



Subsurface Hydrogen and Natural Gas Storage: State of Knowledge and Research Recommendations Report

SHASTA: Subsurface Hydrogen Assessment, Storage, and Technology Acceleration Project

April 2022

Prepared for the U.S. Department of Energy, Office of Fossil Energy and Carbon Management by:

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Executive Summary

Global efforts to decrease carbon dioxide (CO₂) emissions will result in increased reliance on renewable energy sources. One of the most significant obstacles to implementing this transition is the need for energy storage to compensate for varying, and sometimes intermittent, production rates and ever-increasing demand. An attractive solution is to use surplus energy to produce hydrogen gas (H₂), which can then be used to produce energy on demand without emitting CO₂. This approach would require a vast H₂ network linking generators with consumers via transmission systems. Additionally, H₂ storage would be needed to support immediate needs, but larger storage reserves also will be required to ensure energy reliability and mitigate the impact of the mismatch between variable production rates and demand. Large-scale storage of H₂ may be achieved by using underground resources similar to how natural gas (NG) has been stored for the past century. While there is much experience in underground NG storage (UGS), significant technical challenges must be addressed to economically and safely store H₂ at the commercial scale. The purpose of this report is to assess the current state of knowledge and to identify technical research needs to facilitate deployment of large-scale underground hydrogen storage (UHS).

The three major types of UGS reservoirs – depleted hydrocarbon reservoirs, saline aquifers, and salt caverns – are also considered viable options for UHS. Other possible options include lined hard-rock caverns, coal mines, and refrigerated mined caverns. Although the majority of UGS currently occurs in depleted reservoirs, the potential need for widely distributed UHS may require use of other geologic formation types, each having advantages and disadvantages. Depleted hydrocarbon reservoirs are the lowest cost option with well-established flow and seal properties, but they may have hydrocarbon contamination issues and potential leakage risks due to existing wells. Saline aquifers have the highest potential capacity but have uncertain reservoir and seal properties. Salt caverns have the most favorable conditions for rapid storage and delivery rates, but the cost is high, the capacity is limited, and the resource is not widely distributed throughout the United States.

Although there is much experience with UGS, differences in physical properties between H₂ and CH₄ present several challenges. H₂ is lower in both mass density and volumetric energy density than CH₄, meaning that the H₂ storage volume will be larger than what is needed for CH₄ for an equivalent amount of energy content. H₂ and blended H₂/CH₄ have a lower mass density when compared to brine and pure CH₄, which leads to gravity override and increases the tendency for injected H₂ or blended H₂/CH₄ working-gas plumes to migrate upward and pond at the top of the reservoir. This may decrease the fraction of the reservoir available to store H₂ or blended H₂/CH₄ working gas while also increasing the stranding of working gas, with both effects reducing deliverability. Additionally, H₂ has a lower viscosity and higher diffusivity in water than CH₄. These differences may lead to a greater extent of viscous fingering as H₂ displaces brine within the pore space of reservoir rocks. The result would be a loss of H₂ to dissolution in the brine and would impact both storage capacity and deliverability. However, numerical studies have shown that H₂ loss due to stranding is most impactful during early injection and production cycles and decreases over time, leading to improved performance as a storage reservoir matures. Thus, operations need to be optimized using a sound technical basis to minimize the negative effects of these factors.

There are several biogeochemical reactions that could potentially interfere with storage performance and result in asset loss or operational and safety risks. Microbial processes such as sulfate reduction and iron reduction are both biogeochemical reactions that consume H₂. H₂ is generally more susceptible to these reactive losses than NG. In addition, sulfate reduction generates additional water, which could degrade the reservoir's flow performance. Iron reduction results in the precipitation of solids, which could potentially reduce the reservoir rock's porosity and permeability, leading to a decrease in capacity and

injectivity. Another potential loss of H_2 and injectivity could result from calcification, an abiotic geochemical reaction that consumes H_2 and results in mineral precipitation.

Loss of containment from the storage reservoir is possible, either through the caprock itself, through discrete faults or fractures, or through leaky wells. Diffuse leakage through caprock is expected to be greater for H_2 than NG because H_2 is a smaller molecule that more easily permeates into a low-permeability matrix. However, studies on NG leakage have found that a fault would be a more likely pathway for leakage than intact caprock. In addition, the chemical reaction between H_2 and clay minerals of a caprock can lead to swelling, which may further improve seal performance.

Previous experience with UGS has shown that the most significant risk of leakage is through loss of well integrity, either in new wells or legacy wells. There are a few documented cases where well failure has led to significant NG leakage over the past 20 years. These incidents demonstrate the need for rigorous risk mitigation strategies that include well design with redundant barriers, rigorous well evaluation programs, and continuous monitoring of well performance.

Well integrity depends on the compatibility and durability of materials used to construct and operate wells, which include steel, cement, and elastomers. Reaction of H_2 with steel has been shown to cause embrittlement and premature cracking, particularly in low-carbon steels. There is also the potential for steel corrosion induced by H_2 -consuming microbes, which produce corrosive chemicals (e.g., acids, hydrogen sulfide), directly metabolize metals, and perpetuate cathodic depolarization. Limited studies on reactivity of H_2 with cement grout suggest that damage may be negligible. Although the diffusion of H_2 into cement is not well understood, it is expected to be faster than for other gases. Elastomer well components could be damaged if H_2 penetrates the material and then rapidly decompresses within the pore structure, causing internal damage. There are elastomers that have been developed to be H_2 -resistant, but it is not well known how materials currently deployed in existing UGS facilities will perform under H_2 -rich conditions or how these new materials perform under UHS conditions.

To demonstrate storage integrity and safety for this relatively new process, real-time monitoring may be needed above the common practice at UGS sites. Sensor technology specific to monitoring UHS-relevant conditions and parameters needs to include real-time data to detect gas migration and leakage, monitor for unwanted microbial activity, and inform about the operational conditions of the reservoir.

The building of H_2 infrastructure including UHS is a major transformation that will require key stakeholder support and public acceptance. Public awareness of H_2 as an energy carrier is lacking. Early pilot demonstration projects will need to include communication strategies to increase public awareness and to limit misinformation. It is important to communicate the benefits and risks and to address stakeholder concerns.

The regulatory environment for UHS is expected to be like the current structure for UGS. Small storage fields that do not distribute gas across state lines are regulated by state public utility commissions (PUCs). Safety is regulated by each state's PUC and fire marshal, and environmental oversight is provided by a state's department of environmental protection. Larger operations are under the authority of the Federal Energy Regulatory Commission. Safety is regulated by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration, and the Environmental Protection Agency is responsible for environmental regulation. Scientific findings should be communicated to regulators to help make regulations that are protective of humans and the environment but also allow for economically attractive operations.

Recent studies have concluded that UHS is less costly than storage in above-ground vessels. Depleted NG reservoirs are generally the most cost-effective locations for UHS, largely because equipment for injection, withdrawal, and transportation is already in place.

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Acronyms and Abbreviations

AI	artificial intelligence
AZMI	above-zone monitoring interval
BCF	billion cubic feet
BCM	billion cubic meters
DEP	department of environmental protection
DOE	U.S. Department of Energy
EC	electrical conductivity
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPDM	ethylene propylene diene rubber
ERT	electrical resistivity tomography
FEPM	perfluoroelastomers
FERC	Federal Energy Regulatory Commission
FFKM	perfluorocarbon elastomer
FKM	fluoroelastomers
GCS	geological CO ₂ storage
HNBR	hydrogenated nitrile butadiene rubber
IFC	International Fire Code
IFT	interfacial surface tension
INGAA	Interstate Natural Gas Association of America
IRB	iron-reducing bacteria
LOC	loss of containment
MT	magnetotellurics
NBR	nitrile butadiene rubber
NFPA	National Fire Protection Association
NG	natural gas
PHMSA	Pipeline and Hazardous Materials Safety Administration
PUC	public utility commission
SAW	surface acoustic wave
SHASTA	Subsurface Hydrogen Assessment, Storage, and Technology Acceleration
SRB	sulfate-reducing bacteria
TDS	total dissolved solids
UGS	underground natural gas storage
UHS	underground hydrogen storage
USDW	underground sources of drinking water
VESPA	visual, environmental, socioeconomic, and procedural

Contents

Executive Summary	ii
Acknowledgments	v
Acronyms and Abbreviations.....	vi
1.0 Introduction.....	1
2.0 Subsurface Energy Storage Systems.....	5
2.1 Overview of Subsurface Storage Systems.....	5
2.1.1 Depleted natural gas (storage) fields.....	10
2.1.2 Salt caverns.....	11
2.1.3 Saline aquifers.....	11
2.1.4 Other storage options.....	12
2.2 Operational Requirements for UGS and UHS Facilities.....	13
3.0 Storage Operations and Key Risks.....	15
3.1 Deliverability Fundamentals	15
3.1.1 Energy-storage capacity	15
3.1.2 Reservoir dynamics and sweep efficiency	19
3.1.3 Relationship between UHS and UGS facility costs	26
3.1.4 Production rate/deliverability	27
3.1.5 Injection rate/deliverability	29
3.1.6 Gravity segregation of H ₂ /CH ₄ mixtures.....	31
3.1.7 Injectivity/productivity degradation (microbial, geochemical)	32
3.1.8 Engineering UHS deliverability.....	32
3.2 Asset Loss.....	34
3.2.1 Stranding	34
3.2.2 Diffuse leakage through the caprock.....	34
3.2.3 Leakage through fault zones.....	35
3.3 Subsurface Microbiology Fundamentals	36
3.3.1 Sabatier reaction (hydrogenotrophic methanogenesis).....	37
3.3.2 Hydrogen sulfide production.....	37
3.3.3 Microbiological corrosion pathways/redox reactions.....	38
3.3.4 Secondary effects.....	38
3.3.5 Future work/unknowns.....	39
3.4 H ₂ Interactions with the Storage Formation and Caprock.....	39
3.5 Downstream End-Use Factors Determining H ₂ /CH ₄ Ratios for Economic Recovery	40
4.0 Well Integrity	42
4.1 Potential Impacts of Hydrogen Leakage.....	42
4.2 Well Integrity Incidents.....	44

4.3	Durability of Well-Construction Materials under H ₂ -storage Conditions	45
4.3.1	Integrity of steel alloys.....	46
4.3.2	Integrity of wellbore cementation.....	47
4.3.3	Integrity of elastomers and seals	49
5.0	Surveillance and Monitoring	51
5.1	Surveillance and Sensors for Operational Safety	51
5.2	Monitoring for Groundwater Protection	53
5.3	Surface-Based Geophysical Monitoring Methods.....	54
5.3.1	Magnetotellurics and electrical resistivity tomography	54
5.3.2	Gravity and seismic reflection	55
5.4	Downhole Monitoring of Chemistry and Pressure.....	56
5.5	Hydrogen Seismicity Monitoring.....	57
6.0	Social License to Operate for Subsurface Hydrogen Storage.....	58
6.1	Overview	58
6.2	Current Perception of Underground Storage of Hydrogen.....	58
6.2.1	Lessons learned from analogous industries	59
6.3	Opportunities to Improve Perception and Acceptance	60
6.3.1	Business and regulatory setting.....	61
7.0	Recommendations	65
8.0	References.....	67

Figures

Figure 1.1.	Schematic showing underground storage of H_2 in depleted reservoirs, brine aquifers, salt caverns, and hard rock caverns in association with power generation and hydrogen production.	2
Figure 2.1.	Distribution of existing UGS storage fields (blue circles with white outlines), NG transmission pipelines (blue lines), and proximity to major population densities (shaded from yellow to orange).	5
Figure 2.2.	Spatial distribution of geologic units with possible storage potential and location of existing natural gas storage facilities (colored circles): a) oil and gas fields and depleted field natural gas storage facilities; b) hard rock outcroppings; c) sedimentary basins and aquifer natural gas storage facilities; d) salt deposits and salt dome natural gas storage facilities. Modified from Lord et al., Tarkowski, and Zivar et al.” and natural gas storage facility data from the U.S. Energy Information Administration (https://atlas.eia.gov/apps/natural-gas/explore). Note that currently Hawaii does not have any natural gas storage sites and its unique geology would require state-specific research and development to estimate its underground storage potential. Alaska has five natural gas storage fields around the Kenai Peninsula and could be an attractive location for underground gas storage, but ideally would be located close to population centers.....	6
Figure 2.3.	Breakdown of 672 UGS facilities operating worldwide in 2016 by region (a), working-gas volumes by region (b), and working-gas volumes by storage type (c), based on data from CEDIGAZ and Amid et al. · CIS stands for the Commonwealth of Independent States.	8
Figure 3.1.	Proportions of the bulk rock filled with H_2 or H_2/CH_4 working gas are shown for both the unswept and swept portions of the storage formation occupied by working gas for (a) 100% H_2 , (b) an 80/20 H_2/CH_4 mix by volume, and (c) a 50/50 H_2/CH_4 mix by volume. Volumetric energy density, based on bulk-rock volume in both the unswept and swept portions of the storage formation occupied by working gas, is shown for (c) 100% H_2 , (d) an 80/20 H_2/CH_4 mix by volume, and (e) a 50/50 H_2/CH_4 mix by volume. All cases assume a sweep efficiency of 50% and an irreducible water saturation, S_{wi} , of 20%.....	16
Figure 3.2.	Mass density [ρ_{H_2} and ρ_{CH_4}] (a) and volumetric energy density of H_2 and CH_4 (b), on a per gas-volume basis, are plotted as a function pressure and temperature. The volumetric energy densities of H_2 and CH_4 on a per gas-volume basis are used to determine EH_2 and ECH_4 in Equations (3.1) and (3.2), which are on a per bulk-rock volume basis.....	17
Figure 3.3.	The H_2 -to- CH_4 mass-density ratio (a) and H_2 -to- CH_4 volumetric energy-density ratio (b) are plotted as a function of pressure and temperature. The H_2/CH_4 -to- CH_4 volumetric, energy-density ratio (c) and the H_2 energy fraction in the H_2/CH_4 gas mixture (d) are plotted for different H_2/CH_4 mixtures by volume as a function of pressure for temperatures of 25 and 100 °C. Note that for (c), if 100% CH_4 were plotted, it would have a ratio of 1.....	18
Figure 3.4.	(a) The solubility of H_2 in water is plotted as a function of pressure, temperature, and the molality of water. (b) The diffusion coefficients of H_2 , CO_2 , and CH_4 are plotted as a function of temperature for atmospheric pressure.....	19

Figure 3.5.	The dynamic viscosity of water (a), dynamic viscosity of H ₂ and CH ₄ (b), gas-to-water mobility ratio for H ₂ and CH ₄ (c), and H ₂ -to-CH ₄ viscosity ratio (d) are plotted as a function of pressure and temperature.....	21
Figure 3.6.	The H ₂ /CH ₄ gas-to-water mass-density ratio for various H ₂ /CH ₄ gas mixtures by volume is plotted as a function of pressure for reservoir temperatures of 50 °C (a) and 100 °C (b).	21
Figure 3.7.	The mass-density ratios between CH ₄ and various H ₂ /CH ₄ mixtures by volume are plotted for 100% H ₂ (a), 80/20 H ₂ /CH ₄ mix (b), 50/50 H ₂ /CH ₄ mix (c), and 20/80 H ₂ /H ₄ mix (d) as a function of pressure and temperature.	23
Figure 3.8.	Gas-to-water interfacial tension (IFT) for H ₂ and CH ₄ (a), H ₂ -to-CH ₄ , gas-to-water IFT ratio (b), and H ₂ -to-CH ₄ , gas-to-water viscosity/IFT ratio (c) are plotted as a function of pressure from 0 to 250 bar and for temperatures of 25 (or 27) °C, 50 °C, and 80 °C.....	25
Figure 3.9.	Total volumetric energy density (a), H ₂ /CH ₄ -to-CH ₄ volumetric, energy-density ratio (b), CH ₄ -to-H ₂ /CH ₄ volumetric, energy-density ratio (c), and H ₂ energy fraction in the H ₂ /CH ₄ gas mixture (d) are plotted as a function of volumetric H ₂ percentage for pressures from 50 to 300 bar and temperatures of 25 and 100 °C. A temperature of 25 °C is typical for wellbore conditions, while 100 °C is representative of some reservoir conditions.	26
Figure 3.10.	Hysteretic capillary-pressure curves (a) for gas-water systems, based on Figure 6 from Zivar and others. Hysteretic relative-permeability curves (b) for water-gas systems, based on Figure 1a from Fatemi and Sohrabi.....	28
Figure 3.11.	Volumetric energy density of H ₂ /CH ₄ mixtures for pressures of 100 and 200 bar and a temperature of 50 °C (a) and buoyancy driving force increase compared to 100% CH ₄ for 200 bar and 50 °C (b). The increase in buoyancy driving force is similar for 100 and 200 bar. Note that the H ₂ /CH ₄ mixtures are on a per volume basis.....	33
Figure 3.12.	H ₂ mass fraction in the H ₂ /CH ₄ mixture is plotted as a function of volumetric H ₂ percentage (a) and volumetric H ₂ percentage is plotted as a function of H ₂ mass fraction (b) in the H ₂ /CH ₄ mixture for pressures from 50 to 300 bar and temperatures of 25 and 100 °C.....	33
Figure 3.13.	Cartoon showing how potential microbial activity can affect subsurface energy storage through hydrogenotrophic methanogenesis, hydrogen sulfide production, corrosion pathways and redox reactions, and secondary microbiological corrosion pathways.....	37
Figure 3.14.	Schematic highlighting hydrogen and natural gas storage in the subsurface at the pore scale.....	40
Figure 4.1.	Cross sectional diagram of a H ₂ storage injection well. The three major well components susceptible to integrity issues are shown: steel embrittlement, elastomer degradation, and cement diffusion.....	46
Figure 6.1.	Map showing the existing natural gas infrastructure [pipelines (purple lines) and subsurface storage facilities (purple filled circles)] and the hydrogen production potential from 100% utilization of fossil and nuclear energy sources (shaded regions in gray) binned by county. Data sources: https://www.eia.gov/maps/layer_info-m.php ; https://maps.nrel.gov/hydra/	59
Figure 6.2.	Map showing the existing natural gas infrastructure [pipelines (purple lines) and subsurface storage facilities (purple filled circles)] and the hydrogen production potential from wind, solar, biomass, and hydropower (shaded regions in green)	

binned by county. Data sources: https://www.eia.gov/maps/layer_info-m.php;
<https://maps.nrel.gov/hydra/> 60

Tables

Table 1.1.	Summary of cushion gas percentages, injection period, and withdrawal period of natural gas for the three types of UGS. Note that data was unavailable for hard rock cavern storage.....	3
Table 1.2.	Estimates of demonstrated peak and design capacity of underground working NG storage. Note that volumes are converted from billion cubic feet (BCF) to billion cubic meters (BCM).....	3
Table 1.3.	Estimates of design capacity of underground working NG storage categorized by field type. Note that volumes are converted from BCF to BCM. Data was unavailable for hard rock cavern storage.	4
Table 2.1.	High-level summary of the features of each site across the United States.”	7
Table 3.1.	Definition of terms in Equations (3.1) and (3.2) to calculate the H ₂ and CH ₄ energy content per volume of rock that is occupied by the H ₂ /CH ₄ working-gas mixture.....	16
Table 3.2.	Summary of energy content in blended H ₂ /CH ₄ gas mixtures by volume.....	19
Table 3.3.	Dynamic viscosity of H ₂ /CH ₄ mixtures by mass.	22
Table 3.4.	Range of measured gas-to-water interfacial tension (IFT) for H ₂ and CH ₄ . Also included are the calculated gas-to-water H ₂ -to-CH ₄ IFT ratio and H ₂ -to-CH ₄ viscosity to IFT ratio over indicated range of pressure and temperatures (Figure 3.8).....	24
Table 3.5.	Summary of injection/withdrawal conditions for various simulation studies.....	29
Table 3.6.	Summary of cushion-gas costs for various cushion-gas options, assuming (1) a typical cost for H ₂ produced by steam methane reforming and water-gas shift, (2) a typical cost for N ₂ , and (3) NG priced at \$4.32 per million BTU.....	30
Table 3.7.	The range in H ₂ mass fraction is listed for various values of volumetric H ₂ percentage for pressures from 50 to 300 bar and temperatures from 25 to 100 °C.	34
Table 4.1.	Comparison of the physical and chemical properties of hydrogen (H ₂), methane (CH ₄), carbon dioxide (CO ₂), nitrogen (N ₂), ethane (C ₂ H ₆), and water (H ₂ O).	43
Table 5.1.	Existing representative H ₂ sensors compared to emerging sensor technologies.....	52

1.0 Introduction

Efforts to reduce atmospheric CO₂ emissions have led to renewable energy technologies being developed and deployed to meet current and future energy demands. As a result, renewables comprise an increasing proportion of the total energy supply. In 2020, for example, renewable energy sources that include wind, hydroelectric, solar, biomass, and geothermal energy produced nearly 21% of all the electricity generated in the United States. One of the most significant challenges to continuing this change is dealing with intermittent supply and varying demand. Managing this challenge requires a means to store large amounts of energy to be readily available when demand is high. One method to overcome this challenge is to convert energy to hydrogen (H₂) gas.

H₂ as a fuel source has long been identified as a critical step toward a low-carbon, and eventually zero-carbon, energy society.^{1,2,3,4,5} H₂ has many benefits, can be generated by well-established and emerging technologies,^{6,7,8} and can be used in a variety of end-use energy and transport processes.^{9,10} Large-scale geological H₂ storage (i.e., underground hydrogen storage, UHS) offers the capacity to balance inter-seasonal supply/demand discrepancies, de-couple energy generation from demand, and decarbonize heating and transportation, thus supporting decarbonization of the entire energy system.

To advance the H₂ economy, there is a critical need to increase its availability across the United States. The development of a robust supply chain is a significant capital investment, especially for a product with far-reaching distribution needs and special handling requirements. Safe and efficient storage capabilities are integral to this supply chain and critical for price stability and our nation's energy security and independence. A significant gap is the ability to economically and safely store large amounts of H₂, much like how natural gas (NG) is stored today.

UHS is not a new concept and has been commercially demonstrated at scale in underground salt caverns, and international projects have shown this as a feasible option for existing underground natural gas storage (UGS) fields in porous and permeable reservoirs.^{11,12} These storage sites could be easily integrated into the energy system via pipelines, like the NG system. Figure 1.1 presents an illustration of potential hydrogen storage sites and how they might integrate into the power generation system. While the gas storage concept is not new, the impacts to reservoirs, H₂ leakage risks, and flow behavior of H₂ and blended mixtures are not well understood. The new demand for widely available H₂ sources and the opportunity to use H₂ blended with NG will require reservoirs distributed across the United States. The use of existing NG storage reservoirs (inherently valuable to utilities and currently providing stable

¹ J. Andrews and B. Shabini, *Where does hydrogen fit in a sustainable energy economy?*

² D.D. Peng et al., "Enabling utility-scale electrical energy storage by a power-to-gas energy hub and underground storage of hydrogen and natural gas."

³ DOE, *Department of Energy Hydrogen Program Plan*.

⁴ C. Dolan, "Road map to a US hydrogen economy."

⁵ J. Ennis-King et al., *Underground storage of hydrogen: Mapping out the options for Australia*.

⁶ Peng et al.

⁷ R. Tarkowski, "Underground hydrogen storage: Characteristics and prospects."

⁸ D. Zivar et al., "Underground hydrogen storage: A comprehensive review."

⁹ Andrews and Shabini

¹⁰ DOE

¹¹ D. Pudlo et al., "The H2STORE Project: Hydrogen Underground Storage – A Feasible Way in Storing Electrical Power in Geological Media?"

¹² S. Bauer et al., "Quantifying induced effects of subsurface renewable energy storage."

energy delivery to population centers) requires a sound technical basis for understanding operational risks before any field-scale testing could commence.

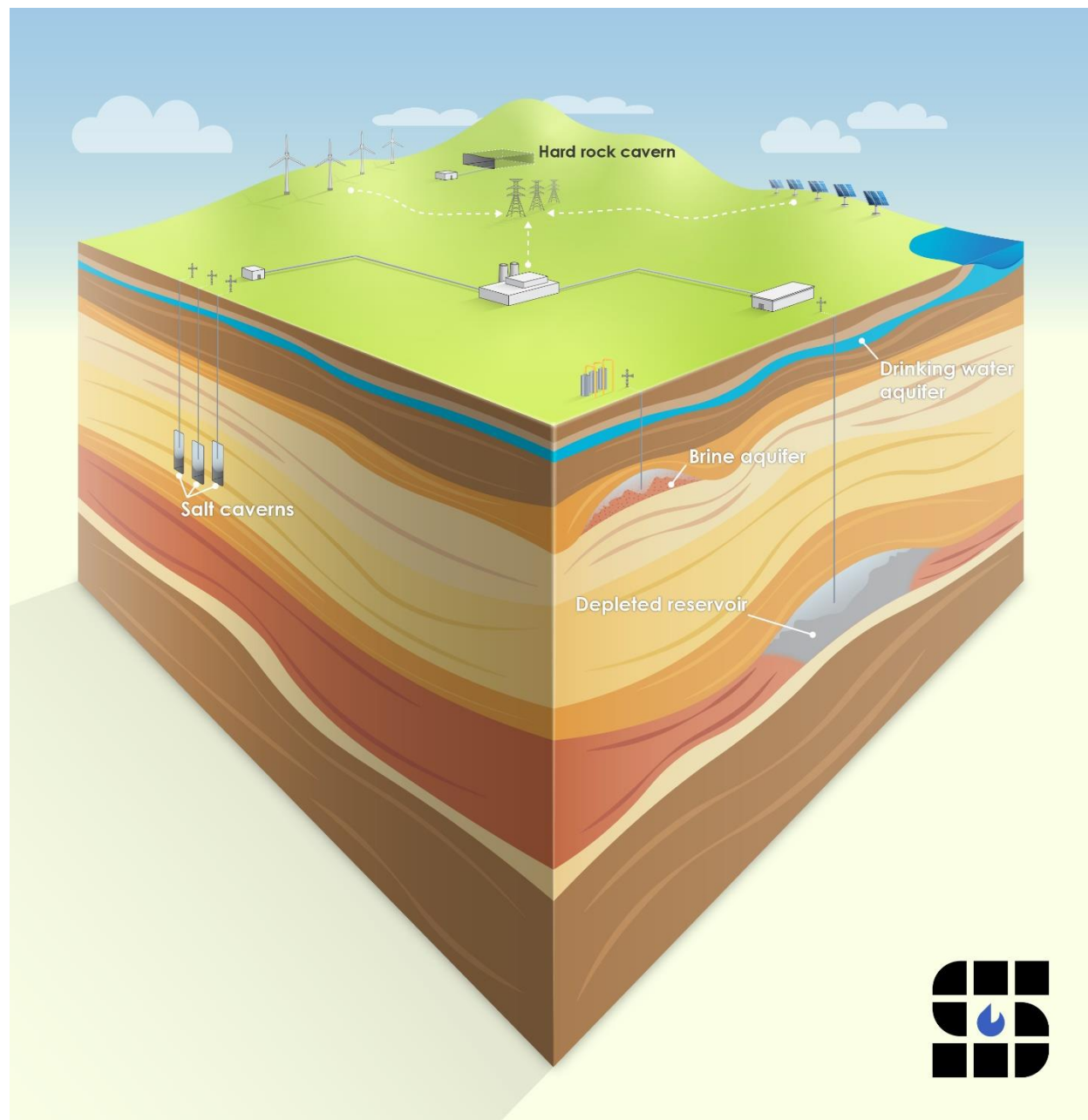


Figure 1.1. Schematic showing underground storage of H₂ in depleted reservoirs, brine aquifers, salt caverns, and hard rock caverns in association with power generation and hydrogen production.

NG has been stored in North America for more than a hundred years in salt caverns, aquifers, and depleted oil/gas reservoirs. Typically, a UGS site is operated to address seasonal variability in the demand for NG. For storage in aquifers and depleted oil/gas reservoirs, the injection period usually occurs from April through October and withdrawal usually occurs from November through March.¹ Table 1.1 summarizes

¹ FERC, *Current State of and Issues Concerning Underground Natural Gas Storage*.

typical injection and withdrawal periods for UGS fields in brine aquifers, depleted oil/gas reservoirs, and salt caverns. These fields are attractive early candidates for H₂ storage because they (1) are available throughout the U.S., (2) have substantial storage capacity, and (3) in some cases, have already been demonstrated to be suitable for UHS. Additionally, UGS fields may be able to continue being used for their original purpose if blended H₂/CH₄ gas can be separated at the surface; this concept would require research and development advancements that reduce the cost of separating H₂ and CH₄ in blended streams. Depleted oil/gas reservoirs have the advantages of (a) the demonstrated ability to prevent the vertical migration of buoyant and pressurized fluids and (b) existing well-field infrastructure, both of which may significantly reduce risk and initial capital investment. However, the introduction of H₂ as a new component in these reservoirs will introduce new challenges that will require research and development advancements to understand and address.

Table 1.1. Summary of cushion gas percentages, injection period, and withdrawal period of natural gas for the three types of UGS.¹ Note that data was unavailable for hard rock cavern storage.

Field type	Cushion gas percentage of total gas stored	Injection period (days)	Withdrawal period (days)
Brine aquifers	50–80%	200–250	100–150
Depleted oil/gas reservoirs	50%	200–250	100–150
Salt caverns	20–30%	20–40	20–40

The U.S. Energy Information Administration (EIA) tabulates the storage capacity of NG UGS in the contiguous 48 states (Table 1.2), broken down by demonstrated peak capacity and design capacity. The demonstrated peak capacity, or total demonstrated maximum working gas capacity, is sum of the highest storage inventory level of working gas observed in each distinct UGS reservoir during the previous 5-year period as reported by the operators on EIA, Form EIA-191, Monthly Underground Gas Storage Report.² The design capacity, sometimes called nameplate capacity, is based on the physical characteristics of the UGS reservoir, installed equipment, and operating procedures at a UGS site, which must often be certified by federal or state regulators. The design capacity is the theoretical limit of the total amount of NG that can be stored and withdrawn for use. As with the demonstrated peak capacity, the design capacity is reported by UGS operators on Form EIA-191.³ Table 1.2 lists the calculated demonstrated peak capacity and design capacity on the basis of the active 387 UGS fields in the Lower 48.⁴ The design capacities of active UGS sites categorized by field type (i.e., depleted field, salt cavern, or aquifer) are listed in Table 1.3.

Table 1.2. Estimates of demonstrated peak and design capacity of underground working NG storage.⁵ Note that volumes are converted from billion cubic feet (BCF) to billion cubic meters (BCM).

Region	Demonstrated peak capacity (BCM)		Design capacity (BCM)	
	Dec 2014-Nov 2019	Dec 2015-Nov 2020	Nov 2019	Nov 2020
East	27.96	28.05	30.14	30.14
Midwest	33.37	33.56	34.55	34.55
Mountain	7.39	7.56	13.36	13.33
Pacific	11.43	10.47	11.86	11.86
South Central	40.44	40.72	43.44	43.58
Contiguous 48	120.59	120.36	133.35	133.46

¹ FERC

² EIA, “Underground natural gas working storage capacity.”

³ EIA

⁴ EIA

⁵ EIA

Table 1.3. Estimates of design capacity of underground working NG storage categorized by field type.¹
 Note that volumes are converted from BCF to BCM. Data was unavailable for hard rock cavern storage.

Field type	Design capacity (BCM)	
	Nov 2019	Nov 2020
Brine aquifers	11.32	11.31
Depleted reservoirs	110.33	110.4
Salt caverns	13.68	13.80
Total	135.33	135.51

¹ EIA

2.0 Subsurface Energy Storage Systems

2.1 Overview of Subsurface Storage Systems

UGS sites are distributed throughout the United States and are often located near large urban centers, where NG demand is greatest (Figure 2.1). A typical gas storage complex consists of a reservoir composed of layers of porous and permeable rock that contain the gas, an overlying caprock that prevents vertical migration of fluids, and a system of wells used to inject and produce the gas. Use of these fields enables continued supply of NG to maintain a constant base supply, accommodate peak energy demand, and suppress price volatility. These fields are attractive early candidates because they have substantial storage capacity, and in some cases have already been demonstrated to be suitable for hydrogen storage. Additionally, UGS fields may be able to continue being used for their original purpose if blended H_2/CH_4 gas could be separated at the surface; this concept would require research and development advances that reduce the cost of separation technologies.

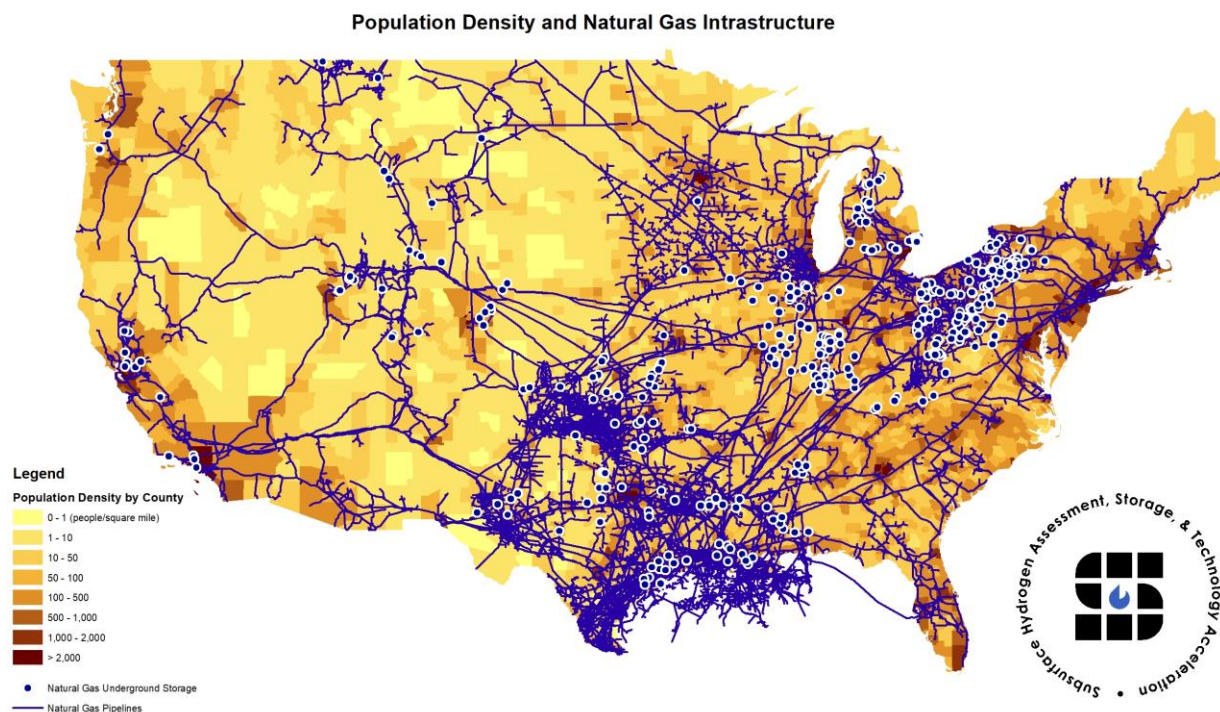


Figure 2.1. Distribution of existing UGS storage fields (blue circles with white outlines), NG transmission pipelines (blue lines), and proximity to major population densities (shaded from yellow to orange).

Currently, the three main types of UGS in service are depleted oil and gas fields, saline aquifers, and salt caverns; other options being considered are lined hard-rock caverns, abandoned coal mines, and refrigerated mined caverns. In this study, we focus on depleted oil and gas fields, saline aquifers, and salt caverns, and lined hard-rock caverns. Technology for abandoned coal mines and refrigerated mined caverns, while not considered here, is being evaluated as prospective storage sites for NG storage. Figure 2.2 highlights the spatial distribution of geologic units with storage potential. Table 2.1 identifies pros and cons for the main geologic storage types. NG has been stored in North America for over a hundred years, with depleted oil

and gas fields as the preferred reservoir type.¹ The additional options may be adopted in regions where the three main types of UGS are not available.² Today, there are more than 460 UGS fields across the U.S., ranging in storage capacity from less than 0.03 BCM to greater than 1.5 BCM.³

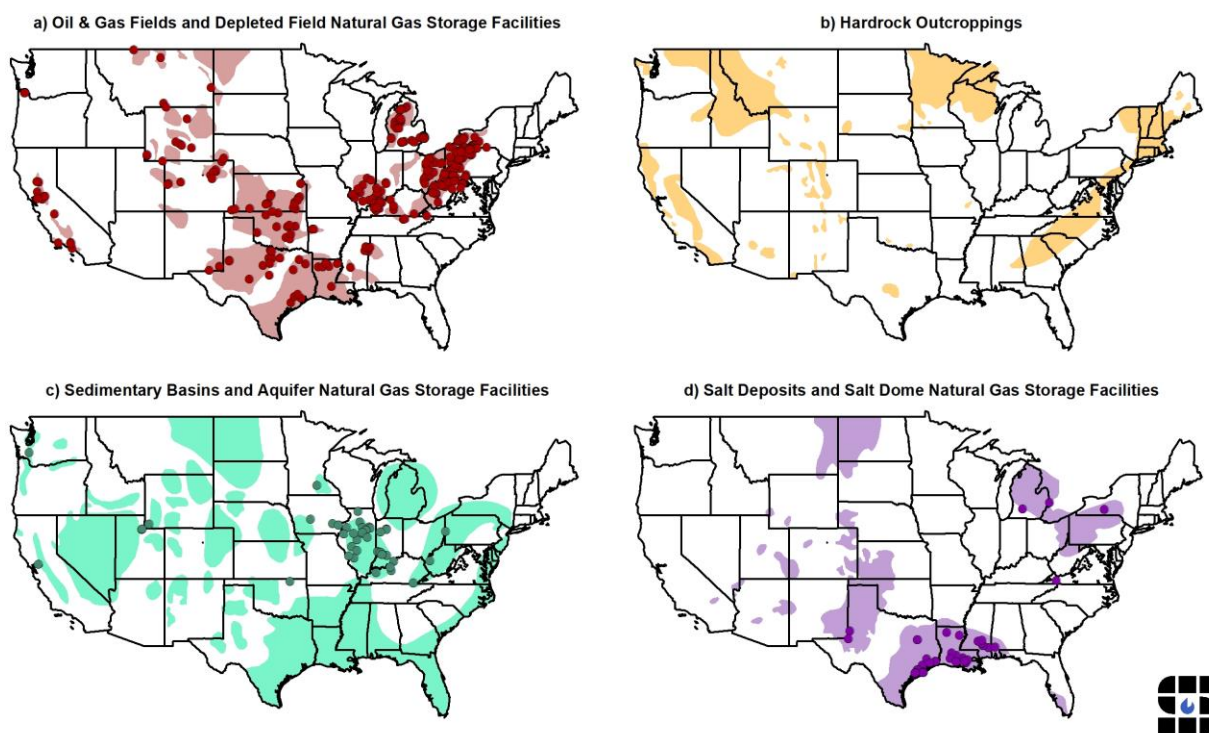


Figure 2.2. Spatial distribution of geologic units with possible storage potential and location of existing natural gas storage facilities (colored circles): a) oil and gas fields and depleted field natural gas storage facilities; b) hard rock outcroppings; c) sedimentary basins and aquifer natural gas storage facilities; d) salt deposits and salt dome natural gas storage facilities. Modified from Lord et al., Tarkowski, and Zivar et al.^{4,5,6} and natural gas storage facility data from the U.S. Energy Information Administration (<https://atlas.eia.gov/apps/natural-gas/explore>). Note that currently Hawaii does not have any natural gas storage sites and its unique geology would require state-specific research and development to estimate its underground storage potential. Alaska has five natural gas storage fields around the Kenai Peninsula and could be an attractive location for underground gas storage, but ideally would be located close to population centers.

¹ D. Vikara et al., *Underground Natural Gas Storage – Analog Studies to Geologic Storage of CO₂*.

² A.S. Lord et al., “Geologic storage of hydrogen: Scaling up to meet city transportation demands.”

³ EIA

⁴ Lord et al.

⁵ Tarkowski, “Underground hydrogen storage: Characteristics and prospects.”

⁶ Zivar et al.

Table 2.1. High-level summary of the features of each site across the United States.^{1,2,3}

Geologic Storage Formation Type	Opportunities	Challenges
Depleted oil and gas fields	<ul style="list-style-type: none"> • Large potential storage volume • Demonstrated to trap buoyant fluids • Established favorable flow and seal properties • Existing wells may be repurposed for storage • Characterization data likely available from previous activity • Lowest cost option • Bring back value from a brownfield site • Additional hydrocarbon recovery • Mature technology for conversion to natural gas storage operations 	<ul style="list-style-type: none"> • Depletion <i>may</i> have impacted seal competency, storage capacity, and/or gas deliverability • Infrastructure (wells, pipelines) may not be suitable or may be degraded • Legacy wells may be leakage pathways • Hydrocarbon “contamination” may be deleterious to storage operations • May not support fluctuating load demands • Likely regionally constrained • Technology is immature for H₂ storage when significant oil is present
Operational natural gas storage fields	<ul style="list-style-type: none"> • Existing infrastructure may be suitable • Piping to power plants and electricity generation in some markets • Well-characterized site containing all features for economic gas storage • Mature technology for conversion to natural gas storage operations 	<ul style="list-style-type: none"> • May damage an active asset • Existing demand for the natural gas contained in the field • Likely regionally constrained • Technology is under development for H₂ storage in existing operational fields
Saline aquifers	<ul style="list-style-type: none"> • Largest lateral availability and possible capacity • Fewer or no legacy wells to cause leakage risk 	<ul style="list-style-type: none"> • Uncertain reservoir and sealing properties • Highest cost option • May not support fluctuating load demands • Limited previous experience, so technology is immature
Salt caverns	<ul style="list-style-type: none"> • Likely low leakage risk • Shallow resource • Relatively rapid storage/delivery rates, excellent candidates for peak load • Previous demonstrated success with H₂ storage • Fewer wells required • Technology is mature 	<ul style="list-style-type: none"> • Geomechanical deformation may lead to well integrity issues • Likely regionally constrained • Technology is demonstrated at field scale
Hard rock caverns and mines	<ul style="list-style-type: none"> • Might be a good option for regions without viable alternatives • Likely rapid storage/delivery rates and an excellent candidate for peak loads 	<ul style="list-style-type: none"> • Likely regionally constrained • Technology is immature

¹ Lord et al.² Tarkowski, “Underground hydrogen storage: Characteristics and prospects.”³ Zivar et al.

Multicomponent flow behavior for blends of H₂ and NG in UGS fields must be reevaluated when using the field to store any fluid. Establishing and maintaining a reservoir with a sufficiently high fluid flow rate is necessary to economically store and retrieve the commodity. Use of existing UGS facilities removes a significant technical hurdle because the system has demonstrated the ability to permit timely injection and production of the resource. However, the blending of H₂ into an NG stream raises several technical questions and imposes a new critical constraint to not damage the existing UGS resource from the introduction of H₂.

Compared to above-ground storage facilities, UGS facilities have several advantages^{1,2,3}:

- **Storage safety:** Because the containment vessel is a geologic formation that is physically separated from risk factors, such as O₂, ignition sources, and floods, subsurface storage is less susceptible to fire, extreme climate events, and sabotage.
- **Surface footprint:** Subsurface storage requires less land than is required for surface storage tanks.
- **Costs:** Construction costs are much less than with surface tanks because the geologic structure is the containment vessel.
- **Suitable geological structures:** Subsurface storage reservoirs are widely available worldwide.

Between 2015 and 2016, the number of UGS facilities in operation worldwide declined from 680 to 672 (Figure 2.3a) because several were mothballed, while working-gas capacity increased from 413 to 424 BCM (Figure 2.3b), with the volumes distributed over three primary storage types (Figure 2.3c)^{4,5}. Most (94%) of the NG storage capacity is in three developed markets: North America (161 BCM, or 38%), Commonwealth of Independent States (127 BCM, or 30%), and the European Union (106 BCM, or 25%).

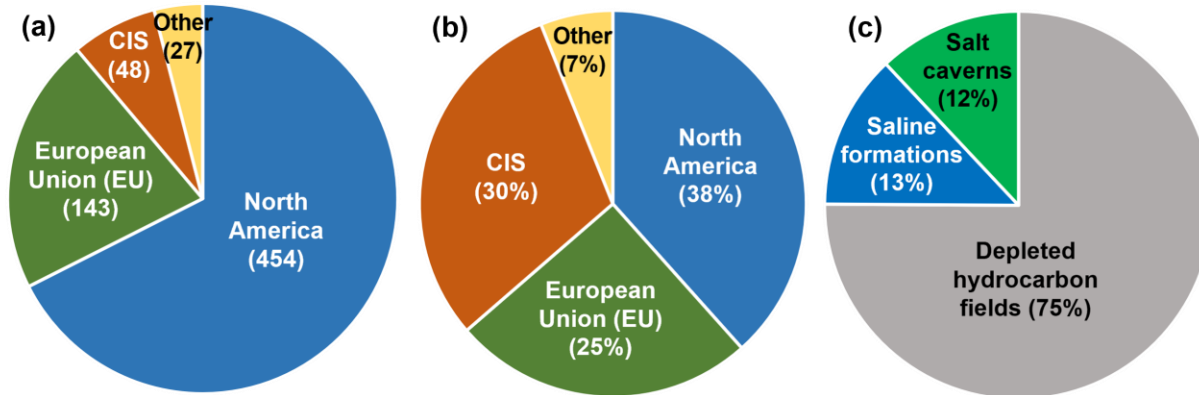


Figure 2.3. Breakdown of 672 UGS facilities operating worldwide in 2016 by region (a), working-gas volumes by region (b), and working-gas volumes by storage type (c), based on data from CEDIGAZ and Amid et al.^{6,7} CIS stands for the Commonwealth of Independent States.

¹ R. Tarkowski, "Perspectives of using the geological subsurface for hydrogen storage in Poland."

² R. Tarkowski, and G. Czapowski, "Salt domes in Poland - Potential sites for hydrogen storage in caverns."

³ Tarkowski, "Underground hydrogen storage: Characteristics and prospects."

⁴ CEDIGAZ, "Underground gas storage in the world – Part 1: Current capacity."

⁵ A. Amid et al., "Seasonal storage of hydrogen in a depleted natural gas reservoir."

⁶ CEDIGAZ

⁷ Amid et al.

Field experience with subsurface H₂ storage is scarce and is mainly limited to salt cavern storage, primarily at Teesside, UK; Clemens Dome, USA; and Moss Bluff, USA and more recently in Beaumont, USA.^{1,2} Salt caverns are poor analogs to storage in UGS fields. There is a stronger connection to H₂ storage with applications that involve town gas storage such as at Beynes, France, and Lobodice, Czech Republic.³ Town gas is a mixture of hydrogen, methane, and nitrogen (25-60% H₂, 10-33% CH₄, 12-20% CO + CO₂, and <30% N₂).⁴ Studies have shown that gas composition evolves during the storage cycle, with a reduced share of H₂ and increased share of CO₂ and CH₄.^{5,6,7} One mechanism for this change could be increased microbial activity; another is that the higher mobility and lower density of H₂ leads to *in situ* gas redistribution. All mechanisms must be carefully managed to meet reservoir performance goals.

An additional technical aspect for operators to study when considering the conversion of an existing UGS facility to one that stores H₂ or H₂/CH₄ gas mixtures is the volumetric energy density, which is strongly dependent on depth and temperature and is progressively lower as the H₂/CH₄ blend approaches pure H₂. At a 1-km depth and temperature of 50 °C, the volumetric energy density of pure H₂ is only 26.1% that of pure CH₄.⁸

In porous reservoirs, gaseous H₂ will dissolve into the reservoir fluids (oil, water, gas) until equilibrium is reached. It will affect the capital expenditure as the dissolved gas will be a one-time loss that will continue to accumulate during the early injection/withdrawal cycles until the liquid reservoir fluids are saturated with H₂. The diffusion and dissolution of H₂ into the caprock fluids will be slower than in the reservoir. That slow diffusion and dissolution process will continue to result in H₂ losses until the adjacent caprock is saturated with H₂. For porous UGS reservoirs, H₂ losses on the order of 2% have been reported over the life cycle of a UGS storage operation.⁹ From a capital-cost perspective, rather than treating this as a loss of H₂, it could be regarded as part of the cushion-gas investment.

Other mechanisms for gas loss are leakage through the caprock, which is generally insignificant unless the caprock integrity has been compromised; dissolution into connate water; diffusion in surrounding brine; and contamination with pre-existing hydrocarbons.¹⁰ Gas losses can also result through fingering with the surrounding reservoir brine, which can be a problem when the injected gas is more mobile than the native brine being displaced. Such instability between gas and brine can cause gas to travel down the structure and become unrecoverable.¹¹ Numerical modeling has indicated that injecting an aqueous foam into a reservoir can help control the migration of gas from the designated gas-storage area. When the foam is injected just above the gas-brine interface, it can help limit the coning of brine up into the withdrawal wells.¹²

¹ Tarkowski, "Underground hydrogen storage: Characteristics and prospects."

² J. Mouli-Castillo et al., "Mapping geological hydrogen storage capacity and regional heating demands: An applied UK case study."

³ Bauer et al.

⁴ M. Panfilov, "Underground and pipeline hydrogen storage."

⁵ F. Feldmann et al., "Numerical simulation of hydrodynamic and gas mixing processes in underground hydrogen storages."

⁶ B. Hagemann et al., "Multicomponent gas rising through water with dissolution in stratified porous reservoirs - Application to underground storage of H₂ and CO₂."

⁷ B. Hagemann et al., "Hydrogenization of underground storage of natural gas."

⁸ Amid et al.

⁹ NEA, *The effects of hydrogen injection in natural gas networks for the Dutch underground storages*.

¹⁰ P.O. Carden, and L. Paterson, "Physical, chemical and energy aspects of underground hydrogen storage."

¹¹ Carden and Paterson

¹² P. Persoff et al., "Aqueous foams for control of gas migration and water coning in a quifer gas storage."

Capillary, or residual, trapping – where H_2 is rendered immobile in the pore space as disconnected ganglia, surrounded by brine in a storage aquifer – is controlled by fluid and interfacial physics at the size scale of rock pores. For H_2 loss through the caprock, capillary trapping will play an important role. Because the caprock is saturated with brine, caprock sealing is assisted by capillary pressure, which should not be exceeded. The influence of H_2 (versus CH_4) on capillary pressure has not been reported yet – it is assumed that it depends on the interfacial tension between water and H_2 , which is similar to that between CH_4 and water.

2.1.1 Depleted natural gas (storage) fields

By their nature, depleted oil and gas reservoirs have already demonstrated the ability to seal and prevent the vertical migration of fluids. Their use may also significantly reduce initial capital investment given their existing well networks. However, the introduction of a new component (H_2) to the UGS reservoir may introduce new and poorly understood hazards. The principal hazards of converting a UGS field into a blended H_2 /NG system result from changes to fluid transport processes and new biogeochemical interactions associated with H_2 .

Depleted hydrocarbon reservoirs have been the most prominent and commonly used reservoir type for UGS to date. These reservoirs are typically located thousands of feet underground, where most of the recoverable product has been extracted. Generally, UGS fields located in depleted hydrocarbon fields are easy to develop, operate, and maintain due to the existing infrastructure. NG stored in depleted hydrocarbon reservoirs is intended to meet base load needs and is generally cycled once a year during the winter season. Depleted oil/gas are preferred because they have a structural trap, such as anticlinal structural with a proven ability to securely store pressurized, buoyant fluids. Depleted NG fields are typically preferred to oil reservoirs because a large amount of gas may be lost due to chemical reactions with residual oil.^{1,2}

The experience gained from storing NG and CO_2 in depleted hydrocarbon fields helps with evaluating the technical and geological requirements for a geological structure to qualify as a potential UHS site. The reservoir should be thick, porous, and permeable to provide sufficient capacity to store the required H_2 volume and injectivity to take in the gas at an acceptable rate.³ Additionally, the reservoir should be capped by a low-permeability caprock to prevent gas from migrating or leaking from the storage unit. While sandstone and carbonate rocks are appropriate for a gas reservoir, low-permeability shale and evaporites usually serve as adequate confining layers. Anticline structures are particularly suitable for storing a high-mobility gas such as H_2 because they better confine the gas plume to a limited area.⁴ Depleted hydrocarbon fields naturally meet these requirements given that they have already proven to be efficient fluid traps through geologic time. Still, care should be taken when selecting a depleted deposit for H_2 storage because the reservoir might have continuously lost gas over geologic time or it might do so once operating pressure increases.⁵ Depleted hydrocarbon fields have been the preferred geologic storage for UGS. Of the 672 working UGS facilities worldwide in 2016, 74% were depleted fields,⁶ accounting for 80% of working gas volumes.

¹ Tarkowski, “Underground hydrogen storage: Characteristics and prospects.”

² Zivar et al.

³ S. Bachu, “ CO_2 storage in geological media: role, means, status and barriers to deployment.”

⁴ A. Sainz-Garcia et al., “Assessment of feasible strategies for seasonal underground hydrogen storage in a saline aquifer.”

⁵ Lord et al.

⁶ CEDIGAZ

Lord et al. compared the costs of developing and operating H₂ underground sites for four types of geologic sites and concluded that depleted deposits are the most economically attractive option.¹ Another opportunity to reduce costs is related to the need for injecting cushion gas, which is a major cost driver. To maintain reservoir pressure and adequate withdrawal rates, at least 50% of the stored gas must function as cushion gas, with the rest being working gas (Table 1.1). However, once a producing reservoir is abandoned, the reservoir will still contain quantities of hydrocarbons and brine. The NG left in place can contribute to the cushion gas requirement,² especially when the gas extraction from the depleted reservoir has been stopped at an optimum time.³ Hydrocarbon exploration in such areas has also contributed to the geological and engineering knowledge of these fields as robust data sets have been generated over the years. A potential risk to injection/withdrawal operations is the existence of legacy wells with unknown integrity. Legacy wells are the greatest source of potential leakage during UGS operations.

2.1.2 Salt caverns

Caverns can be operated under variable or constant pressures.⁴ Under variable-pressure operations, approximately one-third of the cavern volume will contain cushion gas, with the rest being working gas.⁵ As working gas is withdrawn, the pressure decreases and the required amount of cushion gas is determined by the minimum pressure required to prevent salt creep and maintain cavern integrity.⁶ To operate under constant pressure, brine is withdrawn at the same volumetric rate as gas injection and is injected at the same volumetric rate of gas withdrawal. Cushion gas is not needed under these operating conditions.^{7,8} This concept works well in the closed container of a salt cavern. Permeability tests with different gases (CH₄, CO₂, and N₂) have shown that the permeability of rock salt formations is very low, within the range of 10⁻¹⁷ to 10⁻²¹ m².⁹

For UHS in salt caverns, the primary capital costs are associated with construction of the caverns by dissolution and the cost of cushion gas for facilities that allow variable storage pressure. The cost of an injection/withdrawal borehole is anticipated to be much greater than it is with UGS because of the added expense of materials that are resistant to H₂ embrittlement, which is not an issue with UGS.

2.1.3 Saline aquifers

Saline aquifers are more expensive to develop than depleted hydrocarbon reservoirs due to lack of infrastructure and characterization costs needed to address uncertain geology and reservoir properties. Characterization efforts, including well testing, are needed to determine whether structural trapping is sufficient to seal and contain stored gas.¹⁰ Characteristics of ideal gas traps include structural highs, such as anticlines; low caprock permeability; and sufficient hydrostatic pressure.¹¹ Additional investments will be

¹ Lord et al.

² S. Foh et al., *Underground Hydrogen Storage*.

³ Tarkowski, "Underground hydrogen storage: Characteristics and prospects."

⁴ Foh et al.

⁵ K.L. Beckman et al., "Natural gas storage: Historical development and expected Evolution: December 1994-February 1995."

⁶ Foh et al.

⁷ Foh et al.

⁸ J.B. Taylor et al., "Technical and economic-assessment of methods for the storage of large quantities of hydrogen."

⁹ NEA

¹⁰ Beckman et al.

¹¹ Foh et al.

required for the wells and above-ground infrastructure, including pipelines, gas compressors, and a gas dehydration facility.¹

Cushion gas requirements for saline aquifers are greater than those for depleted hydrocarbon reservoirs. The required cushion-gas volume may be as high as 80% of the total reservoir volume.² Unlike depleted hydrocarbon reservoirs, aquifers lack pre-existing gas in place to offset the cushion-gas needs. As with depleted hydrocarbon reservoirs, gas losses are inevitable. Gas losses must be compensated for because inadequate cushion gas can lead to reservoir damage.³

2.1.4 Other storage options

2.1.4.1 Limestone reservoirs

There are a few UGS facilities in limestone reservoirs, such as the Adrian and Thomas Corners fields, both located in Steuben County, New York. The Thomas Corners field, which uses a 53-m-thick reservoir bounded by impermeable shales, is capable of multiple cycles to meet winter and summer demands. The Rivara UGS facility is in a fractured limestone reservoir that has a large gas storage capacity capable of meeting seasonal demands. The cushion-gas requirement of the Rivara UGS field is only 14% of the reservoir capacity because it can rely on hydrostatic pressure from the underlying aquifer to support high gas withdrawal rates.⁴

2.1.4.2 Coal Mines

The use of abandoned coal mines for UGS has been limited, with two UGS facilities in Belgium and one in Colorado, which have since been decommissioned.⁵ In addition to UGS, coal mines have been considered for compressed air energy storage due to their large storage capacity and proximity to major population centers.⁶

2.1.4.3 Hard Rock Caverns and Mines

Hard rock caverns may be attractive alternatives for regions without conventional storage mechanisms or when on-site storage is critical for facility operations. Caverns can be excavated in igneous or metamorphic rock and completed as unlined or lined cavities. Liners may be plastic, steel, or cementitious grout. Depending on the facility configuration, safe storage may need to rely on hydrostatic fluid pressure or water curtains to contain the gas.⁷ The water curtain technique was developed to compensate for excavated caverns never being completely impermeable. Water curtains involve a series of horizontal boreholes surrounding an excavated cavern through which water continuously flows toward the cavern, which suppresses the loss of gas flow through fractures.⁸ The excavated caverns must be deep enough for the hydrostatic pressure to exceed the gas-storage pressure. In addition to suppressing gas losses through

¹ Foh et al.

² Beckman et al.

³ A.S. Lord, *Overview of Geologic Storage of Natural Gas with an Emphasis on Assessing the Feasibility of Storing Hydrogen*.

⁴ Independent Resources, “Re: Rivara Gas Storage.”

⁵ Lord

⁶ M. Lutyński, “An overview of potential benefits and limitations of Compressed Air Energy Storage in a bandoned coal mines.”

⁷ N.S. Muhammed et al., “A review on underground hydrogen storage: Insight into geological sites, influencing factors and future outlook.”

⁸ Lord

fractures, the water curtain can create artificially high pressures for caverns located at depths where naturally occurring hydrostatic pressure would not exceed required gas-storage pressures.¹ Another unconventional technique being proposed is to refrigerate the gas so that less storage space is required for these excavated types of storage facilities.²

2.2 Operational Requirements for UGS and UHS Facilities

Both UGS and UHS facilities are required to safely handle and contain high-pressure gas, which is highly flammable and entails explosive risk. Both UGS and UHS facilities will have a combination of surface and subsurface components designed to compress, inject, contain, withdraw, and process high-pressure gas through wells that communicate with deep reservoirs. The subsurface components include the caprock (seal) for preventing pressurized, buoyant gas from flowing upward; the overburden (rock), which adds storage security; and the well. The following is abstracted from experience with UGS facilities in California.³

UGS and UHS facilities are required to:

1. Accept gas as delivered from the transmission pipeline for injection in the reservoir.
2. Deliver high-quality gas to the distribution system as needed.
3. Safely contain high-pressure gas.

The most common UGS failures involve either a loss of containment (LOC) or damage to a well or other component that affects health and safety, the environment, or facility operations without LOC. LOC is the primary focus because UGS and UHS involve containing a gas at very high pressure through a series of multiple, repeated operations (compression, injection, storage, withdrawal, decompression, processing, pipeline transport, and utilization). LOC can be broken down to the following categories.

Loss of well integrity

- During injection/withdrawal, pressurized gas migrates through the tubing/packer, casing, or uncemented/poorly-cemented annular space, which allows gas to reach shallower aquifers, possibly breaking out as an uncontrolled release to the ground surface.
- During well work-overs or plug-and-abandon operations, the well may “kick” due to the underbalance of “kill” fluids, which may result in an immediate uncontrolled release through the well to the surface.
- For plugged and abandoned wells, failure of the mechanical plug or cement may allow gas to migrate out of the storage reservoir and enter shallower permeable formations, with potential breakout at the surface.
- Seismic activity strong enough to damage wellbores may allow uncontrolled release at the surface without the ability to shut in the well.
- Severe wellhead damage may allow for uncontrolled release without ability to shut in the well.

¹ U.E. Lindblom, “A conceptual design for compressed hydrogen storage in mined caverns.”

² Muhammed et al.

³ J. Long et al., *Long-Term Viability of Underground Natural Gas Storage in California*.

Loss of reservoir integrity

- Over-pressuring the gas-storage reservoir beyond pressure limits of confinement may allow gas to migrate into shallower, permeable formations. Leakage pathways may include fault zones or abandoned wells.
- Overfilling the gas-storage reservoir beyond the spill point of the geologic trapping mechanism may allow gas to reach additional leakage pathways.

In California, 81% of the LOC incidents are documented to be related to loss of subsurface integrity (casing, seal, well control, etc.).¹ An example of a nationally recognized case of oil and stray gas migration, called the “Bainbridge Incident,” occurred in Bainbridge Township of Geauga County, Ohio, in 2007.²

Some UGS facilities are located in regions with particular hazards that can affect UGS infrastructure, which include seismic, landslide, flood, tsunami, and wildfire hazards. The risk arising from these hazards along with monitoring, prevention, and intervention needs can be assessed in the risk management plans for each facility.

¹ Long et al.

² E.S. Bair et al., *Subsurface gas invasion Bainbridge Township, Geauga County, Ohio: Expert Panel Technical Report*.

3.0 Storage Operations and Key Risks

3.1 Deliverability Fundamentals

The deliverability of a UHS system will depend on several fundamental factors: (1) the H_2 energy content per volume of rock occupied by the H_2/CH_4 working gas; (2) sweep efficiency, which is the percentage of the storage zone occupied by the H_2/CH_4 working gas; (3) production rate during the withdrawal cycle; (4) injection rate during the injection cycle; (5) degradation of injectivity and productivity by microbial and geochemical mechanisms; and (6) asset loss, caused by stranding, microbial conversion of H_2 to less-valuable forms of energy, and leakage of the H_2/CH_4 working gas from the storage formation.

3.1.1 Energy-storage capacity

The energy-storage capacity of H_2 depends on several factors, including those influenced by (1) engineering decisions, such as the H_2 and CH_4 volume fractions in the H_2/CH_4 working gas; (2) injection rate of the working gas; (3) properties of H_2 , CH_4 , and formation brine, such as viscosity and mass density; and (4) properties of the storage formation, such as porosity and wettability. Some factors influence sweep efficiency, quantifying the swept fraction of the storage formation, which corresponds to the portion occupied by the H_2/CH_4 working gas.

The H_2 energy content per volume of rock (MJ/m^3) that is occupied by the working H_2/CH_4 gas mixture, E_{H_2} , is determined by Equation (3.1) and Table 3.1:

$$E_{H_2} = \rho_{H_2} (LHV_{H_2}) Y_{H_2} \phi (1 - S_{wi}) \quad (3.1)$$

The CH_4 energy content per volume of rock, E_{CH_4} , is given by Equation (3.2) and Table 3.1:

$$E_{CH_4} = \rho_{CH_4} (LHV_{CH_4}) Y_{CH_4} \phi (1 - S_{wi}) \quad (3.2)$$

The total energy content per volume of rock is equal to the sum of E_{H_2} and E_{CH_4} . The total volumetric energy content per volume of rock in both the unswept and swept portions of the storage formation is depicted in Figure 3.1. The volumetric energy density, on a per gas-volume basis (Figure 3.2b), is the product of mass density of H_2 or CH_4 (Figure 3.2a) and the lower heating value of H_2 or CH_4 .

Table 3.1. Definition of terms in Equations (3.1) and (3.2) to calculate the H₂ and CH₄ energy content per volume of rock that is occupied by the H₂/CH₄ working-gas mixture.

Term	Unit	Definition
E_{H_2}	MJ/m ³	H ₂ energy content per volume of rock
ρ_{H_2}	kg/m ³	Mass density of H ₂ at reservoir temperature and pressure
ρ_{CH_4}	kg/m ³	Mass density of CH ₄ at reservoir temperature and pressure
LHV_{H_2}	MJ/kg	Lower heating value of H ₂ (120 MJ/kg)
LHV_{CH_4}	MJ/kg	Lower heating value of CH ₄ (50 MJ/kg)
Y_{H_2}	fraction	Volume fraction of H ₂ in the gas phase for the working gas
Y_{CH_4}	fraction	Volume fraction of CH ₄ in the gas phase for the working gas
ϕ	fraction	Porosity
S_{wi}	fraction	Irreducible water saturation

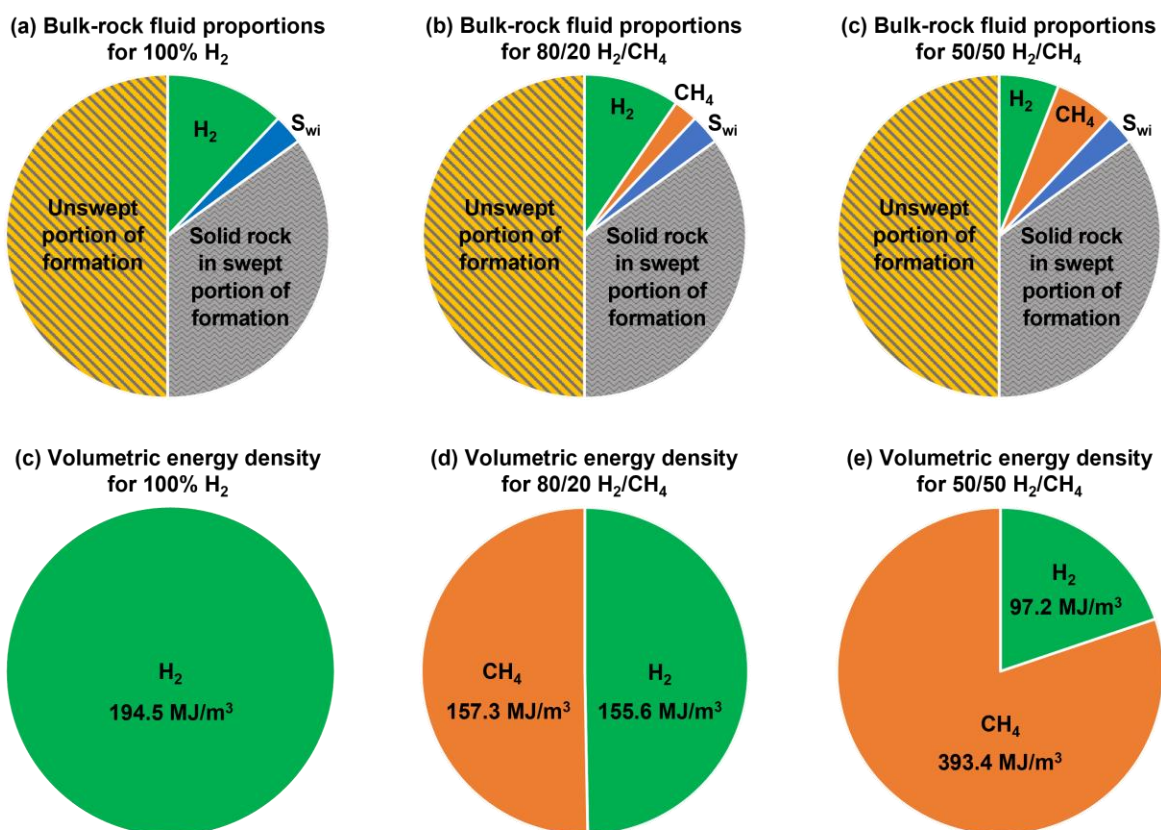


Figure 3.1. Proportions of the bulk rock filled with H₂ or H₂/CH₄ working gas are shown for both the unswept and swept portions of the storage formation occupied by working gas for (a) 100% H₂, (b) an 80/20 H₂/CH₄ mix by volume, and (c) a 50/50 H₂/CH₄ mix by volume. Volumetric energy density, based on bulk-rock volume in both the unswept and swept portions of the storage formation occupied by working gas, is shown for (d) 100% H₂, (e) an 80/20 H₂/CH₄ mix by volume, and (f) a 50/50 H₂/CH₄ mix by volume. All cases assume a sweep efficiency of 50% and an irreducible water saturation, S_{wi} , of 20%.

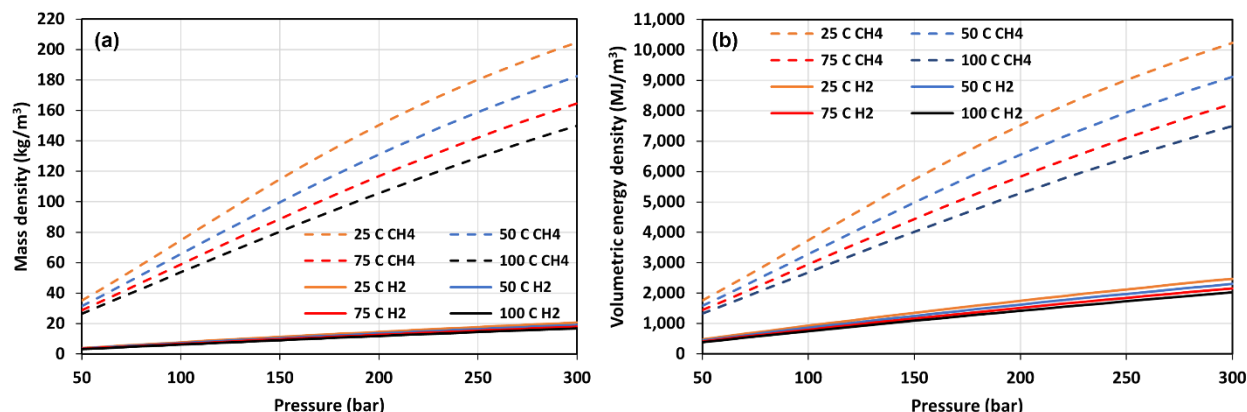


Figure 3.2. Mass density [ρ_{H_2} and ρ_{CH_4}] (a) and volumetric energy density of H₂ and CH₄ (b), on a per gas-volume basis, are plotted as a function pressure and temperature. The volumetric energy densities of H₂ and CH₄ on a per gas-volume basis are used to determine E_{H_2} and E_{CH_4} in Equations (3.1) and (3.2), which are on a per bulk-rock volume basis.

It is important to note that Equations (3.1) and (3.2) are applicable to the swept portion of the storage formation occupied by the H₂/CH₄ working gas versus the unswept portion of the storage formation that is bypassed by the injected H₂/CH₄ working gas, due to viscous fingering and buoyancy flow (also called gravity override as discussed in this section and in Section 3.1.2). The influence of gravity segregation of H₂/CH₄ gas mixtures, which is different from gravity override, is discussed in Section 3.1.5. The swept portion of the storage formation occupied by the H₂/CH₄ working gas is determined by sweep efficiency, discussed in Section 3.1.2. Note that Equations (3.1) and (3.2) are applicable to steady-state conditions, after initial H₂ losses have occurred, such as those caused by H₂ dissolution into formation brine (see Figure 3.4a), methanogenesis, sulfate reduction, iron reduction, and calcification (see Section 3.1.7). Most of these loss mechanisms will affect H₂ storage during the early injection/withdrawal cycles and should dissipate as conditions in the working-gas zone have equilibrated.

The mass density of H₂ is much less than that of CH₄, with the minimum H₂-to-CH₄ mass-density ratio occurring at a pressure of 180 bar and a temperature of 25 °C (Figure 3.3a), which is a temperature applicable to wellbore conditions during injection. Temperatures of 50 to 100 °C are applicable to reservoir storage conditions. The H₂-to-CH₄ mass-density ratio decreases with pressure (for $P < 180$ bar) and increases with pressure (for $P > 180$ bar). The H₂-to-CH₄ mass-density ratio also increases with temperature. Because the lower heating value of H₂ (120 MJ/kg) is greater than it is for CH₄ (50 MJ/kg), the H₂-to-CH₄ volumetric energy-density ratio (Figure 3.3b) is greater than the corresponding mass-density ratio.

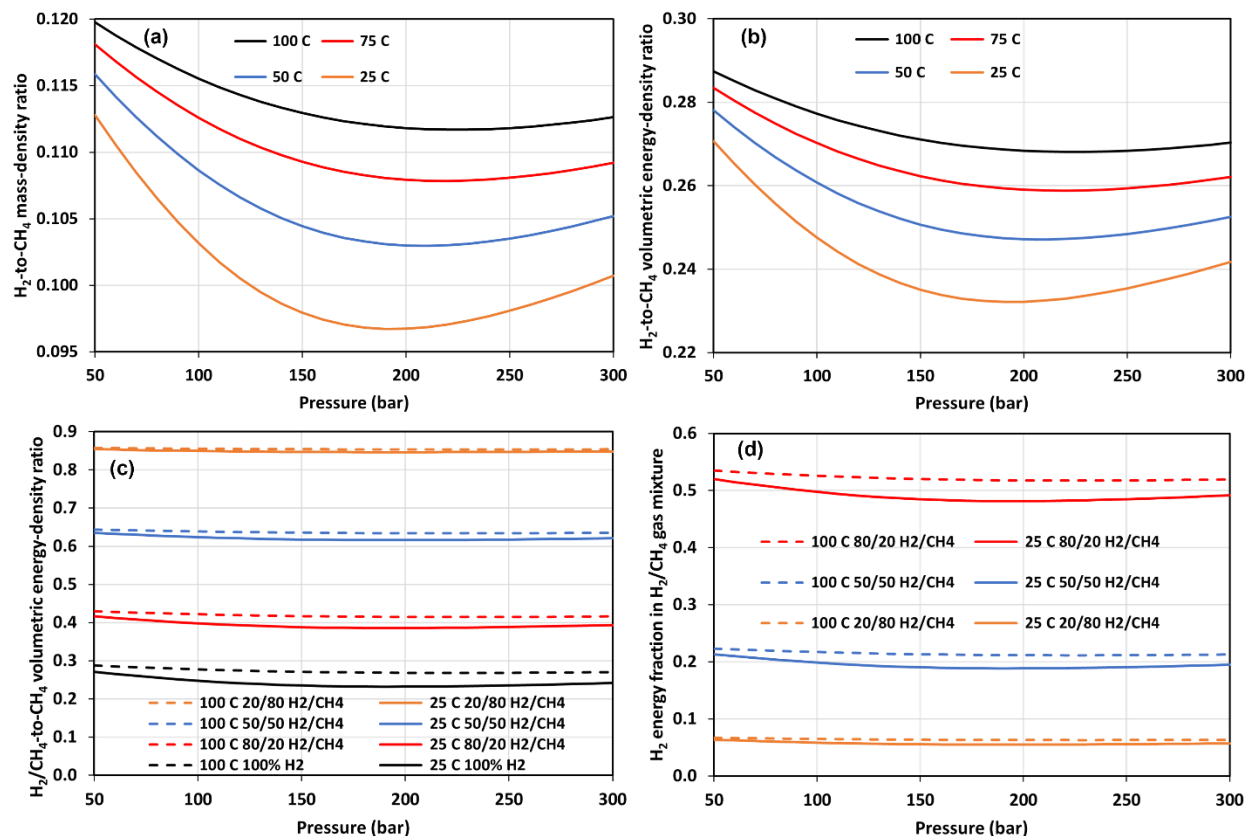


Figure 3.3. The H₂-to-CH₄ mass-density ratio (a) and H₂-to-CH₄ volumetric energy-density ratio (b) are plotted as a function of pressure and temperature. The H₂/CH₄-to-CH₄ volumetric, energy-density ratio (c) and the H₂ energy fraction in the H₂/CH₄ gas mixture (d) are plotted for different H₂/CH₄ mixtures by volume as a function of pressure for temperatures of 25 and 100 °C. Note that for (c), if 100% CH₄ were plotted, it would have a ratio of 1.

Because UHS will involve storing mixtures of H₂ and CH₄, it is useful to compare the volumetric, energy-density of H₂/CH₄ mixtures in UHS reservoirs to that of CH₄ in UGS reservoirs. Figure 3.3c plots the H₂/CH₄-to-CH₄ volumetric, energy-density ratio for various H₂/CH₄ mixtures, including 100% H₂ and 80/20, 50/50, and 20/80 mixtures of H₂ and CH₄. This ratio reaches a minimum at a pressure of 180 bar and increases with temperature. The H₂ energy fraction in H₂/CH₄ gas mixtures (Figure 3.3d) is a useful quantity that shows the fraction of the storage capacity in a UHS facility that can be applied to green energy.

Table 3.2 summarizes the energy content of H₂/CH₄ gas mixtures for pressures from 50 to 300 bar and temperatures from 25 to 100 °C, as plotted in Figure 3.3. A UHS facility for 100% H₂ can store 24% to 28% of the energy content of a UGS facility with the same volumetric capacity, with all of the stored energy being from H₂. A UHS facility for an 80/20 H₂/CH₄ gas mixture can store 39% to 43% of the energy content of a UGS facility, with 48% to 53% of the stored energy being from H₂. A UHS facility for a 50/50 H₂/CH₄ gas mixture can store 62% to 64% of the energy content of a UGS facility, with 19% to 22% of the stored energy being from H₂. A UHS facility for a 20/80 H₂/CH₄ gas mixture can store 85% to 86% of the energy content of a UGS facility, with 5% to 7% of the stored energy being from H₂.

Table 3.2. Summary of energy content in blended H₂/CH₄ gas mixtures by volume.

H ₂ /CH ₄ gas mixture	H ₂ /CH ₄ -to-CH ₄ volumetric energy-density ratio	CH ₄ -to-H ₂ /CH ₄ volumetric energy-density ratio	H ₂ energy fraction in H ₂ /CH ₄ gas mixture
100/0	0.24–0.28	3.69–4.31	1.0
80/20	0.39–0.43	2.40–2.59	0.48–0.53
50/50	0.62–0.64	1.57–1.62	0.19–0.22
20/80	0.85–0.86	1.17–1.18	0.05–0.07

3.1.2 Reservoir dynamics and sweep efficiency

As discussed earlier, the dissolution of H₂ into formation brine will result in some of the injected H₂ being unrecoverable (see Figure 3.4). This loss will continue until equilibrium is established between H₂ and formation brine in the zone containing the working gas. The solubility of H₂ increases weakly with temperature and strongly with pressure (Figure 3.4a). The solubility of H₂ decreases strongly with increasing molality of the formation brine (Figure 3.4a).

Several factors will influence the magnitude and duration of H₂ losses resulting from the dissolution of H₂ in formation brine. The first is the diffusivity of H₂ in water, which is nearly three times that of CH₄ and CO₂, while increasing weakly with temperature (Figure 3.4b). Limited experience with UHS provides little data for estimating such losses. Research indicates 0.4% of injected H₂ can be lost due to the dissolution of H₂ into formation brine during the first injection/withdrawal cycle.^{1,2}

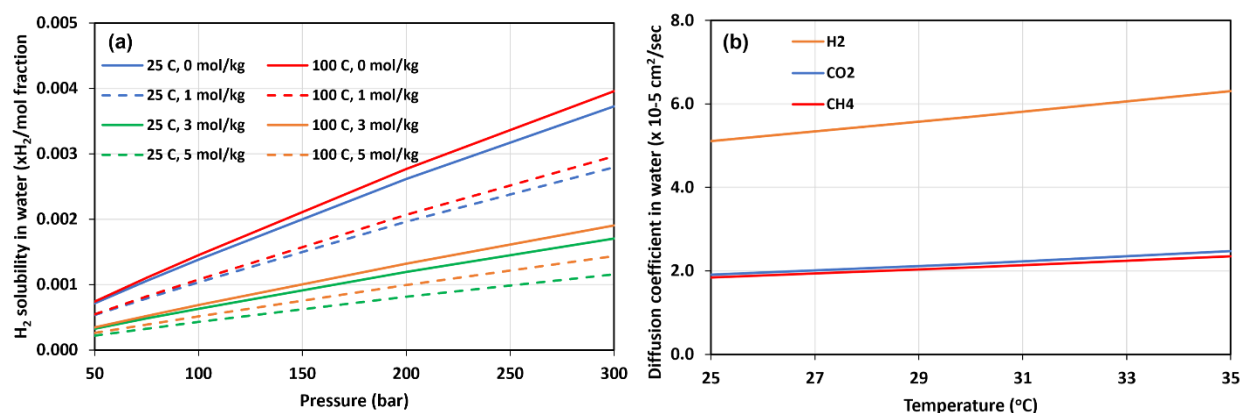


Figure 3.4. (a) The solubility of H₂ in water is plotted as a function of pressure, temperature, and the molality of water.³ (b) The diffusion coefficients of H₂, CO₂, and CH₄ are plotted as a function of temperature for atmospheric pressure.⁴

Other factors influencing H₂ losses are buoyancy-driven flow (gravity override) and viscous fingering. These factors determine how much brine is in proximity to the portion of the storage formation occupied by the H₂/CH₄ gas mixture. An experimental investigation found that H₂ fingering is strongly controlled by the H₂ injection rate.⁵ It was observed that the fingers, resulting from interface instability, tend to

¹ Carden, and Paterson

² Zivar et al.

³ S. Chabab et al., “Measurements and predictive models of high - pressure H₂ solubility in brine (H₂O+NaCl) for underground hydrogen storage application.”

⁴ ToolBox, “The Engineering ToolBox.”

⁵ L. Paterson, “The implications of fingering in underground hydrogen storage.”

spread perpendicular to the primary flow direction. The number of gas fingers propagating through the more viscous fluid has been observed to be reduced as the fingers propagate further into the viscous fluid. This is due to a phenomenon called shielding.¹ During gas fingering, the contact area between the injected H₂ and reservoir rock increases, which increases (1) H₂ dissolution into the brine, (2) H₂ diffusion within the brine, and (3) geochemical interaction between H₂ and the reservoir rock.

The viscosity of water, H₂, and CH₄ will strongly influence viscous fingering of H₂/CH₄ gas mixtures (Figure 3.5). Over the range of relevant conditions for UHS (pressure of 50 to 300 bar and temperature of 25 to 100 °C), the following observations can be made:

- The viscosity of water (Figure 3.5a), which is always greater than that of H₂ and CH₄ (Figure 3.5b), is insensitive to pressure and decreases with increasing temperature.
- The viscosity of CH₄ is always greater than that of H₂, while the viscosity of H₂ increases with pressure and temperature (Figure 3.5b).
- The viscosity of CH₄ increases with pressure, while its dependence on temperature is more complex, increasing with temperature for pressures between 50 and 170 bar and decreasing with temperature for pressures between 170 and 300 bar (Figure 3.5b).
- The gas-to-water mobility ratio for H₂ is insensitive to pressure and decreases with temperature, while for CH₄ it decreases with pressure and temperature (Figure 3.5c).
- The H₂-to-CH₄ viscosity ratio decreases with pressure and increases with temperature (Figure 3.5d).

The drivers for viscous fingering are:

- Viscosity contrast between formation brine and the H₂/CH₄ mixture, with Figure 3.5c plotting the gas-to-water mobility ratio for pure H₂ and pure CH₄.
- H₂-to-CH₄ viscosity ratio, which is important for determining the differences in sweep efficiency for H₂ and CH₄, as shown in Figure 3.5d.
- Density difference between formation brine and H₂/CH₄ mixture, which drives gravity override and is plotted as a mass-density ratio (Figure 3.6).
- Surface-tension forces, quantified by interfacial surface tension (IFT).

¹ C.K. Ho, and S.W. Webb, *Gas Transport in Porous Media, Theory and Applications in Porous Media*.

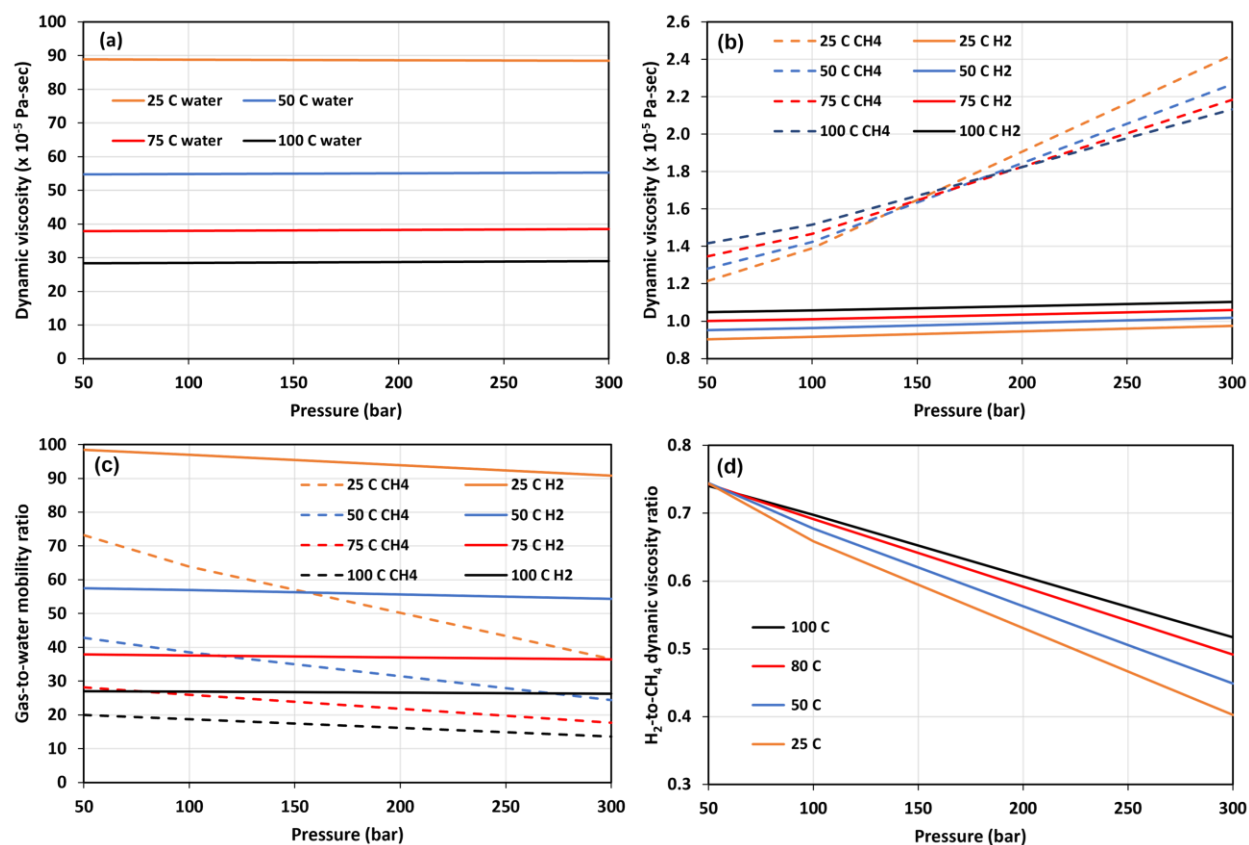


Figure 3.5. The dynamic viscosity of water (a), dynamic viscosity of H_2 and CH_4 (b), gas-to-water mobility ratio for H_2 and CH_4 (c), and H_2 -to- CH_4 viscosity ratio (d) are plotted as a function of pressure and temperature.

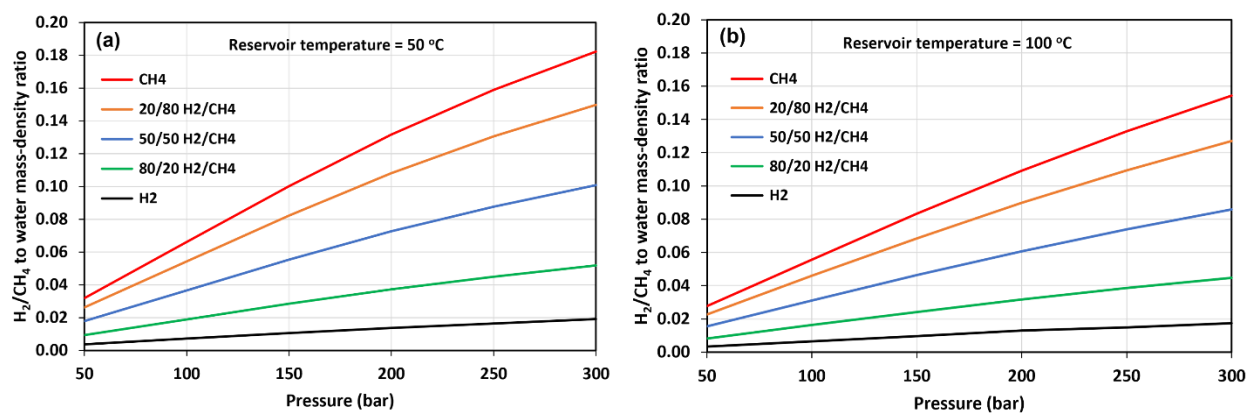


Figure 3.6. The H_2/CH_4 gas-to-water mass-density ratio for various H_2/CH_4 gas mixtures by volume is plotted as a function of pressure for reservoir temperatures of 50 °C (a) and 100 °C (b).

There is limited data for the viscosity of H₂/CH₄ gas mixtures.¹ Chuang et al. (1976) determined the viscosity for H₂/CH₄ gas mixtures for very low temperatures, below those relevant to UHS reservoirs.² For a pressure of 100 bar and temperature of -75 °C, they found that a H₂/CH₄ gas mixture with 53.37% H₂ had a dynamic viscosity of 0.011 Pa-sec (Table 3.3). For the same conditions, the H₂/CH₄ gas mixture with 19.42% H₂ had a dynamic viscosity of 0.0145 Pa-sec. For this data set, the dynamic viscosity appears to be a composition-fraction-weighted average of the H₂ and CH₄ values, using a fitting coefficient of 0.5831.

Table 3.3. Dynamic viscosity of H₂/CH₄ mixtures by mass.³

H ₂ /CH ₄ mixture	Measured dynamic viscosity (Pa-sec)	Calculated dynamic viscosity (Pa-sec)
100/0	0.0065	NA
0/100	0.0310	NA
0.5337/0.4663	0.0110	0.0105
0.1942/0.8058	0.0145	0.0153

For UGS, buoyancy-driven flow (gravity override) plays a key role in sweep efficiency. Because the mass density of H₂ is much less than that of CH₄, the influence of buoyancy will be more pronounced for UHS than it is for UGS. A measure of the relative magnitude of the buoyancy driving force for UHS, compared to UGS, is the mass-density ratio between CH₄ and the H₂/CH₄ gas mixture, which is dependent on pressure and temperature, as shown in Figure 3.7. For storage of pure H₂, the buoyancy driving force is 8.4 to 10.3 times greater than it is for CH₄ storage, depending on the pressure and temperature of the storage reservoir (Figure 3.7a). For an 80/20 H₂/CH₄ gas mixture, the buoyancy driving force is 3.4 to 3.6 times greater than it is for CH₄ storage (Figure 3.7b). For a 50/50 H₂/CH₄ gas mixture, the buoyancy driving force is 1.79 to 1.82 times greater than it is for CH₄ storage (Figure 3.7c). For a 20/80 H₂/CH₄ gas mixture, the buoyancy driving force is 1.21 to 1.22 times greater than it is for CH₄ storage (Figure 3.7d).

¹ V. Vesovic, and W.A. Wakeham, “The prediction of the viscosity of dense gas mixtures.”

² S.Y. Chuang, et al., “Viscosity of methane, hydrogen, and four mixtures of methane and hydrogen from -100 °C to 0 °C at High Pressures.”

³ A.E. Yekta et al., “Evaluation of geochemical reactivity of hydrogen in sandstone: Application to geological storage.”

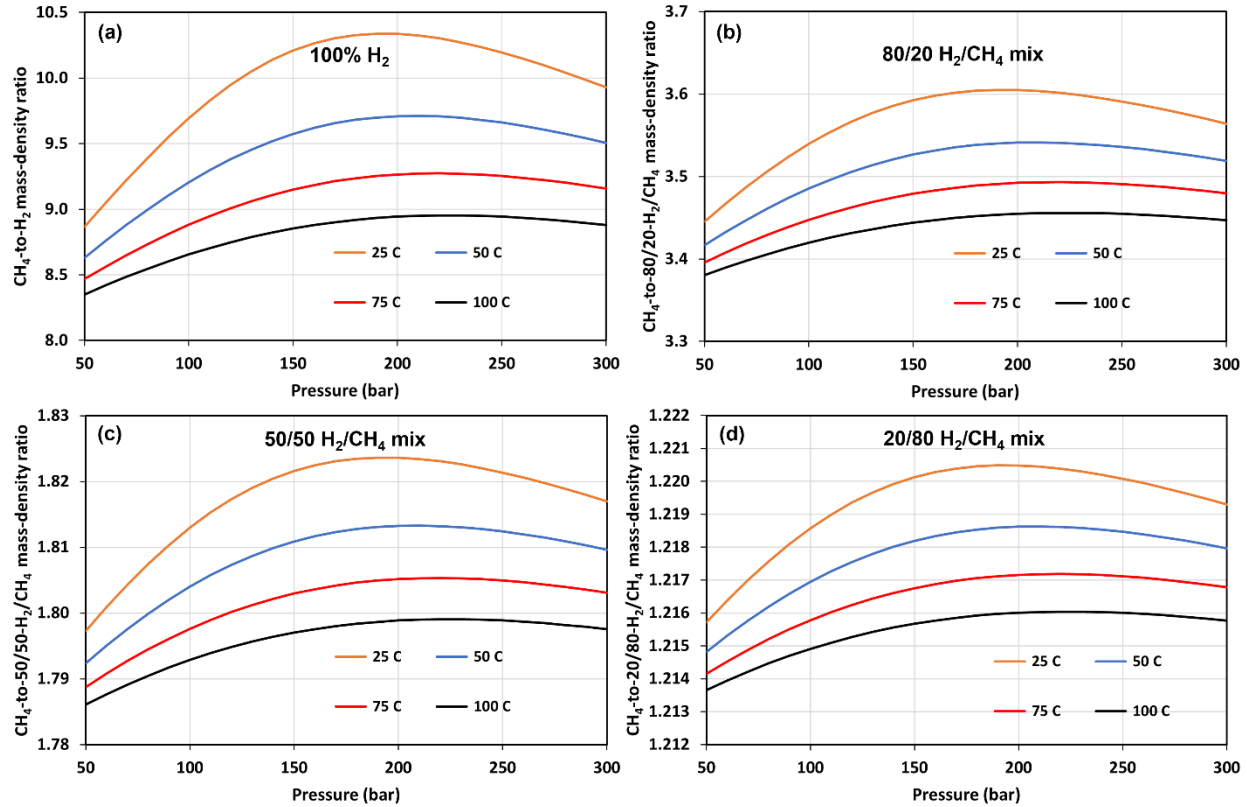


Figure 3.7. The mass-density ratios between CH₄ and various H₂/CH₄ mixtures by volume are plotted for 100% H₂ (a), 80/20 H₂/CH₄ mix (b), 50/50 H₂/CH₄ mix (c), and 20/80 H₂/H₄ mix (d) as a function of pressure and temperature.

Gravity override is very important for sweep efficiency and the magnitude of H₂ losses because it causes an elongated H₂/CH₄ gas plume to form near the top of the storage reservoir. This increases the contact area between the H₂/CH₄ plume and formation brine, where H₂ dissolution into the brine and diffusion within the brine result in H₂ losses. Gravity override also decreases sweep efficiency by reducing the fraction of the storage formation that can be used to store H₂. An engineering method that can be used to reduce the buoyancy driving force is to increase the fraction of CH₄ in the H₂/CH₄ gas mixture. Changing from pure H₂ to a 50/50 H₂/CH₄ mix reduces the buoyancy driving force by a factor of 4.7 to 5.7. However, the benefit from reducing the buoyancy driving force will be offset by the H₂ energy content of the working gas being only 19% to 22% (Table 3.2) versus 100% for pure H₂ storage. Changing from pure H₂ to a 20/80 H₂/CH₄ mix reduces the buoyancy driving force by a factor of 6.9 to 8.4. However, only 5% to 7% of the energy content of the working gas will be from H₂ (Table 3.2).

A key quantity for UHS is the threshold capillary pressure, which is defined as the pressure at which the H₂/CH₄ gas mixture can enter the largest available pore in the rock. Threshold capillary pressure is given in Equation (3.3)¹:

$$P_{c,th} = 2\sigma \cos \theta / r \quad (3.3)$$

¹ I. Chatzis, and N.R. Morrow, "Correlation of capillary number relationships for sandstone."

where $P_{c,th}$ is the threshold capillary pressure, σ is rock-fluid interfacial tension, θ is contact angle, and r is the radius of the largest pore. Because H_2 is found to have a lower σ than CH_4 , it results in less capillary trapping, making it easier for H_2 to enter the overlying caprock. It also makes it is easier for H_2 to be recovered from the storage reservoir than CH_4 .

As mentioned earlier, the injection rate of the H_2/CH_4 working gas plays an important role in determining sweep efficiency. A dimensionless group, called the capillary number, N_c , is used in the analysis of fluid flow to characterize the ratio of viscous force to surface or interfacial tension force^{1,2,3} as follows:

$$N_c = V\mu/IFT \quad (3.4)$$

where N_c is the capillary number, V is the Darcy velocity, μ is the dynamic viscosity of the displacing fluid (gas), and IFT is the gas-to-water interfacial tension.

The capillary number, N_c , depends on the ratio of dynamic viscosity, μ , and IFT. Based on measurements of gas-to-water IFT for H_2 and CH_4 by Chow and others (Figure 3.8a), the gas-to-water H_2 -to- CH_4 IFT ratio (Figure 3.8b) varies from 1.04 to 1.88 (Table 3.4). Combining the H_2 -to- CH_4 dynamic viscosity ratio Figure 3.5d) with the gas-to-water H_2 -to- CH_4 IFT ratio (Figure 3.8b), it is possible to determine the ratio of H_2 -to- CH_4 viscosity and gas-to-water IFT (Figure 3.8c), which is found to vary from 0.27 to 0.53 (Table 3.4).

Table 3.4. Range of measured gas-to-water interfacial tension (IFT) for H_2 and CH_4 . Also included are the calculated gas-to-water H_2 -to- CH_4 IFT ratio and H_2 -to- CH_4 viscosity to IFT ratio over indicated range of pressure and temperatures (Figure 3.8).⁴

	0 to 250 bar, 25 to 80 °C		
	IFT (milliN/m)	H_2 -to- CH_4 IFT ratio	H_2 -to- CH_4 viscosity/IFT ratio
H_2	49.4–71.3	1.04–1.88	0.27–0.53
CH_4	25.8–66.1		

The capillary number, N_c , is determined by the product of μ/IFT and the Darcy velocity, V . For a fixed energy injection rate (GJ/hr) and fixed number of gas-injection wells, the capillary number, N_c , is inversely proportional to the volumetric energy density (GJ/m³) of the injected gas. The volumetric energy density of the injected gas depends on reservoir pressure and the temperature of the injected gas, which is typically relatively cool (e.g., 25 °C). Although the injected gas is cool, the injected gas plume will eventually attain the reservoir temperature, which may be as high as 100 °C. The total volumetric energy density of the H_2/CH_4 mixture is plotted in Figure 3.9a. The H_2/CH_4 -to- CH_4 and CH_4 -to- H_2/CH_4 volumetric, energy-density ratios and the H_2 energy content of the injected gas are plotted in Figure 3.9b, c, d, respectively, as a function of volumetric H_2 percentage in the H_2/CH_4 mixture. Table 3.2, discussed earlier, summarizes the energy content in H_2/CH_4 gas mixtures.

¹ M.G. Rezk et al., “CO₂ storage potential during CO₂ enhanced oil recovery in sandstone reservoirs.”

² D. Zivar, and P. Pourafshary, “A new approach for predicting oil recovery factor during immiscible CO₂ flooding in sandstones using dimensionless numbers.”

³ Muhammed et al.

⁴ Chow et al., “Interfacial tensions of ($H_2O + H_2$) and ($H_2O + CO_2 + H_2$) systems at temperatures of (298–448) K and pressures up to 45 MPa.”

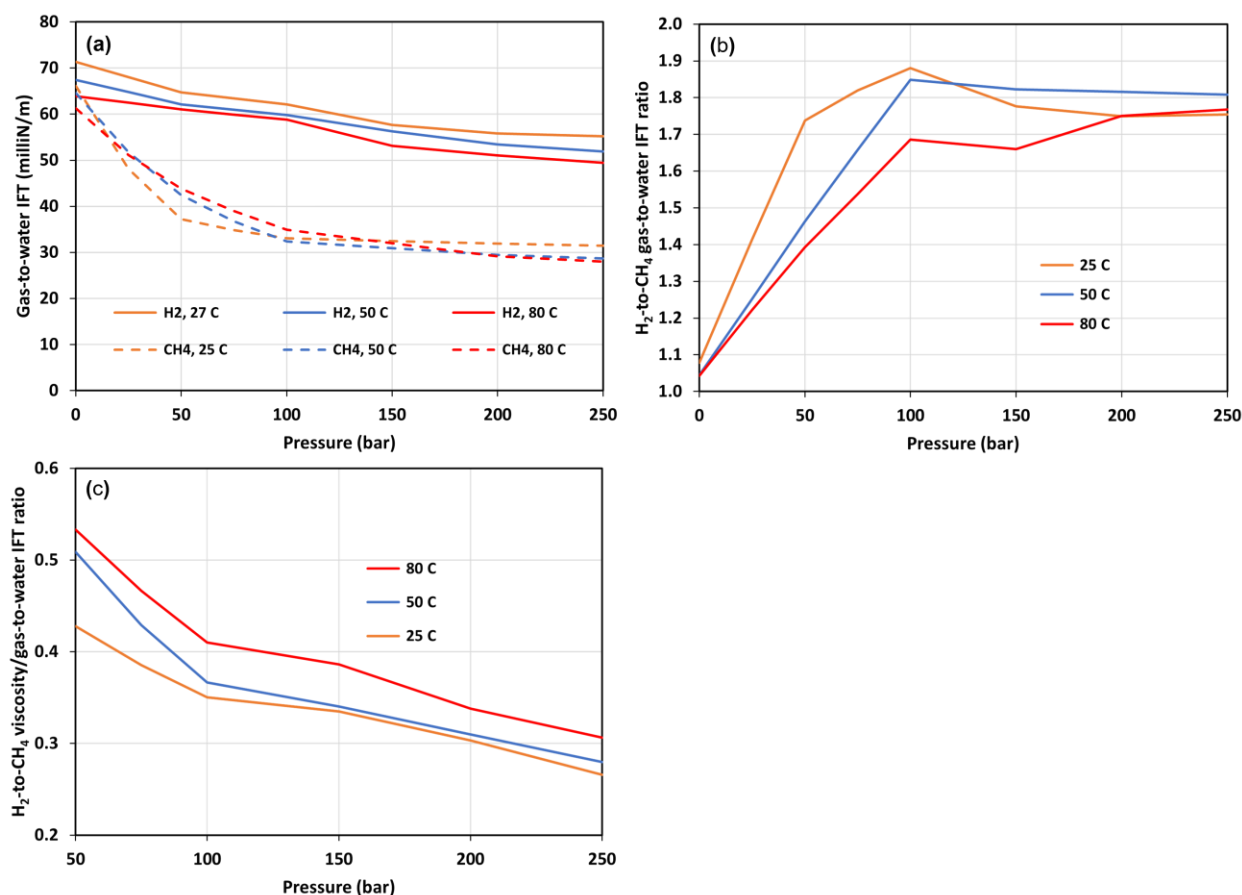


Figure 3.8. Gas-to-water interfacial tension (IFT) for H₂ and CH₄ (a), H₂-to-CH₄, gas-to-water IFT ratio (b), and H₂-to-CH₄, gas-to-water viscosity/IFT ratio (c) are plotted as a function of pressure from 0 to 250 bar and for temperatures of 25 (or 27) °C, 50 °C, and 80 °C.

Assuming an injection temperature of 25 °C, pure H₂ needs to be injected at a rate 3.69 to 4.31 times that of pure CH₄ to achieve the same energy injection rate. For an injection temperature of 25 °C, an 80/20 H₂/CH₄ gas mixture needs to be injected at a rate 2.40 to 2.59 times that of pure CH₄ to achieve the same energy injection rate, with 48% to 52% of the energy being from H₂. For an injection temperature of 25 °C, a 50/50 H₂/CH₄ gas mixture needs to be injected at a rate 1.57 to 1.62 times that of pure CH₄ to achieve the same energy injection rate, with 19% to 21% of the energy being from H₂. For an injection temperature of 25 °C, a 20/80 H₂/CH₄ gas mixture would need to be injected at a rate 1.17 to 1.18 times that of pure CH₄ to achieve the same energy injection rate, with 5% to 7% of the energy being from H₂.

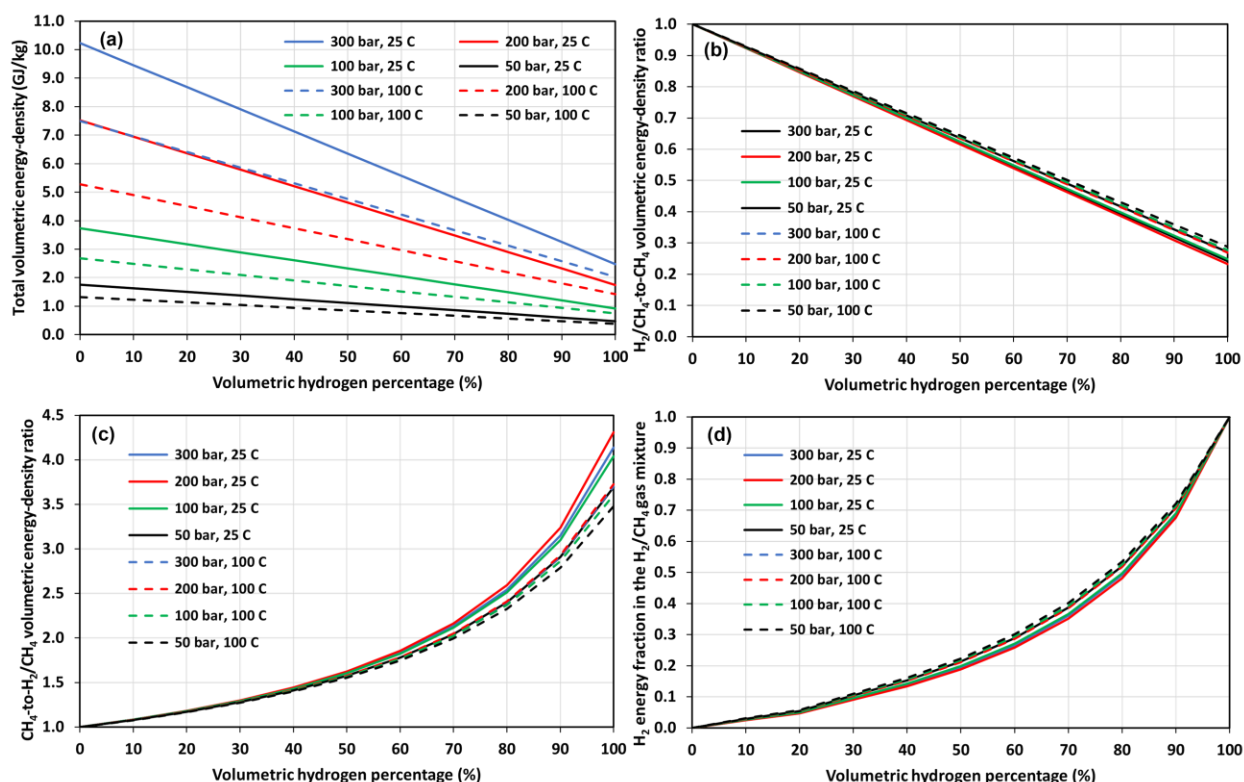


Figure 3.9. Total volumetric energy density (a), H_2/CH_4 -to- CH_4 volumetric, energy-density ratio (b), CH_4 -to- H_2/CH_4 volumetric, energy-density ratio (c), and H_2 energy fraction in the H_2/CH_4 gas mixture (d) are plotted as a function of volumetric H_2 percentage for pressures from 50 to 300 bar and temperatures of 25 and 100 °C. A temperature of 25 °C is typical for wellbore conditions, while 100 °C is representative of some reservoir conditions.

3.1.3 Relationship between UHS and UGS facility costs

Figure 3.8c can be used to scale costs in a UHS facility relative to corresponding costs in a UGS facility. Costs that scale to the volumetric flow rate of gas, such as the costs of wells and above-ground equipment (e.g., compressors), will scale to the CH_4 -to- H_2/CH_4 volumetric, energy-density ratio (Figure 3.8c). This would include both capital costs and operating costs, such as the power needed to operate the facility.

For a UHS facility that stores pure H_2 , costs tied to the volumetric flow rate of gas would increase by a factor of at least 3.69 to 4.31 compared to costs in a UGS facility, with 100% of the storage capacity being applicable to H_2 . If operating with pure H_2 requires more expensive alloys resistant to hydrogen embrittlement, the cost increase would be greater. For a UHS facility that stores an 80/20 H_2/CH_4 gas mixture, costs tied to the volumetric flow rate of gas would increase by at least a factor of 2.40 to 2.59 compared to those in a UGS facility, with 48% to 52% of the storage capacity being applicable to H_2 . For a UHS facility that stores a 50/50 H_2/CH_4 gas mixture, costs tied to the volumetric flow rate of gas would increase by at least a factor of 1.57 to 1.62 compared to those in a UGS facility, and 19% to 21% of the storage capacity would be applicable to H_2 . If more expensive alloys are required to operate with 50% H_2 , the cost increase would be greater. For a UHS facility that stores a 20/80 H_2/CH_4 gas mixture, costs tied to the volumetric flow rate of gas would increase by at least a factor of 1.17 to 1.18 compared to those in a UGS facility, with 5% to 7% of the energy storage capacity being applicable to H_2 .

3.1.4 Production rate/deliverability

The production rate and deliverability of a cyclic injection/withdrawal operation in a UHS reservoir are affected by several key phenomena and factors:

- Absolute permeability and porosity of the storage formation, which should be at least as high as in UGS reservoirs. Porosity in the range of 20% to 30% is preferred. Permeability in the range of 2 to 600 mD is reported as being sufficient for feasible UHS storage sites.¹
- Permeability anisotropy in the storage formation, which, in addition to affecting the trapping (stranding) of H₂/CH₄ working gas, will affect buoyancy-driven flow (gravity override) and upconing of cushion gas and formation brine during withdrawal.
- Changes in permeability and porosity caused by microbial, biogeochemical, and geochemical processes, described in Section 3.1.7.
- Viscosity and IFT of H₂/CH₄ gas and formation brine, discussed in Section 3.1.2, which affect sweep efficiency, stranding of H₂/CH₄ working gas, and the upconing of cushion gas and formation brine during withdrawal.
- Mass density of H₂/CH₄ working gas and formation brine, discussed in Section 3.1.2, which affects buoyancy-driven flow (gravity override) and upconing.
- Relative permeability and capillary-pressure hysteresis, described later in this section.
- Irreducible water and gas saturation, described later in this section.
- Spatial (areal and vertical) distribution of injection/withdrawal and injection and withdrawal rates, which, in addition to H₂/CH₄ working-gas stranding and sweep efficiency, will strongly influence the magnitude of upconing.

Absolute permeability and porosity of the storage formation can be readily determined from measurements on core samples. Permeability can also be determined from pressure analysis during fluid injection and withdrawal, which is valuable because it determines permeability at the field scale. Permeability determined from core samples complements permeability determined at the field scale by providing detailed spatial resolution of the permeability distribution, which can help inform decisions concerning the location of injection/withdrawal intervals along wells and the injection and withdrawal rates within those zones.

Relative permeability can be a function of saturation history, changing over time, as a result of multiple injection/withdrawal cycles, as demonstrated in CO₂-flow experiments.² During the storage process, the H₂/CH₄ working gas is the non-wetting phase injected into the storage formation filled with brine, which is the wetting phase. During injection of the H₂/CH₄ working gas, the non-wetting phase displaces the wetting phase (brine), which reduces the wetting-phase saturation by a process known as drainage. During the withdrawal of H₂/CH₄ working gas, some of the pore space that had been occupied with the non-wetting phase is displaced by the wetting phase, which increases the wetting-phase saturation by a process known as imbibition. The mobility of the H₂/CH₄ working gas is different during the drainage and imbibition processes due to the trapping of some of the H₂/CH₄ working gas in the storage formation, which shows up as hysteresis in the relative permeability curves. Trapping of the non-wetting phase is a result of capillary-pressure hysteresis, described below.

¹ Zivar et al.

² W.T. Pfeiffer, and S. Bauer, "Subsurface porous media hydrogen storage - scenario development and simulation."

Capillary-pressure hysteresis (Figure 3.10a) and relative-permeability hysteresis (Figure 3.10b) occur because it takes more pressure for the non-wetting phase to displace the wetting phase during the drainage process than it does for the wetting phase to displace the non-wetting phase during the imbibition process. Two important quantities affecting this hysteretic behavior are the irreducible water saturation, S_{rl} , and the residual gas saturation, S_{rg} . Residual gas saturation is particularly important because it controls the irrecoverable portion of the stored H_2/CH_4 working gas, which may affect the economics of UHS.¹ Relative-permeability hysteresis is quantified by the relative liquid permeability, k_{rl} , and the relative gas permeability, k_{rg} . Over most of the range of water saturation, k_{rl} and k_{rg} do not sum to 1, for reasons discussed below.

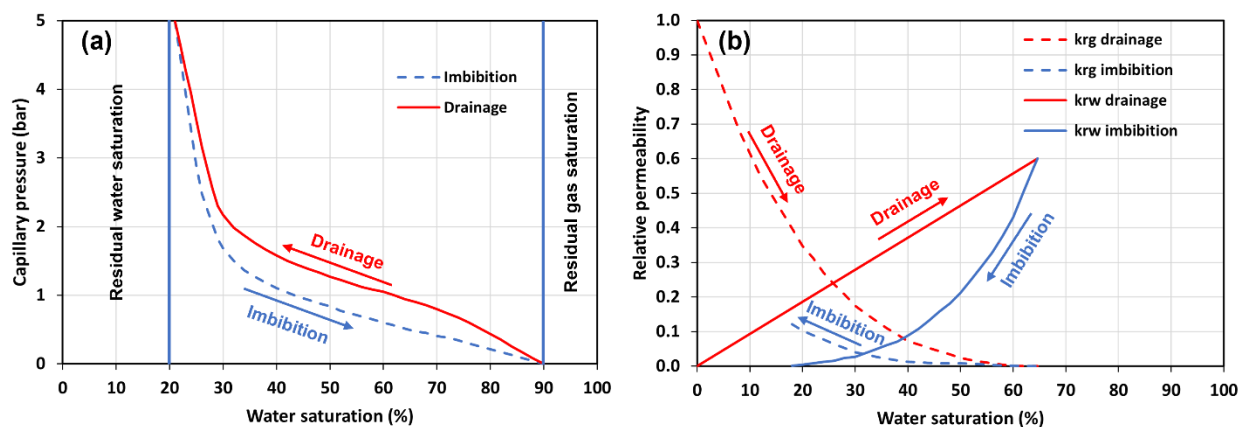


Figure 3.10. Hysteretic capillary-pressure curves (a) for gas-water systems, based on Figure 6 from Zivar and others.² Hysteretic relative-permeability curves (b) for water-gas systems, based on Figure 1a from Fatemi and Sohrabi.³

During withdrawal of H_2/CH_4 working gas, pressure is reduced and the pore space that had been occupied by the non-wetting phase is replaced by the wetting phase (brine). This process collapses some of the channels of the storage formation that had been filled with H_2/CH_4 working gas. This reduces the number of pathways between the stored H_2/CH_4 working gas and the withdrawal wells, which traps (strands) pockets of the working gas. The reduction of the relative permeability of the non-wetting phase increases the magnitude of pressure drawdown, which can lead to increased upconing of cushion gas and formation brine into the H_2/CH_4 working-gas zone. This may also lead to increased production of cushion gas and formation brine in the withdrawal wells, which may reduce the deliverability of the H_2/CH_4 working gas. Permeability anisotropy in the storage formation may suppress some of this upconing. The well-field design, including injection and withdrawal intervals and rates, can be important in taking advantage of the permeability structure in the storage formation to help mitigate the impact of H_2/CH_4 working-gas stranding and the upconing of nonproductive fluids.

A final note regarding stranded H_2/CH_4 working gas is that while the stranded gas may be considered an asset loss because it is no longer recoverable, it can be useful as part of the cushion-gas inventory. Because the stranded pockets of H_2/CH_4 will be in pressure communication with the H_2/CH_4 working-gas zone, the stranded gas would provide additional cushioning during injection/withdrawal cycles.

¹ Zivar et al.

² Zivar et al.

³ S.B. Fatemi, and M. Sohrabi, "Relative permeabilities for oil/water, gas/water, and gas/oil systems in mixed-wet rocks."

3.1.5 Injection rate/deliverability

Numerical studies have investigated optimal injectivity configurations to maximize H₂ recovery,^{1,2,3,4} for which they simulate the injection and production of pure H₂ into hypothetical anticlinal geological structures. These studies (Table 3.5) differ on injection and withdrawal periods, on the strategy used for initially filling the reservoir, and on the placement and number of injection and withdrawal wells. Despite these differences, all studies conclude that the H₂ production fraction increases for each successive withdrawal cycle, given that injection exceeds withdrawal for each successive cycle, resulting in the net quantity of stored H₂ steadily increasing. This trend should attenuate as more injection/withdrawal cycles are performed.

Table 3.5. Summary of injection/withdrawal conditions for various simulation studies.

Publication	Action	Rate (SCM/day/well)	Period (days)	Cycles
K. Lubon, and R. Tarkowski (2020) “Numerical simulation of hydrogen injection and withdrawal to and from a deep aquifer in NW Poland.”	H ₂ injection	334,760	30	1
	H ₂ injection	517,140	690	
	Production	3,042,003	180	4
	H ₂ injection	517,140	180	
W.T. Pfeiffer, and S. Bauer (2015) “Subsurface porous media hydrogen storage - scenario development and simulation.”	N ₂ injection	55,625	710	1
	H ₂ injection	155,000	210	
	Production	1,000,000	7	6
	Shut-in		1	
	H ₂ injection	150,000	50	
	Shut-in		30	
A. Sainz-Garcia et al (2017) “Assessment of feasible strategies for seasonal underground hydrogen storage in a saline aquifer.”	H ₂ injection	230,000	365	1
	H ₂ injection	335,000	243	3
	Production	Pressure controlled	122	
F. Feldmann et al (2016) “Numerical simulation of hydrodynamic and gas mixing processes in underground hydrogen storages.”	H ₂ injection	250,000	180	5
	Shut-in		180	
	H ₂ injection	4,320,000 (peak)	120	5
	Production	4,320,000 (peak)	240	

To guarantee a minimum reservoir pressure, the reservoir is first filled with a cushion gas. Cushion-gas injection represents a major cost of storage operations. One option to reduce this cost is to use cheaper gases such as CO₂, which has been analyzed as suitable for UGS.⁵ In depleted gas fields, residual NG could be used as cushion gas. In Sainz-Garcia et al (2017) and Feldmann et al (2016), H₂ is used as a

¹ Feldmann et al.

² W.T. Pfeiffer, and S. Bauer, “Subsurface porous media hydrogen storage - scenario development and simulation.”

³ Sainz-Garcia et al.

⁴ K. Lubon, and R. Tarkowski, “Numerical simulation of hydrogen injection and withdrawal to and from a deep aquifer in NW Poland.”

⁵ C.M. Oldenburg, “Carbon dioxide as cushion gas for natural gas storage.”

cushion gas, while Pfeiffer and Bauer (2015) considered inert N₂.^{1,2,3} While N₂ is cheaper than H₂ on a per-mass basis, it is more expensive than H₂ on a per-volume basis (Table 3.6). While H₂ costs more than NG on a per-mass basis, it has a similar cost to NG on a per-volume basis because of its low mass density. For all options, per-volume cushion-gas costs increase nearly linearly with depth. Because the volumetric energy density of H₂ and H₂/CH₄ mixtures also increases nearly linearly with depth, cushion-gas cost, relative to working-gas volume, is the same regardless of depth.

Cushion-gas compressibility is an important consideration. Less compressible gases (e.g., N₂ and CO₂) require a larger cushion-gas volume to result in the same cushioning effect. Tax credits for CO₂ storage make CO₂ an interesting cushion-gas option. The drawback of using alternative gases is that mixing might occur between the working and cushion gases during cyclic operations. Another drawback pointed out by Pfeiffer et al. is that the introduction of cushion gas may necessitate a reduction in injection rate for the first several injection/withdrawal cycles due to the increase in reservoir pore pressure.⁴ The influence of alternative cushion gases on reservoir performance is an area of active research.

Table 3.6. Summary of cushion-gas costs for various cushion-gas options, assuming (1) a typical cost for H₂ produced by steam methane reforming and water-gas shift, (2) a typical cost for N₂, and (3) NG priced at \$4.32 per million BTU.

	N ₂	H ₂	CH ₄	50/50 H ₂ /CH ₄	CO ₂
Cost per mass, \$/kg	1.04	2.10	0.20	1.15	-0.05
Cost per volume at 50 °C, 100 bar, \$/m ³	106.55	14.96	13.39	14.18	-5.36 ^(a)
Cost per volume at 75 °C, 200 bar, \$/m ³	186.17	26.46	23.85	25.25	-31.33 ^(a)
Density at 50 °C, 100 bar, kg/m ³	102.50	7.12	65.58	36.65	107.10
Density ratio at 50 °C, 100 bar, kg/m ³	1.56	0.11	1.00	0.55	1.63
Density at 75 °C, 200 bar, kg/m ³	179.10	12.60	115.75	64.68	626.53
Density ratio at 75 °C, 200 bar, kg/m ³	2.77	0.11	1.00	0.55	5.37
Compressibility	Second least	Most	Third most	Second most	Least
Surface separation needed?	Yes, if mixing occurs	No, if same composition as working gas	Yes, if mixing occurs	No, if same composition as working gas	Yes, if mixing occurs

(a) Assumes a CO₂ storage tax credit of \$50/metric ton.

The influence of various well-field layout options should be a priority in future investigations because it can influence H₂ recovery and be useful in mitigating potential operational issues. For example, mixing of cushion and working gases might be mitigated by allocating the H₂ injection well on one edge of the reservoir, allowing the cushion gas to be pushed to the other side.⁵ Pfeiffer and Bauer (2015) proposed to inject the cushion gas at the side of the geological structure to improve H₂ recovery for the initial set of injection/withdrawal cycles.⁶ Sainz-Garcia et al (2017) analyzed different well placements in order to minimize upconing and maximize H₂ recovery without the use of cushion gas.⁷ They concluded that placing several shallow withdrawal wells just beneath the caprock is essential to achieving higher H₂ recovery. However, this configuration also causes higher volumes of co-produced water.

¹ Feldmann et al.

² Pfeiffer et al., “Hydrogen storage in a heterogeneous sandstone formation: dimensioning and induced hydraulic effects.”

³ Sainz-Garcia et al.

⁴ Pfeiffer et al.

⁵ Feldmann et al.

⁶ Pfeiffer et al.

⁷ Sainz-Garcia et al.

Factors that may limit the ability to achieve target injection rates include (1) reservoir pressure declining to less than bottom-hole pressure limits, (2) minimum fracturing pressure, and (3) capillary-entry pressure. Upconing of the water-gas interface may be a significant factor that limits H₂ storage, especially when no cushion gas is used.¹ It is recommended that withdrawal operations be halted before upconing leads to large amounts of water production.

Another obstacle to achieving efficient H₂ recovery is related to the unstable displacement of the gas, such as viscous fingering and gravity override. As highlighted by Hagemann et al., viscous fingering leads to a greater lateral spread of gas and thus to higher amounts of unrecoverable gas in anticlinal reservoirs.^{2,3} The effects of unstable displacement can be controlled by the selection of the injection rate (see discussion on sweep efficiency in Section 3.1.2) and should be considered as part of the operational strategy.

Liebscher notes that porous reservoirs are typically used for seasonal gas storage, meaning that empty periods are longer than 80 days.⁴ Seasonal storage is an effective use of porous reservoirs (e.g., deep aquifers or depleted hydrocarbon fields) given that fluids move slower in porous media than in salt caverns, which leads to lower injection and withdraw rates. A maximum of two cycles of injection and production per year is suitable in porous reservoirs, while salt caverns could allow for multiple (up to 10) cycles per year.⁵

3.1.6 Gravity segregation of H₂/CH₄ mixtures

Gravity segregation of H₂ and CH₄ in H₂/CH₄ mixtures is possible due to the difference in their molecular weights.⁶ The possibility of gravity segregation of H₂ and CH₄ is important to determining the efficiency of UHS and how well placement can impact that efficiency. The most useful field experience in assessing the potential impact of H₂/CH₄ gravity segregation is subsurface town-gas storage, where mixtures of up to 50% H₂ have been stored.⁷ Experience with town-gas storage in Lobodice, Czech Republic, indicated that half of the stored H₂ was converted to CH₄ in just a few months.⁸ The H₂ conversion was caused by microbial activity, which is further discussed in Section 3.3. Such interaction makes it difficult to discern the influence of H₂/CH₄ gravity segregation on storage.

Based on research conducted at the molecular level, the impact of gravity segregation of H₂ and CH₄ in a UHS reservoir would appear to be insignificant.⁹ Charges on the H atoms in H₂ are negative while those in CH₄ are positive, making them attract. Consequently, the intermolecular distance between H₂ and CH₄ is shorter (3.4 Å) than that between CH₄ molecules. In addition, the binding energy of H₂-CH₄ (~14 meV) is larger than that between two H₂ molecules (~6 meV). The molecular-scale findings seem to indicate that gravity segregation would not significantly affect the storage of H₂/CH₄ mixtures. Diffusion, driven by concentration gradients, will also tend to re-equilibrate H₂ and CH₄, thereby suppressing gravity segregation. While the preliminary laboratory findings suggest that gravity segregation will not be significant, further study is needed to confirm those findings at the field scale.

¹ Sainz-Garcia et al.

² Hagemann et al., “Multicomponent gas rising through water with dissolution in stratified porous reservoirs - Application to underground storage of H₂ and CO₂.”

³ Hagemann et al., “Hydrogenization of underground storage of natural gas.”

⁴ A. Liebscher et al., “Geologic storage of hydrogen - Fundamentals, processing, and projects.”

⁵ Tarkowski, “Underground hydrogen storage: Characteristics and prospects.”

⁶ Pudlo et al.

⁷ J. Simon et al., “HyUnder - Hydrogen underground storage at large scale: Case study Spain.”

⁸ Simon et al.

⁹ Q.Q. Xue et al., “Co-mixing hydrogen and methane may double the energy storage capacity.”

3.1.7 Injectivity/productivity degradation (microbial, geochemical)

There are several biotic and abiotic processes that can affect H₂/CH₄ injectivity and productivity. First, sulfate-reducing bacteria (SRB) consume H₂ and reduce sulfate to corrosive hydrogen sulfide, H₂S, in subsurface hydrocarbon reservoirs. Sulfate reduction also generates a large quantity of water that will increase wetting-phase saturation. The resulting reduction of the non-wetting phase saturation will reduce the relative permeability of the non-wetting phase, which will decrease H₂/CH₄ injectivity. Secondly, iron-reducing bacteria (IRB) couple H₂ consumption with iron-hydroxide precipitation, which can impact H₂/CH₄ injectivity or loss of permeability in the storage reservoir.¹ Similarly, calcification is an abiotic, geochemical process that reacts H₂ to yield calcium precipitates that can plug pores.²

3.1.8 Engineering UHS deliverability

In summary, UHS deliverability depends on several factors: (1) H₂ energy content per volume of rock occupied by H₂/CH₄ working gas (see Section 3.1.1); (2) sweep efficiency, which is how much of the storage zone is occupied by H₂/CH₄ working gas (see Section 3.1.2); (3) well injectivity; and (4) productivity (see Section 3.1.5), which may be degraded by (5) microbial and geochemical mechanisms (see Section 3.1.7), and (6) asset loss (see Section 3.2). These factors will need to be considered in making the following key engineering decisions.

- H₂ and CH₄ volume fractions in the working gas, which affect the volumetric energy density of H₂/CH₄ working gas and the buoyancy driving force that controls gravity override, which in turn affects the fraction of the storage formation available to store the working gas and sweep efficiency.
- Storage depth (i.e., pressure), which affects the volumetric energy density of the H₂/CH₄ working-gas mixture.
- Injection rate, which affects viscous fingering (see Section 3.1.4), which in turn affects sweep efficiency (see Section 3.1.2). Note that for a given H₂/CH₄ working-gas storage requirement, injection rate is influenced by the number of injection wells.

The large mass-density contrast between H₂ and CH₄ and the fact that mass and volumetric energy densities of H₂ and CH₄ increase nearly linearly with pressure (Figure 3.1b) are two of the most important considerations in making key engineering decisions: namely, the volume fractions of H₂ and CH₄ in the working gas and storage depth. Doubling the storage depth nearly doubles the volumetric storage density for all H₂/CH₄ working-gas mixtures (Figure 3.11a). Formation permeability and trapping structure being approximately equal, a deeper storage formation should generally be the preferred option.

Choosing the volume fractions of H₂ and CH₄ involves tradeoffs. Increasing the volumetric fraction of H₂ increases H₂ energy content; however, it also increases the buoyancy driving force that governs gravity override (Figure 3.11b), which may reduce both sweep efficiency and the fraction of the storage formation available for storing the H₂/CH₄ working gas, while causing more stranding of working gas. Compared to 100% H₂, an 80/20 H₂/CH₄ mixture increases total energy density by a factor of 1.6 and reduces H₂ energy content by 20%, while reducing the buoyancy driving force by a factor of 3.5. Compared to 100% H₂, a 50/50 H₂/CH₄ mixture increases total energy density by a factor of 2.5 and reduces H₂ content by 50%, while reducing the buoyancy driving force by a factor of 5.2. Compared to 100% H₂, a 20/80 H₂/CH₄ mixture increases total energy density by a factor of 3.4 and reduces H₂ content by 80%, while reducing the buoyancy driving force by a factor of 7.8. These outcomes, together with material requirements for wells, pipelines, and auxiliary equipment and the intended use for a UHS

¹ NEA

² NEA

facility (e.g., H₂ storage versus dual H₂/NG storage), need to be considered in selecting the volume fractions of H₂ and CH₄ in the working gas.

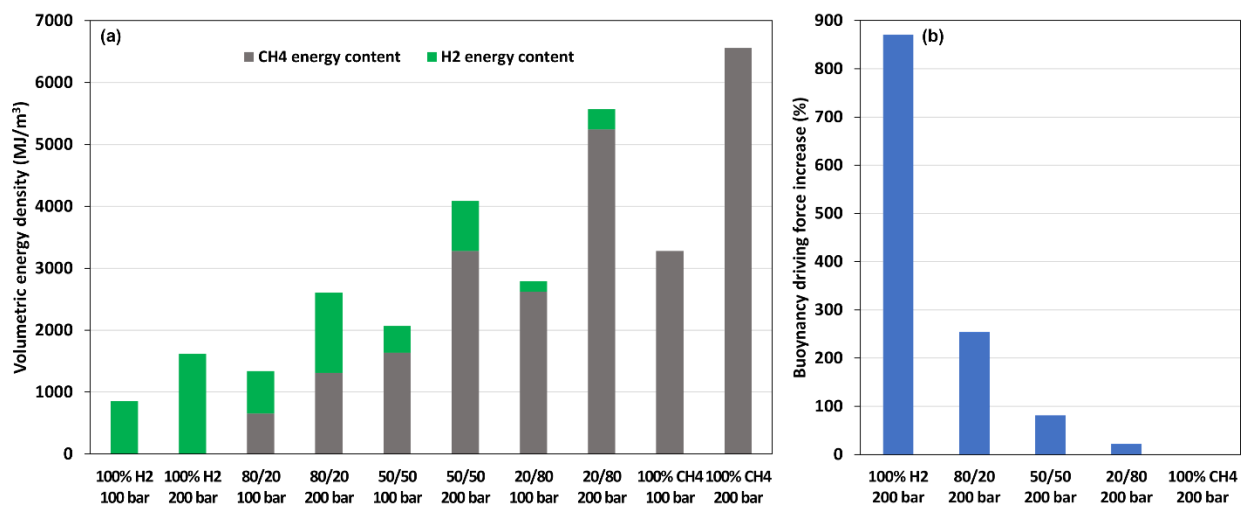


Figure 3.11. Volumetric energy density of H₂/CH₄ mixtures for pressures of 100 and 200 bar and a temperature of 50 °C (a) and buoyancy driving force increase compared to 100% CH₄ for 200 bar and 50 °C (b). The increase in buoyancy driving force is similar for 100 and 200 bar. Note that the H₂/CH₄ mixtures are on a per volume basis.

Because the previous discussion is focused on reservoir-engineering decisions, H₂/CH₄ mixtures are defined on a per volume basis. However, some engineering decisions that involve the selection of H₂/CH₄ mixtures, such as those affected by material considerations for pipelines and gas-handling infrastructure, as well as by end-user requirements, will likely be made on a mass-fraction basis. Figure 3.12 and Table 3.7 show the relationship between volumetric H₂ percentage and H₂ mass fraction in H₂/CH₄ mixtures. Because of the large contrast in mass density between H₂ and CH₄, a 50/50 H₂/CH₄ mix by volume only contains about 10% H₂ by mass, while a 90/10 H₂/CH₄ mix by volume contains about 50% H₂ by mass (Table 3.7).

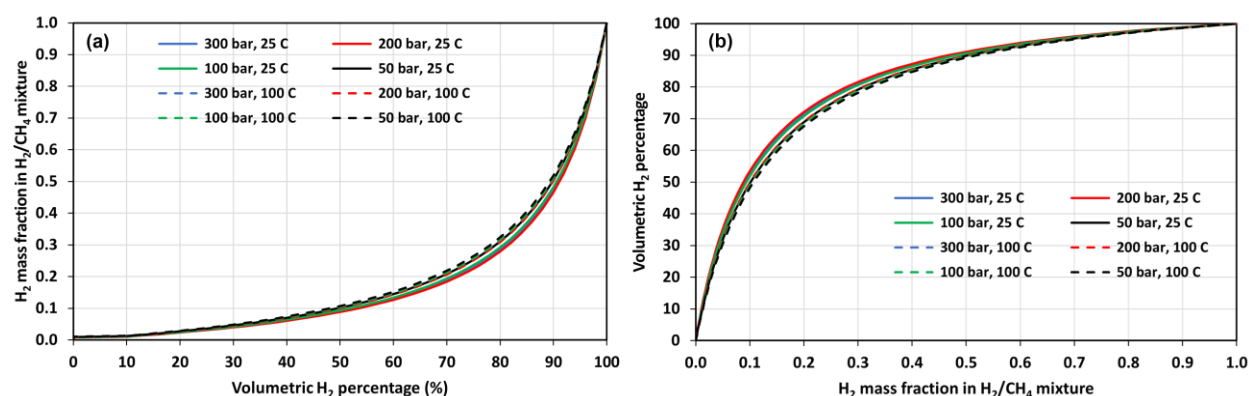


Figure 3.12. H₂ mass fraction in the H₂/CH₄ mixture is plotted as a function of volumetric H₂ percentage (a) and volumetric H₂ percentage is plotted as a function of H₂ mass fraction (b) in the H₂/CH₄ mixture for pressures from 50 to 300 bar and temperatures of 25 and 100 °C.

Table 3.7. The range in H₂ mass fraction is listed for various values of volumetric H₂ percentage for pressures from 50 to 300 bar and temperatures from 25 to 100 °C.

Volumetric H ₂ percentage	Range in H ₂ mass fraction in H ₂ /CH ₄ mixture	
	Low	High
0	0.0	0.0
10	0.0106	0.0131
20	0.0236	0.0291
30	0.0398	0.0488
40	0.0606	0.0739
50	0.0882	0.1071
60	0.1267	0.1523
70	0.1842	0.2184
80	0.2790	0.3239
90	0.4654	0.5188
100	1.0	1.0

3.2 Asset Loss

Key phenomenon affecting asset loss are (1) stranding of H₂/CH₄ working gas within the storage formation; (2) microbial conversion of H₂ to less-valuable forms of energy, such as CH₄ (see Section 3.3); (3) diffuse leakage through the caprock; (4) leakage through fault zones; and (5) leakage through wellbores with compromised integrity (see Section 4.0).

3.2.1 Stranding

The stranding of H₂/CH₄ working gas is caused by relative-permeability and capillary-pressure hysteresis, which is described in detail in Section 3.1.4. Stranding of H₂/CH₄ working gas may be a major cause of irrecoverable losses of H₂/CH₄ working gas, while reducing the deliverability of the working gas. The stranding of H₂/CH₄ working gas can also lead to an increase in the upconing of cushion gas and formation brine, which can also reduce the deliverability of H₂/CH₄ working gas. The quantity of stranded H₂/CH₄ working gas might increase with each successive cycle, leading to progressively lower relative permeability values.¹ One way to look at this phenomenon is that during each successive cycle the quantity of cushion gas left in place will increase. A possible benefit an increasing amount of cushion gas is that it may reduce the magnitude of pressure drawdown during withdrawal periods, which could reduce the tendency for H₂/CH₄ working-gas channels to collapse during the imbibition process.

3.2.2 Diffuse leakage through the caprock

Diffuse leakage through pores in the caprock is limited by two key effects. The first effect results from the low permeability of caprock formations, such shale or claystone. The second effect is capillary (or residual) trapping, where the non-wetting phase (H₂/CH₄ gas) is rendered immobile in the pore space, as disconnected ganglia, surrounded by the wetting phase (brine), are controlled by fluid properties and interfacial physics at the pore scale. Because the caprock is saturated with brine, the low-permeability sealing effect of the caprock is further assisted by the capillary-entry pressure, which must be exceeded in order for the non-wetting phase (H₂/CH₄ gas) to be able to displace the wetting phase (brine).

¹ Zivar et al.

Clay minerals (see more information in Section 3.4) in the caprock can react with H_2 . These reactions tend to cause swelling, which reduces permeability.¹ Clay mineralogy is complex and predicting its reactions with H_2 is difficult. Lassin et al. also found that most processes are buffered in clay because of the many species.² Furthermore, the H_2 Store project found that no changes occur to the permeability of the clay rock.³

3.2.3 Leakage through fault zones

Faults can act as a barrier or a conduit for gas flow.⁴ Increasing the capillary entry pressure causes a sealing effect. However, fault zone properties are often unknown and are subject to uncertainties.^{5,6} Under hydrostatic pressure conditions, buoyancy can play an important role for upward gas migration. Finally, barometric pumping may be strong enough to induce some vertical gas migration from shallow collector zones to the ground surface, especially when faults or fractures provide potential pathways.⁷

The driving force for buoyant flow of H_2/CH_4 gas, which is discussed in Section 3.1.2, depends on the H_2/CH_4 gas-to-water mass-density ratio, which is a function of the volumetric fraction of H_2 in the H_2/CH_4 mixture, temperature, and pressure (Figure 3.6). It is worth noting that the density of water only varies by 4% over the range of pressure and temperature in Figure 3.6. The buoyancy driving force is much greater for shallow depths and high temperatures. Therefore, deep formations in regions with a relatively shallow geothermal gradient are best with respect to minimizing the influence of buoyancy on UHS performance. Those conditions also maximize the energy-storage density.

Studies of CH_4 leakage from UGS reservoirs indicate that discrete pathways, such as faults, fault zones, and wellbores with a loss of well integrity are needed for significant leakage to occur. A detailed modeling study of NG leakage at the Leroy UGS facility in Wyoming found that fault leakage was the only plausible explanation of an observed NG leakage during the late 1970s.⁸ That 3-D modeling study found that NG leakage in the fault was at least 4–5 orders of magnitude greater than in the caprock. That study demonstrated the direct dependence of NG leakage on reservoir pressure and confirmed that leakage can be controlled by limiting the operating pressure. Starting in 1981, facility operators took measures to reduce reservoir pressures, resulting in a significant reduction in detected NG leakage.⁹ It is worth noting that this NG-leakage event was relatively minor and did not significantly disrupt operations at the Leroy UGS facility. Therefore, it is not representative of a major storage-failure event.

Hysteretic NG-leakage behavior, driven by geo-mechanical coupling, was observed at the Leroy UGS facility during injection/withdrawal cycles.¹⁰ During the injection season, overpressure was sufficient to open up fractures and to drive the upward flow of NG in the fault zone. When pressure dropped during the

¹ A. Lassin et al., “Hydrogen solubility in pore water of partially saturated argillites: Application to Callovo-Oxfordian clayrock in the context of a nuclear waste geological disposal.”

² Lassin et al.

³ Pudlo et al.

⁴ F. Gasandzade et al., “Sensitivity analysis of gas leakage through a fault zone during subsurface gas storage in porous formations.”

⁵ Q.J. Fisher, and R.J. Knipe, “The permeability of faults within siliciclastic petroleum reservoirs of the North Sea and Norwegian Continental Shelf.”

⁶ D.R. Faulkner et al., “On the internal structure and mechanics of large strike-slip fault zones: field observations of the Carboneras fault in southeastern Spain.”

⁷ C.R. Carrigan et al., “Trace gas emissions on geological faults as indicators of underground nuclear testing.”

⁸ M.J. Chen et al., “Analysis of fault leakage from Leroy underground natural gas storage facility, Wyoming, USA.”

⁹ Chen et al.

¹⁰ Chen et al.

withdrawal season, the fractures closed and the lost NG could not be pulled back to the storage formation due to a one-way “check-valve” effect, which caused the stranded NG to accumulate above the caprock horizon. Hysteretic curves of bottom-hole pressure versus gas inventory indicated leakage was triggered whenever the pressure exceeded 11.72 MPa, and that 5.5 BSCF of cushion gas was needed to support the minimum reservoir pressure of 9.65 MPa for appropriate gas withdrawal. Because working gas has averaged about 1 BSCF annually since the NG leak was controlled in 1981, 5.5 BSCF of cushion gas represents about 83% of the average gas-in-place, which is greater than typically required (50–70%) for UGS facilities in deep aquifers.¹

3.3 Subsurface Microbiology Fundamentals

Natural gas has been stored in North America for over a hundred years in salt caverns, saline aquifers, and depleted oil and gas fields. However, the introduction of a new component (H_2) to the UGS reservoir may introduce new and poorly understood hazards. One of the primary unknowns is the effect of H_2 on microbial communities that are naturally present in underground reservoirs at a broad range of conditions. Deep subsurface microbial communities can impact subterranean H_2 and NG storage^{2,3} through transformation of H_2 to a less valuable product, accelerated corrosion of well infrastructure, and pore space/fracture “clogging” resulting in near-well/reservoir fouling.

Although no large-scale H_2 injections are currently proceeding, some insight can be gained by the natural H_2 in these potential future storage reservoirs. H_2 naturally exists in low concentration in subsurface environments, and may be produced thermogenically, or during biological fermentation or CO/phosphite oxidation reactions.⁴ Once this hydrogen is produced, it is often quickly consumed by the natural microbial community within the reservoir. H_2 is known to be an energetic electron donor, supplying energy for a wide variety of subsurface microorganisms, many of which have been documented to exist naturally in the geologic units that are targets for H_2 gas storage. Even at low concentrations, hydrogen has been found to be a suitable electron donor when coupled with iron (III) reduction, sulfate reduction, sulfur reduction, and methanogenesis in subsurface reservoirs with a broad range of salinities and temperatures as high as 90 °C.⁵

In 2017, the Netherlands Enterprise Agency recognized this knowledge gap, and strongly recommended research and laboratory tests to investigate the effect of H_2 on the subsurface microbial community before initiating any large-scale H_2 injections.⁶ This lack of understanding was also a concern of the European Gas Research Group, which stated that of 20 potential reservoir phenomena that will negatively impact H_2 gas storage, the most serious potential issues are due the growth of bacteria.⁷ Recent studies have suggested that microbial utilization of H_2 may outstrip the rate of H_2 gas diffusion into the aqueous phase,⁸ setting up an enhanced gradient for continued H_2 mass transfer into the aqueous phase, where it may be more susceptible to loss mechanisms or difficult to produce. While previous literature demonstrates that microbial hydrogen consumption is expected, there is still a lack of comprehensive studies delineating microbial impacts on hydrogen storage.

¹ FERC

² A. Vigneron et al., “Succession in the petroleum reservoir microbiome through an oil field production lifecycle.”

³ S. Lahme et al., “Metabolites of an oil field sulfide-oxidizing, nitrate-reducing *Sulfurimonas* sp. cause severe corrosion.”

⁴ S.P. Gregory et al., “Subsurface microbial hydrogen cycling: Natural occurrence and implications for industry.”

⁵ Gregory et al.

⁶ NEA

⁷ R. Judd, and D. Pinchbeck, “Hydrogen admixture to the natural gas grid.”

⁸ C. Hemme, and W. van Berk, “Potential risk of H_2S generation and release in salt cavern gas storage.”

Potential microbial H_2 pathways are discussed below (see Figure 3.13).

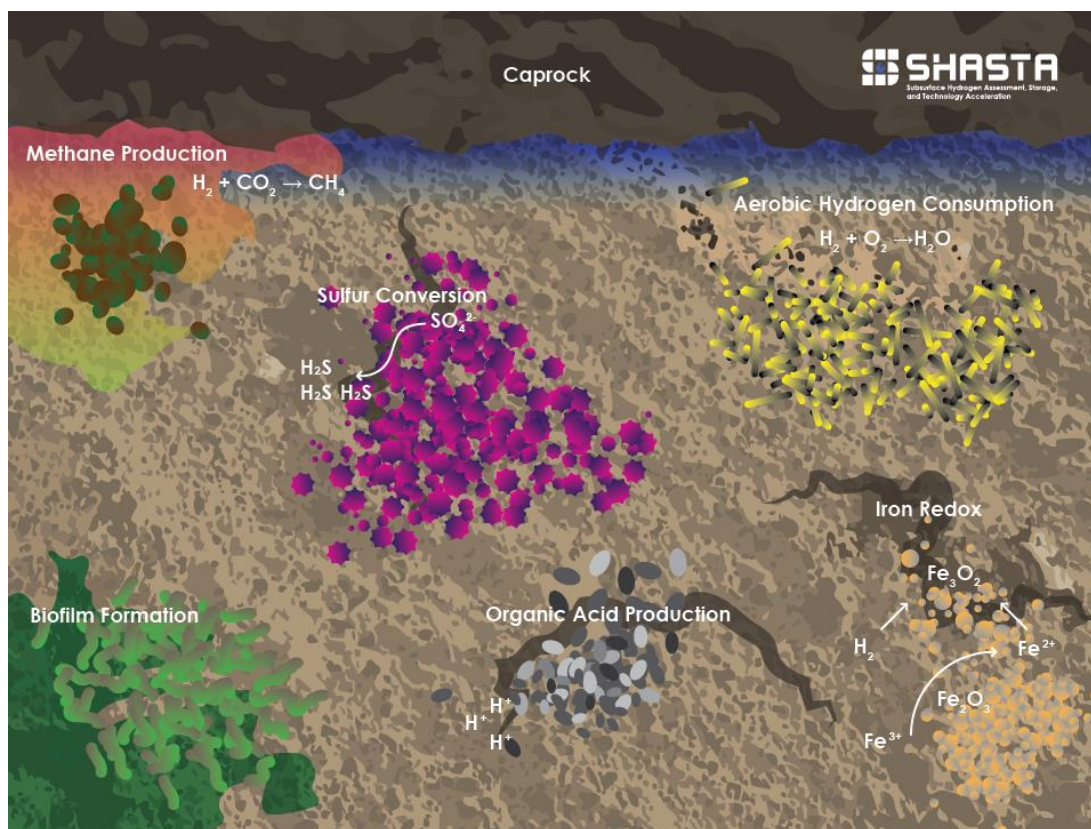


Figure 3.13. Cartoon showing how potential microbial activity can affect subsurface energy storage through hydrogenotrophic methanogenesis, hydrogen sulfide production, corrosion pathways and redox reactions, and secondary microbiological corrosion pathways.

3.3.1 Sabatier reaction (hydrogenotrophic methanogenesis)

One potential microbial mechanism of hydrogen consumption is the Sabatier reaction, in which microorganisms called methanogens oxidize hydrogen and reduce carbon dioxide to produce methane. The NG company Gaz de France previously injected a 50% blend of H_2/CH_4 gas in an underground storage reservoir. They found the microbially-induced Sabatier reaction to rapidly transform 50% of stored hydrogen gas into methane.¹ While methane may be used as a potential fuel, the energy loss from H_2 gas to CH_4 gas would be difficult to recover once microbially transformed.

3.3.2 Hydrogen sulfide production

A second, potentially more hazardous mechanism of H_2 consumption might occur through sulfate and sulfur reducers (SRBs). Gaz de France documented technical challenges associated with the reduced quality of stored gas due to these SRBs producing hydrogen sulfide gas (H_2S), which is a known hazard to operators, a contamination to the quality of gas, and a cause of many corrosion events in the oil and gas

¹ Tarkowski, "Underground hydrogen storage: Characteristics and prospects."

industry.¹ Town gas storage fields, which contain approximately 45% to 60% H₂, in the Czech Republic, have reported significant consumption of stored H₂ coupled to microbial CH₄ and H₂S production.²

Modeling studies have provided additional insights into the potential impact of microbial activity on H₂ storage in underground reservoirs. Several models demonstrate that reservoirs that are current targets of hydrogen storage, such as depleted oil reservoirs and salt caverns, have a high risk of H₂S production from SRBs.^{3,4} Modeling studies have highlighted the potential for microbial hydrogen consumption at the interface where injected hydrogen displaces existing gas in permeable sandstone reservoirs, leading to enhanced sulfide production and greater corrosive potential.⁵ Indeed, through culturing and DNA analysis, the microbial community in a deep subsurface storage gas aquifer was found to have an abundance of 69% sulfate reducers.⁶

3.3.3 Microbiological corrosion pathways/redox reactions

Hydrogen embrittlement of storage infrastructure can occur when H₂ concentration is high enough to permit diffusion into steel components. Abiotic corrosion in the absence of oxygen is theoretically and technically insignificant⁷; however, microbially-induced corrosion of steel can be extreme in the anoxic environment created by the introduction of H₂ to the subsurface.^{8,9} Hydrogen-consuming microorganisms have been implicated in causing corrosion, as well as various classes of heterotrophic microorganisms, at temperatures up to 90 °C and high salinities.^{10,11} Rates of microbially-induced steel corrosion in natural and engineered anoxic environments can range from 0.03 to 0.75 mm/yr. The impact of microbially-induced corrosion is underscored by the leak at the NG storage facility at the Aliso Canyon facility in 2015, which was ultimately attributed to microbially induced corrosion of a well casing.^{12,13}

3.3.4 Secondary effects

Not only is H₂ expected to affect the storage reservoir through CH₄ and H₂S production, but the shifting microbial community may lead to other unexpected byproducts, such as organic acids or even calcium carbonate scaling. The presence of microbial communities adapted to reducing, H₂-rich environments may contribute to corrosive mineral reactions through local pH changes and co-production of various acids.¹⁴ Some geologic components such as clay minerals, oxides, sulfates, carbonates, and other cement and pore-filling minerals may be susceptible to reaction and function as sinks for dissolved hydrogen. The impact of such reactions may range from negligible cation exchange with clays and buffering by

¹ W. Kleinitz, and E. Bohling, *Underground gas storage in porous media - operating experience with bacteria on gas quality*.

² P. Smigan et al., “Methanogenic bacteria as a key factor involved in changes of town gas stored in an underground reservoir.”

³ Amid et al.

⁴ Hemme and van Berk

⁵ Hagemann et al., “Hydrogenization of underground storage of natural gas.”

⁶ O. Basso et al. “Characterization by culture and molecular analysis of the microbial diversity of a deep subsurface gas storage aquifer.”

⁷ R. Cord-Ruwisch, “Microbially influenced corrosion of steel.”

⁸ D. Enning, and J. Garrelfs, “Corrosion of iron by sulfate-reducing bacteria: New views of an old problem.”

⁹ K.M. Usher et al., “Critical review: Microbially influenced corrosion of buried carbon steel pipes.”

¹⁰ NEA

¹¹ Gregory et al.

¹² SCAQMD, *Aliso Canyon Natural Gas Leak: Air Monitoring Results*.

¹³ Blade Energy Partners, *Root Cause Analysis of the Uncontrolled Hydrocarbon Release from Aliso Canyon SS-25*.

¹⁴ Usher et al.

carbonates to critical dissolution and mineral removal at key pore throat locations with unexpected changes to overall bulk permeability.^{1,2,3}

3.3.5 Future work/unknowns

Large-scale hydrogen storage will not be possible without the delineation of expected microbial activity in these systems. Before hydrogen can be safely and securely stored in underground reservoirs, the effect of gas injection on the naturally occurring microbial community and the associated change in chemistry needs to be assessed.

3.4 H₂ Interactions with the Storage Formation and Caprock

H₂ is unlikely to abiotically react with reservoir formations. Yekta et al. observed no major changes in mineralogy or texture in sandstone samples after 6 months of laboratory exposure to H₂ under reservoir conditions.⁴ However, thermodynamic and kinetic modeling suggested that reactions involving reduction of iron from Fe³⁺ (mainly in hematite) to Fe²⁺ may occur on a timescale of several years. H₂ dissolution into water (e.g., brines present at residual saturation or as thin films on mineral grains or pore throats) can also increase its availability for reaction, and the conditions and extent of this potential reaction pathway are difficult to predict. Major rock-forming minerals (i.e., aluminosilicates) are unlikely to be affected, but other geologic components such as clay minerals, oxides, sulfates, carbonates, and other cement and pore-filling minerals may be susceptible to reaction and function as sinks for dissolved H₂. This could change the mechanical strength of the rock matrix if hematite-containing cements or clay cutans at grain-grain contacts in sandstone reservoirs are reduced. The impact of such reactions may range from negligible cation exchange with clays and buffering by carbonates, to critical dissolution and mineral removal at key pore throat locations with unexpected changes to overall bulk permeability.^{5,6,7} The dissolution of minerals within the caprock seal could create new leakage pathways, but research indicates such reactions are unlikely to have a significant impact.⁸

Geochemical reactions between H₂, formation fluids, and rock mineralogy (see Figure 3.14) could lead to:

- Loss of H₂
- Contamination of stored H₂ by production of other gasses (e.g., H₂S)
- Mineral dissolution/precipitation, leading to increased or reduced injectivity
- Mineral dissolution, possibly leading to creation of migration pathways through the caprock
- Mineral dissolution affecting mechanical properties of the reservoir and caprock

¹ S. Henkel et al., “Mineral reactions in the geological underground induced by H₂ and CO₂ injections.”

² S. Flesch et al., “Hydrogen underground storage – Petrographic and petrophysical variations in reservoir sandstones from laboratory experiments under simulated reservoir conditions.”

³ Z. Shi et al., “Impacts of the subsurface storage of natural gas and hydrogen mixtures.”

⁴ Yekta et al.

⁵ Henkel et al.

⁶ Flesch et al.

⁷ Shi et al.

⁸ N. Kampman et al., “Observational evidence confirms modelling of the long-term integrity of CO₂-reservoir caprocks.”

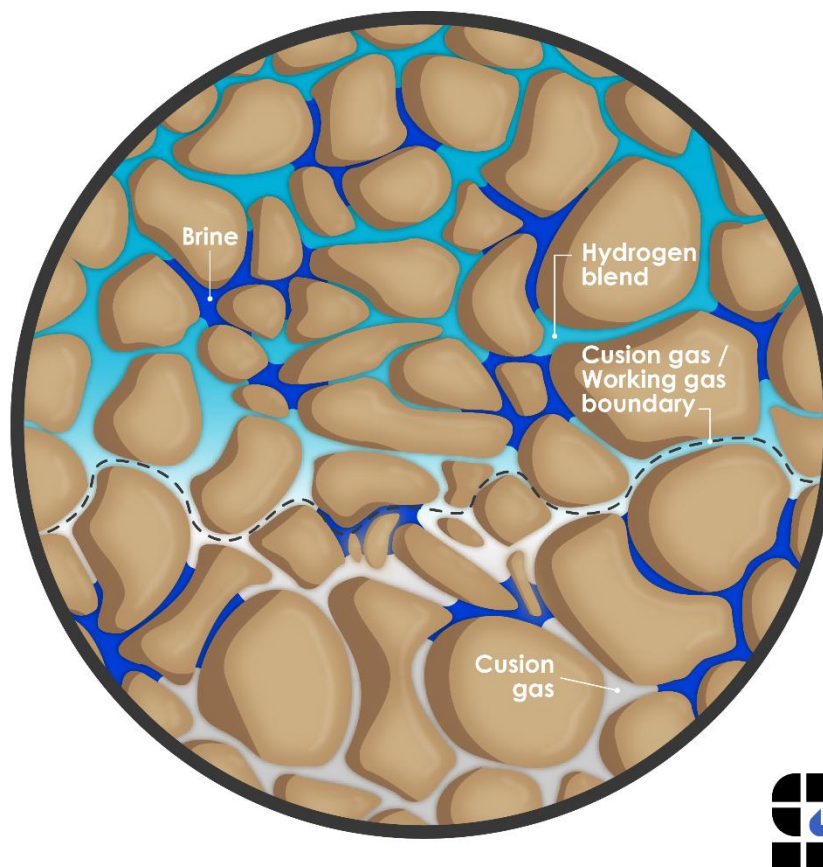


Figure 3.14. Schematic highlighting hydrogen and natural gas storage in the subsurface at the pore scale.

Any of these changes could compromise H₂ storage security and UHS efficiency.

Reactions of H₂ with dissolved sulfur species or sulfur-bearing minerals (e.g., pyrite) can occur, resulting in mineral dissolution, which can alter porosity, permeability, and mechanical properties. These reactions can also generate H₂S, decreasing the quality of stored H₂ gas. Generated H₂S can modify redox potential and the pH of waters, causing additional fluid-rock interactions. It can also compromise the well-field infrastructure due to its flammable, corrosive, and toxic nature.^{1,2,3} In general, there is no consensus on the significance of geochemical reactions under storage conditions relevant to UHS.

3.5 Downstream End-Use Factors Determining H₂/CH₄ Ratios for Economic Recovery

Blending ratios for H₂ and CH₄ for UHS are limited not only by technical limits of the storage reservoirs themselves (see Sections 3.1.1 and 3.1.2), but also by system constraints that limit the supply and demand for H₂ in the energy market. To date, the literature has highlighted technical constraints to market development in two key areas: (1) the transportation method for the blended or pure gas products withdrawn from wells and (2) the potential market size for end-use.

¹ Feldmann et al.

² Pfeiffer et al.

³ Sainz-Garcia et al.

A common concept in the literature for transporting blended NG and H₂ is the use of existing NG transmission and distribution pipeline networks. Blending demonstrations to date have typically been limited to about 20% or less of hydrogen by volume. These low limits are due to a lack of understanding of hydrogen effects on pipeline materials. While compatibility of pure hydrogen with pipeline materials has been well studied, less is known about compatibility of blends. Impacts of blends on pipeline materials is a focus of DOE's HyBlend project (<https://www.energy.gov/eere/fuelcells/hyblend-opportunities-hydrogen-blending-natural-gas-pipelines>). The economically favorable blending ratio for H₂ in storage might be further limited by the amount of H₂ gas that can be present in the pipeline system and not affect the end-users' gas-burning equipment.^{1,2} Researchers have worked toward articulating this type of constraint through both outreach to equipment vendors and system modeling. Prior work has indicated that many end-use appliances, such as boilers and cooking appliances, can handle up to 20% H₂ by volume and that NG pipeline compressors can handle up to about 10% without significant modification.^{3,4}

These percentages indicate that the current configuration and materials of the NG transmission system and end-use equipment might be the determining technical factor for blending rates in the system regardless of what concentrations are economical based on end-use demands.

Region-scale demand-based models have suggested that widespread conversion of power plants to hydrogen fuels might only lead to a required blending rate of H₂ concentration within the NG pipeline system of below 5% by volume.⁷ However, if heating is the driver of demand for H₂, as it was for a study of H₂ for heating in the UK,⁵ their models suggest that the capacity of H₂ relative to CH₄ in the pipeline system might be closer to 25% to 30%.

¹ Penget al.

² M. Pellegrini et al., "A preliminary assessment of the potential of low percentage green hydrogen blending in the Italian natural gas network."

³ I.A. Gondal, "Hydrogen integration in power-to-gas networks."

⁴ C. Tonia to, "Snam and Baker Hughes test world's first hydrogen blend turbine for gas networks."

⁵ Mouli-Castillo et al.

4.0 Well Integrity

As a primary pathway between the surface and the subsurface (underground storage complex), well integrity will be an important source of risk and liability. Wells must endure the stresses created by site operations and always maintain their structural integrity. Wells that lose control of injected or extracted fluids may become a human health or environmental hazard if the injectate is leaked into the atmosphere or groundwater in significant quantities. This is a concern for both injection wells and existing wells present at H₂ storage sites such as abandoned oil and gas wells. Maintaining the integrity of wells at UHS sites may be uniquely challenging because of the intrinsic properties of H₂ and the subsurface environment created by injection operations. In this section, the properties of H₂ and CH₄ relevant for understanding leakage risks are compared, well-integrity experiences from UGS operations are reviewed, and the potential concerns created by exposing various well materials to high concentrations of H₂ gas are considered.

4.1 Potential Impacts of Hydrogen Leakage

While well integrity is a major consideration for all subsurface energy operations, the properties of H₂ gas increase its potential for leakage through impaired wells. Table 4.1 compares properties of H₂ with CH₄ and other fluids such as CO₂, N₂, C₂H₆, and H₂O. H₂ has a lower molecular weight, density, and viscosity than CH₄, which increase its mobility in the subsurface. The solubility of H₂ in water is lower than that of CH₄ but its diffusivity is higher, which increases the risk of diffusion into well materials.¹ H₂ leaked through wells with compromised integrity has the potential to escape into shallow freshwater aquifers and/or the atmosphere.

In groundwater, H₂ is not considered a contaminant because it is not toxic to human health.² However, influx of H₂ into an aquifer may lead to the microbial production of H₂S or other compounds that degrade water quality.³ In the atmosphere, H₂ acts as an indirect greenhouse gas because it alters the tropospheric distribution of hydroxyl radicals, which impacts the concentration of CH₄ and ozone – two potent greenhouse gases. Research into the global warming potential of atmospheric H₂ is ongoing and current estimates are highly uncertain. Mitigating H₂ leakage from wells will be important to minimize these impacts. The difference in combustion properties of hydrogen relative to NG (e.g., wider flammability range and lower ignition energy) may require underground hydrogen storage facilities to be designed differently to comply with codes and standards and manage risk (Table 4.1).⁴ When safety is considered, H₂ leakage into a confined space is the primary concern. H₂ gas is lighter than air and has a relatively high diffusivity, which results in rapid dilution of the gas in open spaces.

¹ Tarkowski, “Underground hydrogen storage: Characteristics and prospects.”

² EERE, “Hydrogen Safety.”

³ NEA

⁴ R. Derwent et al., “Global environmental impacts of the hydrogen economy.”

Table 4.1. Comparison of the physical and chemical properties of hydrogen (H₂), methane (CH₄), carbon dioxide (CO₂), nitrogen (N₂), ethane (C₂H₆), and water (H₂O).

Properties	Unit	H ₂	CH ₄	CO ₂	N ₂	C ₂ H ₆	H ₂ O	Source
Kinetic diameter	nm	0.289	0.380	0.330	0.364	0.380	0.265	a
Molecular weight	g/mol	2.02	16.04	44.01	28.01	30.07	18.02	b
Critical temperature	°C	239.97	82.59	30.98	146.96	32.18	373.95	b
Critical pressure	MPa	1.30	67.59	108.42	49.90	71.60	324.25	b
Density at 20 °C and 0.1 MPa	kg/m ³	0.089	0.668	1.842	1.165	1.264	998.230	c
Viscosity at 45 °C and 12 MPa	cp	0.010	0.015	0.051	0.021	0.046	0.600	b
Solubility in water at 45 °C and 0.1 MPa	g/kg w	0.001	0.015	0.800	0.013	0.035	-	c
Diffusion in water at 25 °C	10 ⁻⁹ m ² /s	5.11	1.84	1.91	2.00	1.52	-	c, d
Diffusion in air at 20 °C	10 ⁻³ m ² /s	7.56	2.10	1.60	-	-	2.42	c
Enthalpy	J/g mol	0	-74,843	393,492	0	84,662	286,022	c
Entropy	J/g mol °K	130.60	186.19	213.66	191.56	229.48	70.00	c
Speed of sound at 0.1 MPa	m/s	1,320	450	280	354	316	1,480	c
Boiling point at 0.1 MPa	°C	-253.0	-161.5	-78.5	-196.0	-88.8	100.0	c
Heat capacity at constant pressure at 25 °C & 0.1 MPa	kJ/kg °K	14.306	2.232	0.851	1.041	1.757	-	e
Heat capacity at constant volume at 25 °C & 0.1 MPa	kJ/kg °K	10.180	1.709	0.657	0.743	1.472	-	e
Energy density	MJ/m ³	10.8-12.8	35.9-39.9	-	-	64.1-69.9	-	c
Specific energy	MJ/kg	120-142	50-56	-	-	48-52	-	c
Autoignition temperature	°C	500	580	-	-	515	-	c
Flammability limit in air at 20 °C	%	4-74	4-16	-	-	3-12	-	c
Flame temperature in air	°C	2,210	1,950	-	-	1,955	-	c
Ignition energy in air	MJ	0.011-0.012	0.28-0.30	-	-	0.24-0.26	-	f
Flammability limits in air	%	4-74	4.4-16.4	-	-	3-12.4	-	f
Explosion limits in air	%	18.3-59.0	5-17	-	-	Not available	-	f
Stoichiometric mixture (most easily ignited in air)	%	29	9.5	-	-	Not available	-	f

(a) N. Mehio et al., "Quantum Mechanical Basis for Kinetic Diameters of Small Gaseous Molecules."
 (b) NIST, "NIST Chemistry Webbook."
 (c) ToolBox, "The Engineering ToolBox."
 (d) P.A. Witherspoon, and D.N. Saraf, "Diffusion of methane, ethane, propane, and n-butane in water from 25 to 43 °."
 (e) Gas Encyclopedia, "Gas Encyclopedia Air Liquide."
 (f) V. Babrauskas, *Ignition Handbook*.

4.2 Well Integrity Incidents

The existing well systems at UGS sites make these reservoirs attractive early candidates for H₂/CH₄ storage. While uncommon, experience from UGS operations suggests that the most significant risk to the integrity of H₂/CH₄ storage facilities will be leakage through wells.^{1,2,3} Thus, the age and integrity of wells at UGS sites must be considered when evaluating a site for H₂/CH₄ storage. In 2017, it was estimated that active wells designed specifically for UGS had a median age of 48 years. Repurposed oil and gas wells operating at UGS facilities are older and have a median age of 74 years.⁴

Over the past 20 years, several notable well-leakage incidents have occurred at UGS facilities.⁵ The largest of these events was the LOC incident at Aliso Canyon, which began in October of 2015 and released about 1,300 metric tons of CH₄ each day for over 3 months.⁶ The cause of the leak was the rupture of the SS-25 well casing, which was corroded by microbial activity due to contact with groundwater.⁷ The SS-25 well was originally installed in 1953 for oil and gas production and repurposed for NG storage in 1973. The outdated design of the SS-25 well, which had only a single point of failure, and the lack of a downhole safety valve were noted as factors that significantly increased its risk of leakage.⁸ A recent review of well construction at UGS facilities identified 2,715 repurposed wells at 160 facilities that are currently in operation that have only a single point of failure.⁹ Currently, most available depleted fields were produced between 1929 and 1958.¹⁰ If H₂/CH₄ storage operations are conducted in depleted oil and gas reservoirs, older wells with outdated designs will pose a significant leakage risk. This will be particularly true if operators seek to repurpose legacy oil and gas wells for H₂/CH₄ injection/withdrawal operations as UGS operators have done in the past.

Legacy oil and gas wells near H₂/CH₄ storage facilities that do not penetrate the target reservoir can also pose a leakage risk. In January of 2001, NG escaped the salt caverns at the Yaggy UGS facility in Hutchinson, Kansas, and migrated laterally over 8 kilometers until it reached several abandoned brine-extraction wells. Damaged casing in one of the abandoned wells provided a conduit for the fugitive gas to migrate to the surface, where it resulted in two explosions that killed two people and destroyed several businesses.¹¹ The number of legacy wells located near active UGS sites has not been determined. Newly installed wells may also pose leakage risks at H₂/CH₄ storage facilities. For example, in August of 2004, a well-leakage incident at the Moss Bluff UGS facility in Liberty County, Texas, caused an explosion at the facility. The explosion was triggered when piping was breached at the wellhead of an injection well in de-brining mode. The breach was caused by a rapid change in flow rate that occurred when a separated production casing allowed pressurized gas to travel to the wellhead through brine piping, which forced the wellhead assembly to close. Inspection found that the breached pipe had already experienced corrosion

¹ B. Miyazaki, “Well integrity: An overlooked source of risk and liability for underground natural gas storage. Lessons learned from incidents in the USA.”

² E.J. Moniz et al., *Ensuring Safe and Reliable Underground Natural Gas Storage. Final Report of the Interagency Task Force on Natural Gas Storage Safety.*

³ D.R. Michanowicz et al., “A national assessment of underground natural gas storage: identifying wells with designs likely vulnerable to a single-point-of-failure.”

⁴ Michanowicz et al.

⁵ Moniz et al.

⁶ B.M. Freifeld, “Well integrity for natural gas storage in depleted reservoirs and aquifers.”

⁷ Blade Energy Partners

⁸ Moniz et al.

⁹ Michanowicz et al.

¹⁰ Long et al.

¹¹ Moniz et al.

after only 4 years of use.¹ The Moss Bluff incident released 6 billion cubic feet of NG, most of which was burned before escaping into the atmosphere. It should be noted that, in addition to CH₄, the Moss Bluff Facility contains one of the few H₂ storage caverns in the United States.²

The 2015 LOC incident at Aliso Canyon highlights these inherent risks and the need for effective risk reduction strategies to mitigate public concerns for any new UGS project.³ Following the incident, the U.S. Department of Energy (DOE) convened an interagency task force focused on UGS safety.⁴ This task force provided recommendations for ensuring well integrity at UGS facilities that will be relevant to operators of H₂/CH₄ storage facilities as well (see Section 7.0).

4.3 Durability of Well-Construction Materials under H₂-storage Conditions

During construction, a borehole is drilled and lined with steel casing, which is cemented in place. The primary components of a well include steel (carbon and/or stainless), plastic (typically PVC), and cement. As such, well integrity falls under three material groups (Figure 4.1):

1. Integrity of metallic components
2. Integrity of wellbore cement
3. Integrity of elastomers and seals

¹ Moniz et al.

² Tarkowski, “Underground hydrogen storage: Characteristics and prospects.”

³ Long et al.

⁴ Moniz et al.

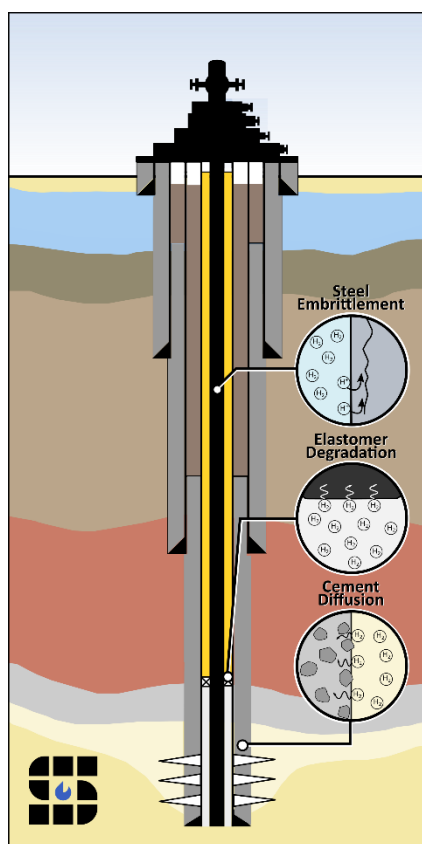


Figure 4.1. Cross sectional diagram of a H_2 storage injection well. The three major well components susceptible to integrity issues are shown: steel embrittlement, elastomer degradation, and cement diffusion.

4.3.1 Integrity of steel alloys

The compatibility of H_2 with steel and other metals has been extensively documented in the nuclear waste storage literature and for applications within the H_2 fuel economy.^{1,2} H_2 embrittlement – a complex phenomenon wherein H_2 moves into the atomic structure of steel, causing premature cracking and failure – is the primary reaction of concern and the cause of incompatibility and service degradation.³ The low-carbon steels often used in well systems are susceptible to multiple types of H_2 -mediated failure.⁴ Above ground, the main focus has been on materials used to transport mixtures of H_2 and CH_4 in pipelines.⁵ Variable composition steels and degassing treatments have been considered for mitigation of embrittlement reactions.⁶ Early assessments of leakage and chemical compatibility risks for subsurface storage of similar

¹ G.A. Cragolino, and N. Sridhar, “Localized corrosion of a candidate container material for high-level nuclear waste disposal.”

² C.W. San Marchi et al., *Fatigue Crack Initiation in Hydrogen-Precharged Austenitic Stainless Steel*.

³ O. Barrera et al., “Understanding and mitigating hydrogen embrittlement of steels: a review of experimental, modelling and design progress from atomistic to continuum.”

⁴ M.B. Djukic, “Hydrogen embrittlement of low carbon structural steel.”

⁵ M.W. Melaina et al., *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*.

⁶ Barrera et al.

gas blends concluded that degradation of metallic components by H₂ embrittlement and chloride attack was the primary failure mechanism of concern, and that H₂ loss as a result of abiotic interactions with geologic media was likely to be negligible.^{1,2} However, these assessments were based on thermodynamics of single reactions and did not consider multi-phase reactive systems, high-salinity brine, cement-mineral dissolution at critical pore throat locations, or deleterious products of microbial reaction.

H₂ embrittlement can occur when H₂ concentration is high enough to permit diffusion into metallic components. This process is distinguished from other corrosive reactions that take place in aqueous fluids. Abiotic corrosion in the absence of oxygen is theoretically and technically insignificant³; however, microbially-induced corrosion of steel can be extreme in the anoxic environment created by the introduction of H₂ to the subsurface.^{4,5} H₂-consuming microorganisms have been implicated in causing corrosion, as well as various classes of heterotrophic microorganisms, at temperatures up to 90 °C and high salinities.^{6,7} Rates of microbially-induced steel corrosion in natural and engineered anoxic environments can range from 0.03 to 0.75 mm/yr.

4.3.2 Integrity of wellbore cementation

The main challenge for the integrity of wellbore cementation is the prevention of gas leakage through the cement. For successful underground storage, it is important to prevent fluid or gas migration through the porous cement that is used to line a wellbore. It is believed that diffusivity, rather than reactivity, in cement will be the challenge to effectively storing H₂ underground. While reactivity may be a challenge for the steel casing and other metallic components in the wellbore, reactions between cement and H₂ may occur on redox-sensitive minerals such as ettringite (hexacalcium aluminate trisulfate hydrate) or hematite.⁸ These reactions would be driven by sulfate and ferric iron reductions by H₂. Models developed by Jacquemet et al. have shown that reactions would be kinetically limited and need to be catalyzed by the metabolism of microbes.⁹ However, models show that these reactions did not significantly impact the cement porosity. This is because these minerals are such a minor part of well cement.¹⁰ Class H and Class G well cements (the most commonly used well cements) have little to no sulfur components in their material makeup, making reactivity negligible for these well cements.

H₂ has the highest diffusion rate of all gases because it is the smallest molecule in the universe.^{11,12} Currently, there is little data available in the literature on H₂ diffusion through cement. The diffusion coefficient is the capacity of a material to transfer gases, dissolved gases, and/or ions under a concentration gradient as expressed by Fick's first law:

¹ Carden and Paterson

² Foh et al.

³ Cord-Ruwisch

⁴ Enning and Garrelfs

⁵ Usher et al.

⁶ NEA

⁷ Gregory et al.

⁸ N. Jacquemet et al. "Hydrogen reactivity with (1) a well cement – PHREEQC geochemical thermodynamics calculations."

⁹ Jacquemet et al.

¹⁰ Jacquemet et al.

¹¹ E. Jacobs et al., "The dependency of diffusion coefficients and geometric factor on the size of the diffusing molecule: Observations for different clay-based materials."

¹² Chababet al.

$$J = -D \frac{\partial C}{\partial x}$$

where J is the substance flux ($\text{kg}/\text{m}^2\text{-s}$), $\frac{\partial C}{\partial x}$ is the concentration gradient (kg/m^4), and D is the diffusion coefficient (m^2/s)

The coefficient of diffusion will differ depending on subsurface variables such as concentration, temperature, and pressure.¹ In porous materials such as cement, diffusion is impacted by the pore network (porosity ϕ , tortuosity τ , constrictivity δ) of the cement matrix.² Sercombe et al. split cement porosity into two types: (1) capillary pores (3–100 nm range), which depend on the water/cement ratio; and (2) microporosity (i.e., gel pores 1–3 nm), associated with hydration products such as C-S-H.³ However, there is also a third pore type due to air voids. Song et al. listed four types of cement pores: (1) gel pores (<10 nm), (2) small capillary pores (10–100 nm), (3) large capillary pores (100–1000 nm) and (4) air holes. Capillary porosity can be reduced by using a lower water/cement (w/c) ratio or various additives.^{4,5}

The pore network is controlled by parameters such as w/c ratio, cement type, admixtures, curing time (age), curing temperature, and pressure.⁶ Sercombe et al. measured the diffusion of H_2 in dried ordinary Portland cement (OPC) with different curing time and w/c ratios.^{7,8,9} The diffusion coefficient was found to decrease with curing time and to increase with w/c ratio. After 28-day curing, the diffusion coefficients were 4.8×10^{-7} and $1.9 \times 10^{-7} \text{ m}^2/\text{s}$ for w/c ratios of 0.65 and 0.5, respectively.¹⁰ Sercombe et al. showed that gas diffusion decreases with increasing relative humidity (RH).¹¹ For example, the diffusion coefficient for H_2 decreased by four orders of magnitude with an increase of RH from 3% to 93%. This is because high pore humidity will cause the narrow connections between large pores to be filled with liquid water,¹² reducing the percentage of pores available to gas migration. Phung et al. measured diffusion coefficients of dissolved gases in saturated cement-based material and observed that carbonation of cement resulted in a significant decrease in diffusivity (factor of 5).¹³ Using 10% limestone as a cement additive reduced cement diffusivity by 50%.¹⁴

Most UHS sites will be filled with brine.¹⁵ The solubility of H_2 in water under storage conditions depends on temperature, pressure, and salinity (Figure 3.11a). The solubility of H_2 in water increases with pressure, decreases with brine salinity, and increases slightly with temperature. Underground H_2/CH_4 storage

¹ Jacops et al.

² Q.T. Phung et al., “Insights and issues on the correlation between diffusion and microstructure of saturated cement pastes.”

³ J. Sercombe et al., “Experimental study of gas diffusion in cement paste.”

⁴ R. Tepfers, “Concrete technology – porosity is decisive.”

⁵ Y. Song et al., “Pore structure characterization of hardened cement paste by multiple methods.”

⁶ Phung et al.

⁷ M. Daimon et al., “Through pore size distribution of porous bodies in connection with kinetics of carbonation reaction of hardened cement.”

⁸ B.G. Kutchko et al., “Degradation of well cement by CO_2 under geologic sequestration conditions.”

⁹ Sercombe et al.

¹⁰ Daimon et al.

¹¹ Sercombe et al.

¹² Sercombe et al.

¹³ Phung et al.

¹⁴ Phung et al.

¹⁵ Chababet al.

conditions are likely to be in the range of 2500 to 3000 psi and 50 °C.¹ It is likely that, as with injected CO₂, there will be some solubility into the brine phase and there will be a “humid” head space.

4.3.3 Integrity of elastomers and seals

In the UGS industry, elastomers are used for packers and fittings that seal off the annulus between tubing and casing. There are H₂-resistant sealing elements already used in the H₂ industry. It remains to be investigated whether commonly used elastomers in UGS wells can resist the diffusion of H₂. Hydrogen permeation into these seal elements may increase their rate of degradation and result in failure over shorter time scales than typically observed in NG storage wells. A possible loss of seal integrity could result in a quick decompression. In this case, an inner blister fracture can lead to further failure because hydrogen quickly expands within the material.² This effect is dependent on the partial pressure and can also happen in the storage of other gases, but the difference with H₂ is its higher diffusivity. Sudden decompression usually does not happen in UGS facilities, and is only possible in the event of severe accidents. Understanding hydrogen effects on seal materials and improving durability is a key focus of DOE’s H-Mat consortium (<https://h-mat.org>).

The extreme mobility of H₂ raises concerns about operational safety, so technological improvement and materials development are needed for a potential transition to an H₂ economy. This may require a multi-materials approach for components associated with the H₂ distribution, storage, and dispensing infrastructure to achieve a cost-effective and safe working environment.

Polymeric materials play a vital role in high-pressure gas applications and down-hole well applications. Elastomers are loosely crosslinked polymers with the characteristics of rubber in terms of flexibility and elasticity, and are widely used in packers, completion equipment, liner hangers, plugs, annular-blowout preventers, wellhead equipment, stimulation and zonal isolation equipment, logging tools, sampling equipment, and motors for the oil and gas industry. Common elastomer materials for oil and gas industry applications include NBR (nitrile butadiene rubber), EPDM (ethylene propylene diene rubber), HNBR (hydrogenated nitrile butadiene rubber), FKM (fluoroelastomers), FEPM (perfluoroelastomers), and FFKM (perfluorocarbon elastomer). The chemical and mechanical properties of each of these elastomers depend on type of monomer, molecular weight, number, additive package, and type of crosslinks. Various copolymer technologies continue to bring new elastomers to the market. As a result, there are numerous brands and sub-materials from various manufacturers with branded names and trademarks, in addition to various additives incorporated for certain end-use requirements, making elastomers complex to work with.

Research has suggested that the most common failure mechanisms in elastomers operating in downhole environments include rapid gas decompression, temperature and chemical degradation, extrusion and nibbling, compression set, wear, and spiral failure.³ Simmons et al. summarized recent research efforts to better understand the compatibility of elastomer materials with H₂.^{4,5} Many of these efforts focus on compressed, gaseous H₂, as the oil and gas industry takes on challenges of introducing H₂ or H₂/CH₄ mixtures into its existing infrastructure.⁶ It is commonly agreed that significant chemical changes to the base polymer

¹ Chabab et al.

² J. Yamabe, and S. Nishimura, “Influence of fillers on hydrogen penetration properties and blister fracture of rubber composites for O-ring exposed to high-pressure hydrogen gas.”

³ H. Patelet et al., “Review of elastomer seal assemblies in oil & gas wells: Performance evaluation, failure mechanisms, and gaps in industry standards.”

⁴ K. Simmons et al., *Compatibility of Polymeric Materials Used in the Hydrogen Infrastructure*.

⁵ K.L. Simmons et al., “H-Mat hydrogen compatibility of polymers and elastomers.”

⁶ N.C. Menon et al., “Behaviour of polymers in high pressure environments as applicable to the hydrogen infrastructure.”

of most elastomers and dissolved H_2 cannot cause failure during rapid gas decompression.¹ Recent analysis has found certain filler materials and plasticizers can influence the magnitude of hydrogen effects on polymer materials. Studies found carbon black filler detains H_2 in the material and that silica filler mitigates blister damage.² Smaller filler size leads to a higher level of resistance to H_2 degradation. Also, the filler-gel structure that forms at the interface of filler and polymer was found to deteriorate, which was attributed to reduced elasticity of an NBR material after cyclic high-pressure H_2 exposure.³ Additionally, both density and inhomogeneity of elastomer crosslinks strongly affect the formation of micro-voids, which can cause severe damage.

Transport properties of H_2 gas in elastomers can vary depending on the operating temperature because polymers are more sensitive to temperature change than metals. However, elastomers are rarely used in temperatures above 250 to 300 °F, which limits understanding of high-temperature performance of elastomers. An H-Mat polymer study led by Pacific Northwest National Laboratory reported H_2 -induced phase separation of an oil-based plasticizer in sulfur-cured EPDM and NBR that might influence the rubber characteristics of both materials, especially at low temperatures.^{4,5} In addition, sulfur was found to concentrate around zinc oxide agglomerates, potentially making the material more susceptible to H_2 damage at the interfaces between zinc oxide and polymer. In parallel with experimental work, computational studies have advanced dramatically to offer increased capability of estimating performance of elastomer materials in high-pressure gaseous H_2 .⁶

¹ H. Fujiwara et al., “Degradation behavior of acrylonitrile butadiene rubber after cyclic high-pressure hydrogen exposure.”

² Yamabe and Nishimura

³ Fujiwara et al.

⁴ W.B. Kuang et al., “In situ friction and wear behavior of rubber materials incorporating various fillers and/or a plasticizer in high-pressure hydrogen.”

⁵ Simmons et al., “H-Mat hydrogen compatibility of polymers and elastomers.”

⁶ S.S. Kulkarni et al., “Damage evolution in polymer due to exposure to high-pressure hydrogen gas.”

5.0 Surveillance and Monitoring

5.1 Surveillance and Sensors for Operational Safety

As H_2 and CH_4 are both flammable gases, it is important to have surveillance and monitoring to evaluate and manage operational risks of UHS. Therefore, real-time monitoring is needed to assure storage infrastructure integrity and to detect early signs of gas leakage. National Fire Protection Association (NFPA) 2, *Hydrogen Technologies Code*, provides specific codes for the generation, installation, storage, piping, use, and handling of hydrogen in compressed gas or liquid form, and has mandated the use of hydrogen detection sensors in hydrogen operations. Similarly, the *International Fire Code* (IFC) has explicit requirements for hydrogen sensors and flammable detection in specific areas. The use of sensors will be mandated by enforceable code if either IFC 2009/2012 or NFPA 2 is adopted by a local jurisdiction.¹ The availability of sensor components certified to national standards to detect unintended hydrogen releases can facilitate the design and permitting of UHS facilities. Although hydrogen operation and the codes for hydrogen safety are established in industry, standards and codes still need to be specifically defined and added for UHS scenarios.

Real-time monitoring is needed to inform timely decision-making for safe, smart, and efficient UHS operations. This information is also needed to construct data-constrained reservoir models used to guide well-field operations. Although there are many types of commercial H_2 sensors, as described in Table 5.1, existing sensor technologies are not completely compatible with the needs of large-scale UHS facilities, especially geospatial features, such as wide-area and long-distance sensing capabilities.² Moreover, subsurface conditions are more challenging due to higher pressures and temperatures than are encountered in typical sensor-operating conditions. These harsher conditions will demand increased durability and stability of the sensing components. H_2 has a wider flammability range (4% to 75% by volume) than CH_4 (5% to 15% by volume) in air (see Table 4.1). For safe operation, sensor devices need to be inert and passive, and compatible with flammable conditions.

The subsurface system is an actively evolving environment, even more so with stored H_2/CH_4 mixtures. Microbial activities in subsurface environments may lead to H_2 loss and the deterioration of the storage reservoir and infrastructure. Periodic sampling cannot provide real-time monitoring of gas composition, H_2 transformation, or H_2/CH_4 migration and possible segregation within the constantly evolving storage system. Sensor technology is also critical to detecting and diagnosing problems with wellbore integrity due to H_2 embrittlement in steel casing, diffusion in cement, and interactions with elastomers. Early detection of corrosion, cracking, and chemical parameters is needed for well-informed maintenance before catastrophic failures.

¹ K. O'Malley et al., *An Overview of North American Hydrogen Sensor Standards*.

² T. Hübert et al., *Sensors for Safety and Process Control in Hydrogen Technologies*.

Table 5.1. Existing representative H₂ sensors compared to emerging sensor technologies.¹

Sensor	Temporal	Spatial	Advantages	Disadvantages	TRL
Catalytic Pellistors	Real-time	Point sensor	Most common (33%), commercial, mature, robust	Not H ₂ selective. Require O ₂ to operate correctly. Heated coil.	9
Electrochemical Sensors	Real-time	Point sensor	29% market. Linear, ppm sensitivity, <30s response time	Require electrolytes. Cross-sensitivity to CO. Aging.	9
Thermal conductivity sensors	Real-time	Point sensor	16% market. No need of O ₂ . Stability, fast response	Nonspecific. Cross-sensitivity.	9
Resistive sensors	Real-time	Point sensor	13% market. Small size, 10s response time.	Humidity and T effect. Cross-sensitivity	9
Work function sensors	Real-time	Point sensor	2% market. Small size. High selectivity.	Drift. Hysteresis.	6-9
Optical schlieren imaging. Shadowgraph	Real-time	Standoff sensor	Stand-off, wide area monitoring	Limited in beam direction, not H ₂ specific. Interferences.	6-8
Raman Lidar	Real-time	Standoff sensor	Remote, wide area monitoring, 10-50 m distance	High-intensity laser safety. Limited to field of view.	6-8
Acoustic leak detection	Real-time	Standoff sensor	Wide area monitoring, >10 m range, millisecond response	Not specific to H ₂ . Not quantitative	9
Optrode	Real-time	Point Sensor	No source of ignition in explosive atmosphere.	Drift due to aging and poisoning by SO ₂ , H ₂ S	6-8
Distributed Optical Fiber Sensors	Real-time	Distributed sensor	Distributed sensing, long distance, multi-parameter, Non-electrical, high sensitivity, fast response.	Cost of interrogation instrument.	5-8
Passive wireless SAW sensors	Real-time	Point sensors	Passive, Wireless capability, Low cost, High sensitivity.	Interference from humidity and T	5-6

As emerging sensor technologies, optical fiber sensors have advantages of small size, flexibility, long-distance sensing capability, multi-parameter capability, chemical stability under harsh conditions, and spatially distributed monitoring with location information.² Passive wireless surface acoustic wave (SAW) sensors have advantages of small size, low cost, ease of fabrication, and compatibility with wireless telemetry.³ These sensors can also be designed for specific parameters, including physical parameters (e.g., pressure, temperature, vibration) and chemical parameters (e.g., H₂, CH₄, pH, corrosion).^{4,5,6} More importantly, compared to electrical-based sensors, the optical fiber-based and SAW sensors' inertness and elimination of electrical wire ensure safe operation in flammable H₂/CH₄ gas mixtures.

¹ Hübert et al.

² P. Lu et al., "Distributed optical fiber sensing: Review and perspective."

³ J. Devkota, P. Ohodnicki, and D. Greve, "SAW sensors for chemical vapors and gases."

⁴ Y. Zhang et al., "Recent advancements in optical fiber hydrogen sensors."

⁵ R. Wright et al., "Corrosion sensors for structural health monitoring of oil and natural gas infrastructure: A review."

⁶ F. Lu et al., "Distributed fiber optic pH sensors using sol-gel silica based sensitive materials."

The sensor technologies can be combined with advanced data analytics methods [e.g., artificial intelligence (AI), machine learning] to support a safe and smart H₂/CH₄ storage system through identification of predictive signatures and informed maintenance operations before catastrophic failures occur. Real-time and ubiquitous sensor networks will provide high-quality and accurate data feed for the AI algorithms to enable an intelligent monitoring system for UHS.

5.2 Monitoring for Groundwater Protection

The driving forces and conditions that could result in gas and brine leakage to overlying aquifers and potentially lead to groundwater contamination are similar for UHS and geological CO₂ storage (GCS). Both GCS and UHS involve the injection of a pressurized, buoyant fluid capable of driving leakage through conduits to overlying aquifers. Methods for monitoring leak detection in aquifers above a GCS reservoir have undergone extensive research and development efforts.¹ These efforts and the resulting technologies are relevant to UHS.

The U.S. Environmental Protection Agency (EPA) established the Class VI rule for GCS that sets the minimum technical criteria to protect underground sources of drinking water (USDWs) from the long-term subsurface storage of CO₂.^{2,3} The Class VI rule requires periodic monitoring of groundwater quality to identify geochemical changes due to leaching or mobilization of heavy metals and organic compounds that can result from the presence of CO₂ migration or brine fluid displacement above the primary confining zone, which can potentially migrate into a USDW, causing degradation of drinking water quality.⁴

Leakage of CO₂ and brine from a GCS reservoir into overlying aquifers through faults and compromised wells may change the quality of USDW by decreasing pH and increasing total dissolved solids (TDS) concentrations and gas-phase CO₂ saturations.^{5,6,7,8,9,10} Similarly, leakage of H₂/CH₄ gas and brine may change the quality of USDW. As with brine and CO₂ leakage from a GCS reservoir,¹¹ subsurface changes in pressure, TDS concentration, and gas-phase H₂ and CH₄ saturations caused by brine and H₂/CH₄ gas leakage may be detected by combining surface-based geophysical methods, which indirectly measure those changes, with downhole monitoring methods, which directly measure pressure and chemical changes in the overlying aquifers.

¹ X.J. Yang et al., “Assessment of geophysical monitoring methods for detection of brine and CO₂ leakage in drinking water aquifers.”

² EPA, “Safe Drinking Water Act.”

³ EPA, “Class VI - Wells used for Geologic Sequestration of CO₂.”

⁴ Yang et al., “Assessment of geophysical monitoring methods for detection of brine and CO₂ leakage in drinking water aquifers.”

⁵ S. Carroll et al., “Geochemical detection of carbon dioxide in dilute aquifers.”

⁶ A. Lawter et al., “Evaluating impacts of CO₂ intrusion into an unconsolidated aquifer: I. Experimental data.”

⁷ T. Xiao et al., “Potential chemical impacts of CO₂ leakage on underground source of drinking water assessed by quantitative risk analysis.”

⁸ Z. Wang et al., “Modeling of time-lapse seismic monitoring using CO₂ leakage simulations for a model CO₂ storage site with realistic geology: Application in assessment of early leak-detection capabilities.”

⁹ T.A. Buscheck et al., “Downhole pressure and chemical monitoring for CO₂ and brine leak detection in aquifers above a CO₂ storage reservoir.”

¹⁰ C.B. Yang et al. “Geochemical sensitivity to CO₂ leakage: detection in potable aquifers at carbon sequestration sites.

¹¹ Buscheck et al.

5.3 Surface-Based Geophysical Monitoring Methods

Surface-based geophysical monitoring methods complement downhole monitoring methods because they sample an area larger than individual monitoring wells.¹ Geophysical methods use many surface-based sensors to monitor a large area and to construct 3D subsurface images of a large volume. Downhole monitoring typically involves a limited number of monitoring wells and a limited number of sensors per well. It is important to combine downhole measurements with geophysical methods that are sensitive to H₂/CH₄ gas and TDS to improve leak detection and add confidence that “no detection” means no leak.

Yang et al. investigated the effectiveness of the primary commercially available surface-base geophysical methods: (1) magnetotellurics (MT), (2) electrical resistivity tomography (ERT), (3) gravity, and (4) seismic reflection, as well as downhole monitoring of (5) pressure and (6) TDS. They found the probability of detecting a leak increases as more CO₂ and brine leak into the overlying aquifers. They also found that when only one monitoring method is used, leakage scenarios that change groundwater composition may go undetected and larger leaks are required in order to be detectable, compared to when multiple methods are used.²

5.3.1 Magnetotellurics and electrical resistivity tomography

The MT and ERT methods are grouped because both detect changes in the bulk electrical resistivity caused by the leakage of H₂/CH₄ gas and brine. Leakage results in distinctly different effects with regards to resistivity. Because H₂/CH₄ gas has greater electrical resistivity than brine or groundwater, resistivity increases with H₂/CH₄ gas content. Because the solubilities of H₂ and CH₄ in water are much less than that of CO₂, the dissolution of H₂/CH₄ gas in brine or groundwater will have a negligible influence on TDS, which will have a negligible influence on resistivity.

Electrical resistivity of the rock is a complex function of porosity, pore-fluid saturation and TDS, temperature, and clay content. Resistivity values of common rock types vary by several orders of magnitude. Leakage of brine and H₂/CH₄ into groundwater changes pore-species concentrations [Na⁺, Cl⁻, HCO₃⁻, H⁺, Ca²⁺, H₂ (gas), CH₄ (gas), H₂ (aqueous), and CH₄ (aqueous)]. The pore-fluid electrical conductivity (EC) can be estimated directly from these ion concentrations³ or from TDS concentration. A simple linear equation can be used to convert TDS to EC, which can then be modified to account for its dependence on temperature.^{4,5} A modified Archie’s equation can be used to account for the additional clay-conduction pathway, and bulk-rock EC can then be determined based on its dependence of all of these influences.⁶

¹ Yang et al., “Assessment of geophysical monitoring methods for detection of brine and CO₂ leakage in drinking water aquifers.”

² Yang et al., “Assessment of geophysical monitoring methods for detection of brine and CO₂ leakage in drinking water aquifers.”

³ F. Visconti et al., “An empirical equation to calculate soil solution electrical conductivity at 25 degrees C from major ion concentrations.”

⁴ N.R.G. Walton, “Electrical-conductivity and total dissolved solids - What is their precise relationship?”

⁵ M. Hayashi, “Temperature-electrical conductivity relation of water for environmental monitoring and geophysical data inversion.”

⁶ Yang et al., “Assessment of geophysical monitoring methods for detection of brine and CO₂ leakage in drinking water aquifers.”

5.3.2 Gravity and seismic reflection

Gravity and seismic reflection are grouped because they are non-invasive, passive, geophysical-imaging methods that are sensitive to changes to the bulk-rock, mass-density distribution over time, which are controlled by changes to the distribution and mass densities of the gas and liquid phases in the rock. Over the last few decades, the gravity method has been successfully deployed to monitor dynamic, multi-phase flow behavior for geothermal reservoirs, hydrocarbon production,^{1,2} active volcanos,³ and aquifer flow.^{4,5}

Seismic reflection is widely used to monitor CO₂ storage sites.⁶ Like the gravity method, seismic reflection is more likely to detect CO₂ gas plumes in shallow aquifers, where the density contrast between CO₂ gas and brine is significantly larger than that between supercritical CO₂ and brine in a deep storage reservoir. Yang et al.⁷ used the workflow of Wang et al.⁸ to construct seismic velocity models for flow simulations of CO₂ and brine leakage from a hypothetical GCS operation. They built a layered, baseline, velocity model by applying Gassmann's equations at the initial temperature, pressure, and TDS conditions in the flow simulations. In the absence of geologic information from well logs, they assumed all layers in the overlying aquifers were 70% quartz and 30% clay by volume to model the signal. The bulk and shear moduli of the mineral grains were calculated by taking the arithmetic average of the upper and lower Hashin-Shtrikman bounds of the mineral constituents.⁹ Yang et al. determined that the seismic-reflection method is nearly as effective as the gravity method in detecting shallow CO₂ leaks.¹⁰

Unlike GCS, where a relatively dense (supercritical CO₂) fluid is injected, UHS will always involve the injection of a low-density (H₂/CH₄) gas. The large density contrast between the H₂/CH₄ gas and formation brine or groundwater enables the gravity and seismic-reflection methods to monitor relatively deep H₂/CH₄ gas-leakage plumes as well as shallow H₂/CH₄ plumes. For the injection of H₂/CH₄ gas in saline aquifers, mass-density changes strongly depend on the distribution of the non-wetting (H₂/CH₄) gas phase, as it displaces the wetting (brine) phase in the porous rock. The density of H₂/CH₄ gas mixtures depends strongly on the volumetric fraction of H₂ in the mixture, as well as temperature and pressure, which depend on the geothermal and hydrostatic pressure gradients. Figure 3.6 shows the dependence of the H₂/CH₄ gas-to-water mass-density ratio on the volume fraction of H₂, temperature, and pressure.

¹ J.F. Ferguson et al., "The 4D microgravity method for waterflood surveillance: Part 3 -4D absolute microgravity surveys at Prudhoe Bay, Alaska."

² J.L. Hare et al. "The 4D microgravity method for waterflood surveillance: Part IV - Modeling and interpretation of early epoch 4D gravity surveys at Prudhoe Bay, Alaska."

³ M. Battaglia et al., "4D volcano gravimetry."

⁴ K. Davis et al., "Time-lapse gravity monitoring: A systematic 4D approach with application to a quifer storage and recovery."

⁵ L. Christiansen et al., "Measuring gravity change caused by water storage variations: Performance assessment under controlled conditions."

⁶ H. Alnes et al., "Monitoring gas production and CO₂ injection at the Sleipner field using time-lapse gravimetry."

⁷ Yang et al., "Assessment of geophysical monitoring methods for detection of brine and CO₂ leakage in drinking water aquifers."

⁸ Wang et al.

⁹ Z. Hashin, and S. Shtrikman, "A variational approach to the theory of the elastic behaviour of multiphase materials."

¹⁰ X.J. Yang et al., "Assessment of geophysical monitoring methods for detection of brine and CO₂ leakage in drinking water aquifers."

5.4 Downhole Monitoring of Chemistry and Pressure

Near-surface groundwater chemistry is routinely monitored by downhole sampling to assess the impact of CO₂ leakage on water quality.^{1,2} While downhole chemical monitoring provides direct information on water quality, it has limited spatial coverage, requiring many monitoring wells.³ Field studies⁴ and related modeling studies⁵ suggest that dissolved inorganic carbon concentration is an effective indicator of leakage, in part because real-time, fiber-optic sensors can be used. Deploying monitoring wells is expensive, so the EPA recommends that monitoring wells be placed strategically to maximize the monitoring well network's ability to detect potential leakage and track the migration of the TDS and pressure plumes.⁶

Pressure monitoring in the above-zone monitoring interval (AZMI) immediately above the confining zone near the injection well has been proposed as an effective way to detect leakage before USDWs have been compromised.^{7,8,9} A comparison of pressure and chemical monitoring in the AZMI¹⁰ indicated that pressure monitoring is more effective than chemical monitoring. To detect leaks in drinking water aquifers, downhole pressure measurements provide an integrated signal that samples over larger areas and may not require as many wells as chemical sampling.¹¹ Buscheck et al. determined that the combined use of pressure and chemical monitoring is more effective for early leak detection than using either pressure or chemical monitoring alone.¹²

For pressure and TDS monitoring, a key metric is the accuracy threshold, which refers to whether the measured changes can be distinguished from background noise.¹³ For pressure monitoring, in the absence of background noise and gauge drift, Zeidouni and Pooladi-Darvish¹⁴ found that available quartz gauges provide a high-quality pressure signal with a 70 Pa resolution. While periodic barometric and tidal signals

¹ Y.K. Kharaka et al., "Changes in the chemistry of shallow groundwater related to the 2008 injection of CO₂ at the ZERT field site, Bozeman, Montana."

² A.G. Cahill, and R. Jakobsen, "Hydro-geochemical impact of CO₂ leakage from geological storage on shallow potable aquifers: A field scale pilot experiment."

³ S.A. Carroll et al., "Key factors for determining groundwater impacts due to leakage from geologic carbon sequestration reservoirs."

⁴ S.B. Yang et al., "Field demonstration of CO₂ leakage detection in potable aquifers with a pulse like CO₂-release test."

⁵ H.X. Bie et al., "Assessing groundwater monitoring strategy for leakage detection in the Texas Gulf Coast Aquifer (USA) at a hypothetical CO₂ storage site: a reactive transport modeling approach."

⁶ T.A. Buscheck et al. "Downhole pressure and chemical monitoring for CO₂ and brine leak detection in aquifers above a CO₂ storage reservoir."

⁷ A.Y. Sun, and J.P. Nicot, "Inversion of pressure anomaly data for detecting leakage at geologic carbon sequestration sites."

⁸ S. Kim, and S.A. Hosseini, "Above-zone pressure monitoring and geomechanical analyses for a field-scale CO₂ injection project in Cranfield, MS."

⁹ Zhang et al.

¹⁰ Bie et al.

¹¹ W. Trainor-Guitton et al., "Merits of pressure and geochemical data as indicators of CO₂/brine leakage into a heterogeneous, sedimentary aquifer."

¹² Buscheck et al.

¹³ G.V. Last et al., "Derivation of groundwater threshold values for analysis of impacts predicted at potential carbon sequestration sites."

¹⁴ M. Zeidouni, and M. Pooladi-Darvish, "Leakage characterization through above-zone pressure monitoring: 1-Inversion approach."

can be filtered out,¹ site-specific anthropogenic sources of noise are more difficult to remove. Therefore, pressure monitoring should begin prior to injection to determine background noise.² The compilation of observed decadal-scale TDS variations in the United States is a useful guide for determining appropriate accuracy thresholds for TDS monitoring.

These methods can be translated to H₂/CH₄ storage wells with sensors for H₂ and CH₄ monitoring. As the downhole conditions are more complex than the conditions above the ground, sensors need to be robust and stable for subsurface conditions and compatible with flammable conditions.

5.5 Hydrogen Seismicity Monitoring

The majority of earthquakes are tectonic (resulting from natural causes), but under some circumstances human activities can trigger seismicity. Induced seismicity has been attributed to a broad range of human activities, including underground injection, such as wastewater disposal, and oil and gas extraction. While the majority of wastewater disposal operations do not pose a hazard for induced seismicity, several in the central and eastern U.S. have led to four earthquakes larger than magnitude 5 since 2008.

Understanding induced seismicity requires knowledge about the relationship between fluid injection and withdrawal activities and the activation or reactivation of faults, including the relationship between spatial and temporal pore-pressure changes and optimally-oriented, critically-stressed faults.^{3,4} Because the same basic physics govern tectonic and induced earthquakes, it is possible to apply much of the established earthquake science to understanding induced seismicity related to UHS.

It is important to note the distinct differences between wastewater disposal and UHS. Wastewater disposal injects an incompressible fluid that results in a continuous increase in pore pressure, while UHS involves cyclic injection and withdrawal of very low-density, compressible fluids (H₂ and CH₄) that result in pore-pressure increase and decrease. Nonetheless, it is useful to consider the experience of wastewater disposal and induced seismicity to inform risk management and mitigation strategies for UHS operations.

Experience with induced seismic events at UGS facilities is very limited. Of the more than 640 UGS facilities operating worldwide, with 420 of them in the United States, only one has been shut down due to seismic concerns, the Castor Project off the coast of the Valencia Gulf, Spain. In addition to the Castor Project, there are documented examples of induced seismicity at UGS facilities in The Netherlands and in China.

Induced seismicity is best monitored and managed using microseismic arrays capable of detecting and locating small-magnitude events. There is significant experience in seismic monitoring and risk management in the oil and gas, wastewater disposal, and CO₂ storage domain that can be applied to seismically problematic gas storage operations.

Natural tectonic seismicity may also pose a threat in certain regions. For example, some gas fields in California have wells that penetrate larger faults. Slip on these faults could potentially damage well casings. Similarly, large seismic events could damage surface infrastructure via direct shaking, triggered landslides, tsunami events, or similar hazards.⁴

¹ K. Sato, “Monitoring the underground migration of sequestered carbon dioxide using Earth tides.”

² Buscheck et al.

³ Buscheck et al.

⁴ K.A. Kroll et al., “Testing the efficacy of active pressure management as a tool to mitigate induced seismicity.”

⁴ Long et al.

6.0 Social License to Operate for Subsurface Hydrogen Storage

6.1 Overview

While there is a general need to advance public perception of hydrogen as a viable energy carrier, gaining public acceptance to store large quantities of hydrogen in the subsurface faces particular opportunities and challenges.¹ Indeed the entire enterprise of changing energy systems – to reduce reliance on fossil fuels or to maintain energy stability and independence using a broad portfolio of energy sources – requires significant public acceptance.²

To advance the social license to operate, we must understand the key stakeholders, who have specific concerns and needs, and proactively engage with them to improve the public perception and gain acceptance for deployment of this technology. Here, a stakeholder is defined as a group of people with interest, involvement, or investment in an activity of concern.³ Logical stakeholder groups for UGS could be operators, regulators, early adopters, potential end users, populations proximal to a UGS site, or the general public. These stakeholders need not be distinct and may have differing or even conflicting views, needs, and concerns.

As with any new technology, there is a risk for rejection based on misinformation or inadequate explanation of the cost-benefit tradeoff for a specific stakeholder, and some value propositions may be appealing for one stakeholder but not another. For example, the added value of hydrogen sourced from renewable technologies may be appealing to some, but not all, depending on their specific concerns (e.g., in a community where fossil fuels provide a historical source of employment).

6.2 Current Perception of Underground Storage of Hydrogen

There is almost no data on public perception of UHS. There have been studies on public perception of hydrogen but they focused on hydrogen-transportation technology, above-ground storage, and mostly on aspects that would impact general acceptance of hydrogen as an energy carrier (e.g., costs, benefits, risks, environmental impacts).⁴ Even these studies showed a general low public awareness of hydrogen in Western Europe, which is likely also true for the United States.

Pilot demonstration studies, when properly communicated and executed, represent an opportunity to advance public acceptance. This may require intense engagement with key stakeholders, in coordination with regulators and operators, to understand their needs and concerns and tailor the communication of risk and the value proposition for this technology. To communicate risks and demonstrate safe operations, additional data that is properly convened may be needed to build public trust. For example, a pilot study may need a more intensive monitoring program to demonstrate that the operations are occurring according to model expectations and within regulatory compliance. This may run counter to operator expectations but would have an overall benefit to technology acceptance by improving public perception and awareness.

¹ N.V. Emodi et al., “A systematic literature review of societal acceptance and stakeholders' perception of hydrogen technologies.”

² P. Upham et al., “Towards a cross-paradigmatic framework of the social acceptance of energy systems.”

³ Emodi et al.

⁴ Emodi et al.

6.2.1 Lessons learned from analogous industries

Existing NG storage fields are attractive candidates for early adoption of subsurface hydrogen storage technologies as the risks have been well studied and successful NG storage operations have been conducted for decades. Figure 6.1 and Figure 6.2 show existing NG infrastructure in terms of existing pipelines and subsurface storage facilities along with potential hydrogen production from both fossil fuels and renewable sources. The concept of underground hydrogen storage can leverage decades of experience storing NG and helium¹ in understanding the occurrences of leakage, events, incidences, accidents, or failures.² Hydrogen is more challenging in that it is more likely to escape the storage system due to its smaller molecule size, higher buoyancy, and lower viscosity than NG.

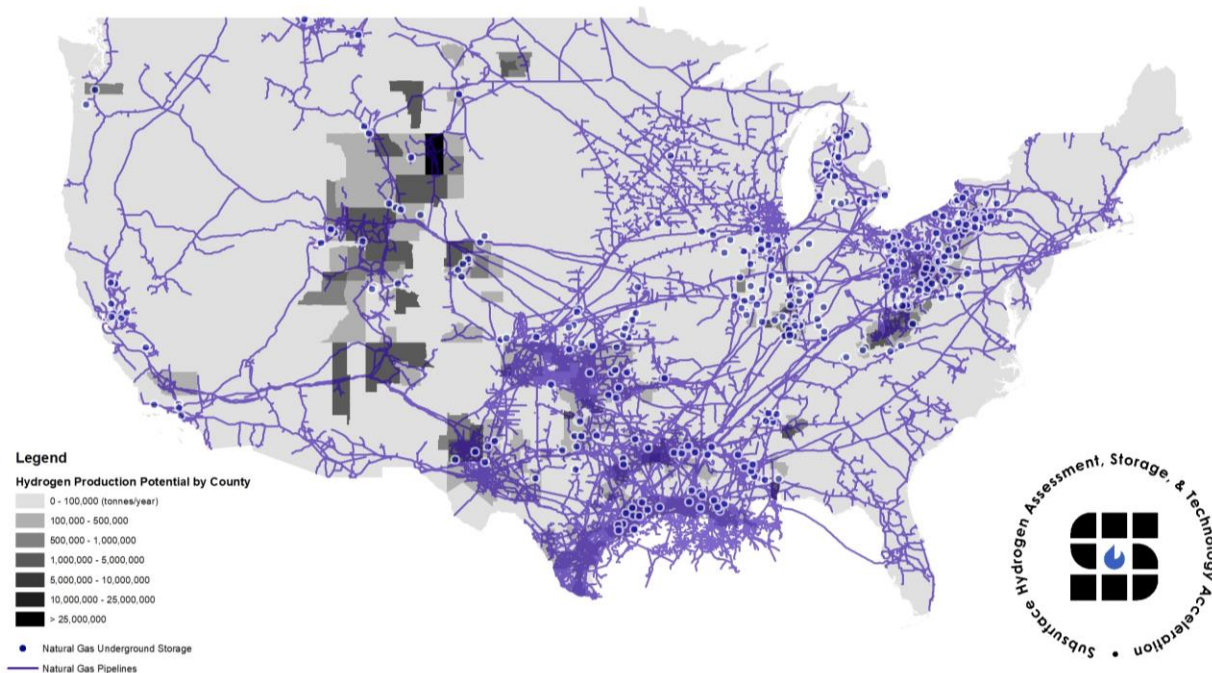


Figure 6.1. Map showing the existing natural gas infrastructure [pipelines (purple lines) and subsurface storage facilities (purple filled circles)] and the hydrogen production potential from 100% utilization of fossil and nuclear energy sources (shaded regions in gray) binned by county. Data sources: https://www.eia.gov/maps/layer_info-m.php; <https://maps.nrel.gov/hydra/>

¹ Zivar et al.

² R.A. Schultz, and D. J. Evans, "Occurrence frequencies and uncertainties for US underground natural gas storage facilities by state."

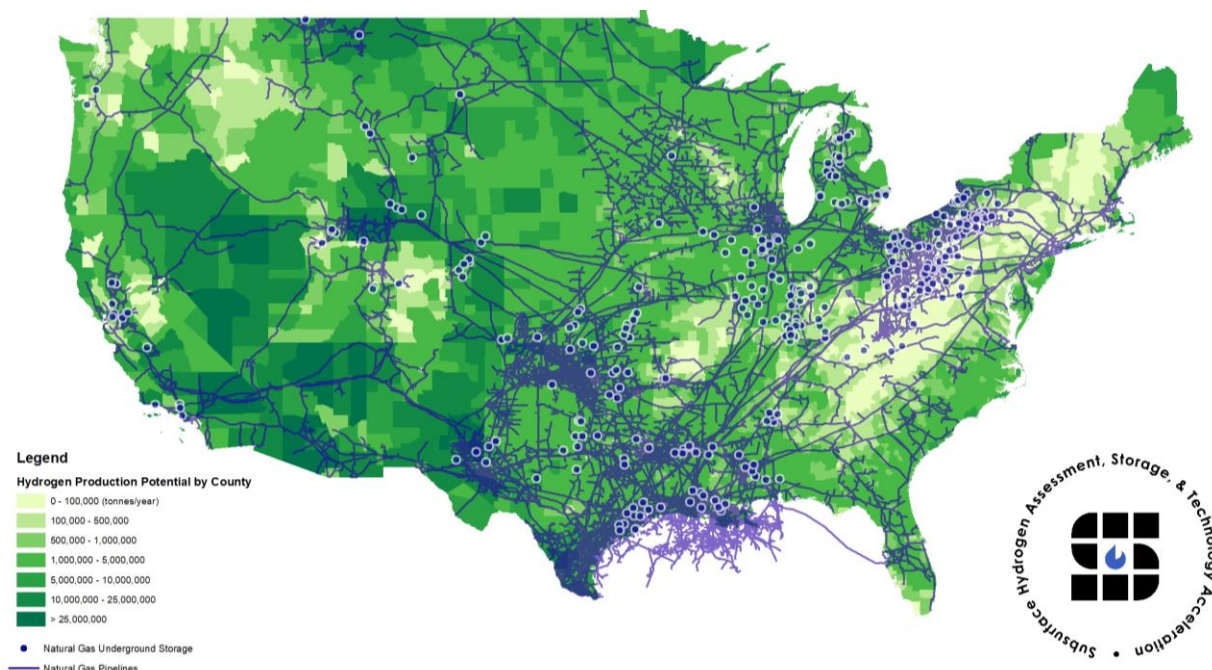


Figure 6.2. Map showing the existing natural gas infrastructure [pipelines (purple lines) and subsurface storage facilities (purple filled circles)] and the hydrogen production potential from wind, solar, biomass, and hydropower (shaded regions in green) binned by county. Data sources: https://www.eia.gov/maps/layer_info-m.php; <https://maps.nrel.gov/hydra/>

Even geothermal energy production, which is generally considered an attractive renewable energy system, is not without risk from public backlash.¹ The Pohang geothermal site in South Korea was seen as an opportunity for the local community to gain economic prosperity and nationally as one of several projects aimed at mitigating Korea's impact on climate change. When a magnitude 5.4 earthquake was induced as a result of enhanced geothermal system water injections, there was significant damage to thousands of buildings and injuries in the local community. The resulting backlash not only affected the prospect of a geothermal site but also the prospect of a GCS project in the same area, assumedly because of the similarities in drilling and injection. Thus, communication should focus on the benefits and the risks, specifically aimed at the key stakeholders (here the local populace), of any given energy system.

Deployment of wind turbine projects often faces opposition where local concerns such as perceived health hazards, impacts to wildlife, or property devaluation create more discontent than the global environmental benefits.²

6.3 Opportunities to Improve Perception and Acceptance

One strategy to improve public perception and acceptance may be to demonstrate that UHS is not a new technology but is an augmentation of existing NG storage technologies. Approaching this as a gradual blending of hydrogen with existing NG may allow time for end users to gain comfort with the new energy carrier and allow the energy grid to adapt to this new technology in end use applications.

¹ H. Baek et al. "Differences in public perceptions of geothermal energy based on EGS technology in Korea after the Pohang earthquake: National vs. local."

² M.A. Petrova, "From NIMBY to acceptance: Toward a novel framework - VESPA - For organizing and interpreting community concerns."

A market analysis of the value proposition for the local populace is key for public acceptance. Stakeholders should not be considered as a barrier but as a resource for effective design and deployment of a hydrogen infrastructure.¹ Engagement with non-expert interested parties can elicit risks and concerns not considered by experts but that may be a real or perceived obstacle to technology acceptance and project success.²

Novel frameworks that factor in VESPA (visual, environmental, socioeconomic, and procedural) aspects to examine stakeholder concerns,³ especially at the local level, could be used to develop communication strategies tailored to specific stakeholder needs and concerns. Community acceptance should then be sought using a framework like “ENUF,” which emphasizes⁴:

- *Engage* the local community throughout the life of the project and involve them in the decision-making process through public forums.
- *Never use NIMBY (Not In My Back Yard)* as this is a pejorative term and an oversimplification of the concerns of the stakeholders.
- *Facilitate* communication with the local community to empower them to design and carry out their own energy choices.

The Subsurface Hydrogen Assessment, Storage, and Technology Acceleration (SHASTA) project provides an opportunity to conduct a pre-and post-pilot test analysis to examine if and how we move the needle with proactive community engagement.

6.3.1 Business and regulatory setting

6.3.1.1 Regulatory environment

The regulatory environment for subsurface H₂ storage in existing underground gas storage facilities or geological formations that are not currently used for gaseous storage might closely resemble the existing regulatory structure of NG storage. NG storage facilities are typically regulated either at the state or federal level, with larger facilities often falling under federal purview because of their engagement in interstate commerce.⁵

New construction and pricing power for large storage field operators is regulated by the Federal Energy Regulatory Commission (FERC). For operators seeking to modify existing facilities or place new wells into operation to store blended H₂ and NG, FERC may oversee the approval, permitting, and siting processes for any new facilities that are to be interconnected with the NG pipeline system. FERC is charged with determining if the proposed storage facilities are a “public convenience and necessity” and, based on this criterion, can stipulate approval conditions for a facility that may alter project characteristics such as interconnection lateral routing or other aspects.⁶ FERC also conducts in-depth reviews of the pricing and rates that storage providers charge their customers. For pricing power, FERC is empowered to ensure that providers are charging “just and reasonable” rates.⁷

¹ Emodi et al.

² A.L. Israel et al., “Eliciting public concerns about an emerging energy technology: The case of unconventional shale gas development in the United States.”

³ Petrova

⁴ Petrova

⁵ INGAA, “How are pipelines regulated?”

⁶ INGAA

⁷ INGAA

For smaller storage fields that support single NG distribution systems that do not cross state lines, state public utility commissions (PUCs) perform many of the functions that FERC does for large facilities. For these smaller facilities, the PUCs conduct reviews of the “public convenience and necessity” and “just and reasonable” rate criteria.

Safety of underground storage facilities is regulated by a combination of government agencies and fire authorities. Safety regulation of large storage fields that conduct business across state lines is delegated to the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA is responsible for enforcing pipeline safety-related statutes in the *Code of Federal Regulations* and responds to large safety incidents with an in-depth root cause analysis investigation and penalty authority. PHMSA is also directly involved in rulemaking activities to advance safety goals and would likely gain jurisdiction over safety regulation of subsurface H₂ storage facilities. PHMSA works closely with each state’s pipeline safety department within their PUC and has a limited role supporting the administration of each state’s safety program. At the state level, underground storage facility safety is regulated according to both PUC and fire marshal regulations for storage of flammable materials.

Environmental regulation of UGS facilities storing NG, and likely large facilities storing blended NG and H₂, is under the purview of the EPA and state departments of environmental protection (DEPs). Siting, design, construction, and operation of UGS are influenced by environmental regulations designed to protect the air, land, water, and wildlife. A few examples of statutes that the EPA and DEPs are responsible for administering and enforcing for UGS are the National Environmental Policy Act of 1969, Federal Water Pollution Control Act (“Clean Water Act”), Coastal Zone Management Act, Endangered Species Act, Clean Air Act, and National Historic Preservation Act.¹ The regulatory environment in the U.S. can also spur development of UGS of H₂ and blended H₂/CH₄ through Renewable Portfolio Standards.

6.3.1.2 Business case

Research approaches to assessing the business case for storing H₂ in UGS typically take two approaches: (1) a discussion and estimation of the costs associated with each type of UGS option and/or (2) an enumeration and discussion of the demand for H₂ in the greater energy landscape. The recent literature concludes that, in general, the costs associated with constructing UGS facilities are lower than their above-ground counterparts that have comparable capacity.² Peng et al. conducted a literature survey that articulated that the costs of UGS come from reservoir operation, injection/extraction wells, above-ground equipment, and energy purchased for operations and maintenance.³ These costs can be minimized if wells selected to store H₂ underground are subjected to a basic set of screening criteria. These selection criteria fall within technical and economic categories and help identify the types of gas storage facilities that are economically viable as H₂ UGS.

According to Tarkowski, the basic technical selection criteria for identifying a viable storage facility for H₂ include structure depth; thickness; tightness of formation, borehole(s) properties, transporting pipelines, and roof rocks; reservoir pressure and fracture pressure; reservoir porosity and permeability; geo-mechanical properties; and proper characteristics of the insulating roof rocks.⁴ Tarkowski also identifies two key economic selection criteria: construction cost-effectiveness and the distance of the storage facility from mainline pipelines that would off-take the stored products.⁵ The construction cost-

¹ INGAA

² Tarkowski, “Underground hydrogen storage: Characteristics and prospects.”

³ Peng et al.

⁴ Tarkowski, “Underground hydrogen storage: Characteristics and prospects.”

⁵ Tarkowski, “Underground hydrogen storage: Characteristics and prospects.”

effectiveness criteria include an assessment of the existing balance of system equipment at a potential storage facility site (including gas processing and interconnection equipment), site development limitations (presence of protected environmental areas, brine disposal logistics, technological water availability), and local community impacts. The distance of the storage facility from mainline pipelines could also consider the economic needs of the energy market in the area that the storage facility is being assessed for. Overall, Tarkowski's review of the relevant literature concludes that the most cost-effective UHS option on a capital cost basis is depleted hydrocarbon reservoirs at approximately \$1.23/kg of stored H₂, followed by aquifers at \$1.29/kg, then salt caverns at \$1.61/kg and hard rock caverns at \$2.77/kg.¹ These values are fairly uncertain and are likely to become more concrete as additional studies and field deployment occur, especially for the less mature technologies.

When identifying which storage facilities are most cost effective, there are several obstacles that need to be overcome for demand for H₂ products to make widespread adoption of the technology more likely.

Currently, it is not profitable to sell hydrogen blends at the same price as NG because clean hydrogen is more expensive to produce than NG. It costs \$5-\$7/kg (\$37-\$62/MMBTU) today to produce hydrogen by electrolysis. In comparison, the nationwide average price for NG in 2010-2012 was \$3.7/MMBtu. Recent studies based on those same 2010-2012 NG prices have suggested that if utilization rates of electrolyzers are high⁴ and a premium of approximately 16% was added to the cost of NG,⁵ UHS might achieve profitability.² One study estimates that for profitability to be achieved if H₂ offtake is completed using the NG market, a premium of approximately 16% would need to be added to the cost of NG based on 2010-2012 nationwide average prices (\$3.7/MMBtu).³

High utilization rates for electrolyzers could be driven by the market size for pure H₂ depending on the system configuration and where electrolysis and separation occurs. The literature identified the following five key categories of demand segments for H₂ or blended H₂ products: heavy industry, power generation, H₂ vehicles,^{4,5} and areas with large differences between summer and winter heat production.⁶ For instance, pure H₂ is used in factories that produce ammonia and methanol, and oil refineries for process use. Factories that currently use NG for heat or power applications could use H₂ blends. A special use case for UHS is illustrated at a Praxair Texas facility, which directly uses UHS as a means to "peak shave" its on-demand pure H₂ production schedule in support of nearby petrochemical facilities in Texas and Louisiana. H₂ storage demand could also be driven by areas of the country with historical precedent of large variable energy generation curtailments such as Texas.⁷ During times of curtailment, wind or solar could be used to produce and store H₂ using electrolyzers.

The literature summarizes more detailed business considerations for each of the potential storage types: depleted NG deposits, aquifers, and salt caverns. Depleted deposits and aquifers appear most frequently in literature discussions related to economic viability of UGS of H₂ because those facilities are common throughout the world and have large storage capacity potential – perhaps large enough that one field could supply a large region or an entire country.⁸ The business case for using depleted hydrocarbon deposits to store H₂ underground is typically centered on the fact that those facilities often already have equipment in

¹ Tarkowski, "Underground hydrogen storage: Characteristics and prospects."

² Tarkowski, "Underground hydrogen storage: Characteristics and prospects."

³ Peng et al.

⁴ Peng et al.

⁵ Tarkowski, "Underground hydrogen storage: Characteristics and prospects."

⁶ Mouli-Castillo et al.

⁷ Tarkowski, "Underground hydrogen storage: Characteristics and prospects."

⁸ Mouli-Castillo et al.

place for injection and withdrawal, processing, and interconnection with pipelines.¹ This reduction in capital cost makes depleted deposits favorable compared to cavern-type facilities. Depleted reservoirs do, however, require special consideration of borehole casings and materials, which might not be as important for other types of UGS.² Further special considerations for reservoirs include planning for declining extraction rates and low NG prices in the U.S. These trends might work together with low-carbon policy goals to open other fields to the potential of storing H₂ in the 2040 timeframe and beyond. The authors of the same study also highlight that depleted reservoirs used for storage may also hold an advantage over other types of UGS because they are often already connected to NG terminals that help move gas directly to end users.^{3,4,5}

A special business case advantage for saline aquifer-based H₂ UHS that appears in the literature may be related to the geographic proximity of identified aquifers to major population centers and energy consumers.⁶ This advantage might be offset if there is not ready access to the pipeline system near the aquifer access point or developable land nearby for aboveground equipment. As discussed in Section 3.1.5, CO₂ for carbon storage may be used as a cushion gas during saline aquifer-based H₂ storage that may qualify for tax credits.

Of all “underground working” types of storage alternatives, the construction costs are reportedly lowest for salt caverns.⁷ For cavern-based UGS, shallow site costs are dominated by cavern construction costs while deep storage site costs are dominated by surface equipment installation – mainly gas compressors.⁸

¹ Tarkowski, “Underground hydrogen storage: Characteristics and prospects.”

² Tarkowski, “Underground hydrogen storage: Characteristics and prospects.”

³ Mouli-Castillo et al.

⁴ R.L. Wallace et al., “Utility-scale subsurface hydrogen storage: UK perspectives and technology.”

⁵ Muhammed et al.

⁶ Tarkowski, “Underground hydrogen storage: Characteristics and prospects.”

⁷ Tarkowski, “Underground hydrogen storage: Characteristics and prospects.”

⁸ D. Gammer, “The role of hydrogen storage in a clean responsive power system.”

7.0 Recommendations

To achieve industrial-scale underground H₂ storage in support of a nationwide transition to an H₂-rich energy infrastructure, significant technological advancements are needed that build on existing knowledge from analog systems and leverage the existing NG infrastructure. Fundamental research into subsurface flow behavior, biogeochemical processes, and materials performance is needed as a basis for more applied technical challenges. These challenges relate to an UHS site's operational conditions, risk assessment/mitigation, and overall acceptance of this technology among operators, regulators, and stakeholders. Critical on the technology commercialization pathway are pilot-scale studies, which are increasingly influenced by public perception and energy equity issues. DOE could play a pivotal role in UHS technology development toward commercialization by advancing the scientific understanding of fundamental processes, advancing technologies, and communicating our findings to key stakeholders. Below are the recommendations, based on this report's exhaustive analysis of the present state of knowledge and the key thrusts SHASTA is addressing, that would significantly accelerate the technology's maturation and acceptance.

- Characterize well integrity for compatibility with hydrogen and any biogeochemical interactions that may degrade system components (e.g., metals, cement, and elastomers). Select experiments should be used to fill in the gaps between what we already know about well materials performance with H₂ and UGS operations and experience, leveraging existing knowledge, knowledge being generated by other DOE efforts, and knowledge from analogous systems. Research should focus on first understanding if existing wells are compatible and then, if not, research and development related to mitigation of existing wells and new H₂-compatible materials.
- Assess the biogeochemical impacts of H₂ in the subsurface at conditions expected for UGS, and specifically focus on any deleterious impacts from abiotic/biotic reactions on asset loss, unwanted reservoir property alteration, and wellbore degradation.
- Work with regulators, industry, key stakeholder groups, and other government entities to make DOE's efforts the most impactful. Communicate the findings through scientific publications and recommended practices manuals. Make the products useful for a full range of interested parties:
 - Regulators – Understand the science base needed by regulators when crafting any new regulations or guidance documents.
 - Industry – Develop protocols and recommended practices so that industry can take over site assessment and screening activities as this technology emerges.
 - Key stakeholder groups – Advance the nation's understanding of the value proposition for hydrogen and the need for UHS. Work with them at any pilot sites to guide the development of their energy portfolio.
 - Interagency coordination – Coordinate and collaborate with other state and federal agencies when possible and share data for their mission needs.
- Develop a constitutive understanding of the multiphase/multicomponent flow behavior of H₂ and H₂/NG blends in the presence of brine by conducting laboratory and numerical simulation studies using relevant geologic materials and conditions.
- Develop modeling tools, informed by the fundamental scientific understanding, that enable operators, regulators, and stakeholders to make informed decisions. Specifically, the following tools would be of high impact:
 - A tool that accurately simulates the fate and transport of multiphase/ multicomponent hydrogen systems at the reservoir scale. This tool would, for example, allow an operator to develop

operational programs for storage and recovery, assess their assets, and demonstrate an understanding of the subsurface state to maintain regulatory compliance and stakeholder acceptance.

- A tool that rapidly estimates the capacity, deliverability, and storability of H₂ and H₂/NG blends for candidate sites. This tool could be used by industry or policy makers to rapidly assess the storage potential for their assets or region of interest.
- A tool that enables the technoeconomic analysis of subsurface H₂ storage for one or more sites. This tool could be used by industry or policy makers to rapidly assess the value proposition of UHS in their systems and would tie into other larger analytical tools being developed by DOE.
- Develop novel gas sensing, leak detection, and well integrity sensors to improve well surveillance at acceptable costs.
- Develop one or more pilot demonstration tests in the next 3-5 years.
 - In conjunction with industry and regulators.
 - Focus on public acceptable and energy equity.

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