture, construct, or operate the volume of hydrogen infrastructure required to meet projected demand, so scaling this workforce presents both a challenge and an opportunity. Skillsets and labor across adjacent industries with preexisting expertise in gas handling, such as oil and natural gas, industrial gas and chemicals industries, should be engaged to source and expand the hydrogen workforce.

Opportunities for union labor must be considered throughout the entire lifecycle of a hydrogen project. Due to the similarity of the pipeline, facility, and underground storage work, UHS developers are likely to engage service providers with experience in the oil and gas industry. However, the oil and gas industry is not typically recognized as being heavily unionized. The clean energy transition may offer an opportunity to promote relationship building with unions during UHS project development. Project developers may be able to prioritize the hiring of unionized construction crews to help build the hydrogen production, pipeline, and topsides facilities, prioritize union suppliers, and use union-made products. Union apprenticeship and other training programs could be leveraged to help train the next generation of energy workers so that they are ready to go to work once completing training programs. Hydrogen project developers are encouraged to engage with labor unions and appropriate local stakeholders for relevant workforce training to facilitate smooth transition from fossil-fuel-based sectors that are expected to decline. In areas where using unionized labor is not possible (i.e. low membership due to right-to-work state, rural project area, etc.) union wages and benefits can be used as benchmarks for the workforce on hydrogen projects, thereby providing compensations that are more generous than those typically offered to non-unionized workforces.

6.4. Recommendations

Recommendations on key technological, economic, and social considerations for potential UHS projects for gas field owners/operators and energy providers interested in exploring the hydrogen-power nexus.

Over the course of this review, the scientific underpinnings of UHS in terms of the fundamental understanding of the physics of hydrogen-rock interaction and reservoir behavior during storage-withdrawal cycles is reasonably well understood. The preliminary performance assessment modeling framework completed in Chapter 4 also indicates that most reservoirs that are suitable for carbon storage operations are also suitable for hydrogen storage. Our preliminary assessment found the concerns related to caprock performance are likely less pertinent to hydrogen than they are for CO_2 storage and comparable to natural gas storage, both of which have sufficiently demonstrated storage integrity over prolonged operations. However, the subsurface presents challenges that cannot be fully addressed by lab tests and modeling, such as:

- Fault and fracture behavior is typically more complex than can be modeled
- Geomechanical and diagenetic effects on heterogeneous reservoirs and seals
- Effect of storage-production cyclicity on reservoir partitioning and reservoir & seal integrity in porous reservoirs
- Full-biome microbial interactions
- Downhole and wellbore conditions during cyclical operations
- Full-scale field tests of hydrogen handling material durability in infrastructure and facilities use cases

Field-scale demonstrations are still needed for all storage reservoir configurations discussed in Chapter 2, but particularly for depleted field storage and saline aquifer storage. Salt caverns are comparatively well understood, as there are hydrogen storage caverns in operation today, but additional tests in diverse salt mineralogies, bedded salts, and multiple subsurface stress environments would be useful. Salt storage is viewed as the lowest-risk option at the moment, with low cost to deliver, high probability of operational success, and sufficient availability of salt terrains in key industrial regions. This combination of characteristics should allow UHS to move the needle as hydrogen production ramps up. That said, depleted reservoirs are even more broadly available than salt terrains, so more focus needs to be put on de-risking these reservoirs. It will also be important to reconcile use considerations and transportation simultaneously with reservoir development, as all three aspects must be in place for success.

Primary hurdles for success for UHS projects are less likely to be technical and are more probable to be social, political, or regulatory considerations. Securing permits and rights of way for pipelines may be costly, time-consuming, and likely to be met with pushback from various communities and activist groups. As noted in the Social Considerations Section 6.2, hydrogen's flammability being perceived as a safety risk will need to be addressed before project development. We also see the likely participation of oil and natural gas companies in hydrogen projects as a potential risk in some areas, as some see hydrogen as an extension of the oil and gas industry instead of a transition.

A key recommendation for parties interested in implementing hydrogen projects, especially those with distribution and storage components, is thus to proactively begin studying and understanding the social and environmental justice aspects of their projects, conducting community education and outreach, and engagements to begin building partnerships with community leaders and environmental organizations in regions where hydrogen development is anticipated. Hydrogen developers should use insights gained by the CCUS industry as a starting point for their outreach and environmental justice approach. The CCUS industry has also been successful at implementing effective monitoring, measurement, and verification (MMV) strategies, and those learnings may also be applied to MMV for UHS.

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