



جامعة الملك عبد الله  
للعلوم والتقنية  
King Abdullah University of  
Science and Technology

## Toward a Fundamental Understanding of Geological Hydrogen Storage

Item Type	Article
Authors	Aftab, Adnan; Hassanpouryouzband, Aliakbar; Xie, Quan; Machuca, Laura L.; Sarmadivaleh, Mohammad
Citation	Aftab, A., Hassanpouryouzband, A., Xie, Q., Machuca, L. L., & Sarmadivaleh, M. [2022]. Toward a Fundamental Understanding of Geological Hydrogen Storage. Industrial & Engineering Chemistry Research. <a href="https://doi.org/10.1021/acs.iecr.1c04380">https://doi.org/10.1021/acs.iecr.1c04380</a>
Eprint version	Post-print
DOI	<a href="https://doi.org/10.1021/acs.iecr.1c04380">10.1021/acs.iecr.1c04380</a>
Publisher	American Chemical Society (ACS)
Journal	Industrial & Engineering Chemistry Research
Rights	This document is the Accepted Manuscript version of a Published Work that appeared in final form in [JournalTitle], copyright © American Chemical Society after peer review and technical editing by the publisher. To access the final edited and published work see [ArticleLink].; This file is an open access version redistributed from: <a href="https://www.pure.ed.ac.uk/ws/files/266540998/Aftab_et_al._Accepted_Manuscript.pdf">https://www.pure.ed.ac.uk/ws/files/266540998/Aftab_et_al._Accepted_Manuscript.pdf</a>
Download date	01/10/2023 16:44:28
Link to Item	<a href="http://hdl.handle.net/10754/675545">http://hdl.handle.net/10754/675545</a>

# Towards a fundamental understanding of geological hydrogen storage

Adnan Aftab<sup>1,2,3\*</sup>, Aliakbar Hassanpouryouzband<sup>4</sup>, Quan Xie<sup>1</sup>, Laura L. Machuca<sup>5</sup>,  
Mohammad Sarmadivaleh<sup>1\*</sup>

<sup>1</sup>Curtin University, Discipline of Petroleum Engineering, 26 Dick Perry Avenue, 6151  
Kensington, Australia

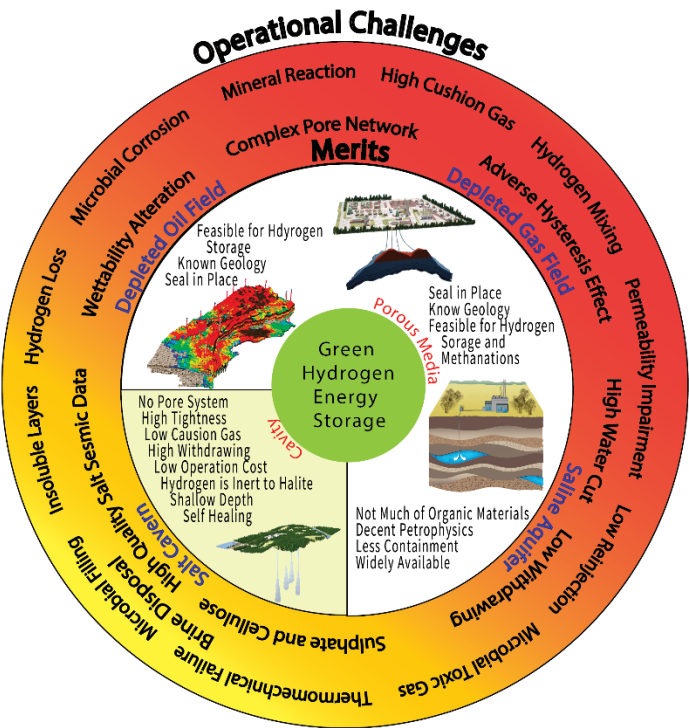
<sup>2</sup>Petroleum Engineering Department, Mehran UET, SZAB, Khairpur Mir's Campus, 66020  
Sindh, Pakistan Pakistan

<sup>3</sup>Energy Resources and Petroleum Engineering, King Abdullah University of Science and  
Technology KAUST, Thuwal, 23955-6900, Saudi Arabia

<sup>4</sup>School of Geosciences, University of Edinburgh, Grant Institute, West Main Road,  
Edinburgh EH9 3FE, U.K.

<sup>5</sup>Curtin Corrosion Centre, Curtin University, Bentley, Western Australia 6102, Australia

Corresponding Emails: [adnan.aftab@postgrad.curtin.edu.au](mailto:adnan.aftab@postgrad.curtin.edu.au)  
[mohammad.sarmadivaleh@curtin.edu.au](mailto:mohammad.sarmadivaleh@curtin.edu.au)



29

30    This review is unique in its presentation and reported distinctive information which could  
31    attract scientific community to devise an optimized plan for geological hydrogen storage  
32    industry.

33

## Abstract

Geological  $H_2$  storage plays a central role to enable the successful transition to the renewable  $H_2$  economy and achieve net-zero emission in the atmosphere. Depleted oil and gas reservoirs are already explored with extensive reservoir and operational data. However, residual hydrocarbons can mix with injected  $H_2$  in the reservoirs. Furthermore, low density and high diffusivity of  $H_2$  may establish  $H_2$  leakage from the reservoirs via fault pathways. Interestingly,  $H_2$  can be consumed by microorganisms, which results in pore-network precipitation, plugging and partial permeability impairment. Therefore, stored  $H_2$  may be lost in the formations if storage scenario is not planned cautiously. While salt caverns are safe and commercially proven geo-rock for  $H_2$  storage, they have low-storage capacity compared to depleted gas reservoirs. Moreover, salt structures (e.g., dome, bedded) and microorganisms activities in the salt cavern are limiting factors, which can influence the storage process. Accordingly, we discuss challenges and future perspectives of hydrogen storage in different geological settings. We also highlight geographical limitations with diverse microbial communities and theoretical understanding of abiotic transformation (in terms of rock's minerals i.e., mica, and calcite) for geological  $H_2$  storage. Regarding the fundamental behavior of  $H_2$  in the geological settings, it is less soluble in formation water, therefore it may achieve less solubility trapping compared to  $CO_2$  and  $CH_4$ . Furthermore,  $H_2$  gas could attain higher capillary entrance pressures in porous media over  $CH_4$  and  $CO_2$  due to higher interfacial tension. Additionally, the low viscosity of  $H_2$  may facilitate its injection and production but  $H_2$  may establish the secondary trapping and viscous fingering. Thus, this review documented a blend of key information for the amendment of subsurface  $H_2$  storage at an industrial scale.

**Key words:** Energy transformation, Hydrogen, geological, storing, reproducing, net-zero

## 1 Introduction

In 2020, the world's primary energy consumption and carbon emissions from energy use are declined by 4.5% and 6.3%, respectively. This was mainly pushed by a record reduction in oil consumption (9.1 million barrels per day) and considerable falls in natural gas use by 2.3%<sup>1</sup>. In contrary to this, the energy demand growth rate was positive in 2019<sup>2</sup>. The rise of COVID-19 and the uncertain schedule of partial/full lockdowns constrained the economical growth<sup>3</sup> which results in a decline in the global demand for coal (down to 1.7 %) in 2019<sup>2</sup>. Moreover, the demand for natural gas decreased to 2%, and oil demand reduced to 20% in 2020 Q1<sup>4</sup>. Overall,  $CO_2$  emission went down (which was 2.1% in 2018, and 0.5% in 2019) due to the massive impact of COVID-19 onto the consumption of fossil fuels around the globe. The negative trend of  $CO_2$  emission was observed in different regions such as Europe (-8%), China (-8%), and US (-9%)<sup>2</sup>. Nevertheless, the global primary energy demand is 84% and still would be delivered by fossil fuels.  $CO_2$  emission growth by 0.5 % cannot be persistent anymore because developed nations will once again gain momentum to retain their position in the global energy supply market<sup>2</sup>.

European Union Energy Security and Strategy (EUESS) affirmed that the suppression of greenhouse gases down to 20 to 30% by 2020 is key to protect climate change and environment. Therefore, there is a pressing need to increase the participation of renewable energy to 20% in the primary global energy demand<sup>5</sup>. Additionally, Energy Road Map Goals (ERMG) 2050 set objectives to mitigate greenhouse gases emission (GHGE) by 80 to 95%<sup>6</sup>. Consequently, renewable energy production would be given a priority and 55% of energy would be projected to produce from renewable energy systems alone in Europe by 2050<sup>5</sup>. Additionally, South-East Asia has projected to achieve the 35 to 40 GW (35%) of renewable energy target by 2025 using wind and solar energy's lower costs<sup>7</sup>. In 2020, the US has grown renewable energy consumption, reaching a record high 12% of the total US energy demand<sup>8</sup>. Renewable energy sources are found better with diverse applications<sup>9</sup>, in particular, minimum electricity bills<sup>10</sup>, and low maintenance costs<sup>11</sup>. For example., solar system is the green transformation of energy from sunlight into power through direct photovoltaic effect or concentrated solar power system<sup>12</sup>. Additionally, the energy from the sun would not run out unlike fossil fuels and it provides more heat energy than our need<sup>13</sup>. Moreover, solar

energy can be produced without emitting  $CO_2$  for commercial production of electricity <sup>14, 15</sup>. In the same line, researchers have a concentrated focus on the utilization of wind energy using wind turbines because of its overwhelming merits such as sustainability <sup>16</sup>, cost-effectiveness <sup>17</sup>, and clean energy <sup>18</sup>. Moreover, tidal energy projects were reviewed to optimize electricity production because of their low maintenance cost <sup>19, 20</sup>, renewable behaviour <sup>21, 22</sup>, zero  $CO_2$  emission <sup>23</sup>. In need of renewable energy, energy experts and researchers have been exploring the cost-effective and environmentally friendly solar and wind energy systems based on geographical locations for the generation of green  $H_2$  energy <sup>24, 25</sup>. Renewable  $H_2$  energy is zero-carbon fuel and can be utilized in fuel cells, internal combustion engines and power generation.  $H_2$  is booming and can contain major energy supply businesses around the globe <sup>26</sup>. The research and development community (R&DC) has realised that transformation of energy from fossil fuels economy to hydrogen economy is inevitable because  $H_2$  does not generate GHGE after burning <sup>27</sup>. The need of  $H_2$  is considerably increasing and multiplied three times since 1975, and it will keep increasing. Around 98% of  $H_2$  is produced from the fossil fuels sources, including natural gas (6%) and coal (2%) <sup>28</sup>. Nevertheless, generation of  $H_2$  from the fossil fuels is causing 830 million tonnes of  $CO_2$  emission per year (sum of total  $CO_2$  emissions of Indonesia and the UK) <sup>29</sup>. Figure 1 summarises the sustainable carbon free hydrogen energy system which enable and combine all the phases including renewable energy source, renewable hydrogen generation, hydrogen storage and hydrogen supply.

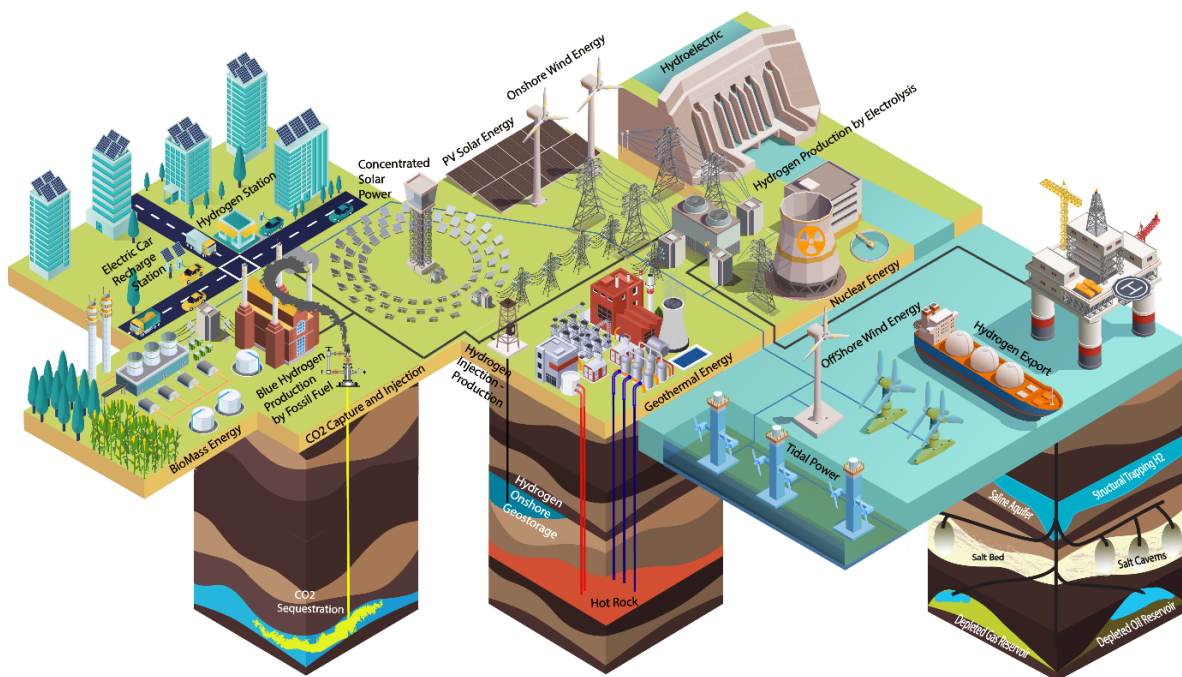


Figure 1 Graphical representation of entire carbon-free and sustainable hydrogen energy production and supply chain mainly comprising  $H_2$  geostorage in depleted gas reservoirs and salt caverns

Scientific community has made significant progress to generate  $H_2$  using electrolysis reaction using nanocomposite rods<sup>30, 31</sup>. The electrocatalysis reaction requires energy thus supply of energy from solar parks and windmills can be used to produce 'green  $H_2$ '. For example., 9.1 ton of water produced 1.1 ton of  $H_2$ , and 8 ton of  $O_2$  without  $CO_2$  emission using 39.4 MWh solar energy<sup>32</sup>.  $H_2$  can be used for passenger cars, prime movers, and buses, nevertheless a flexible, cost-effective and environmental friendliness storage system is needed so that  $H_2$  can be stored and reproduced adequately to compensate for fluctuating energy demand<sup>33</sup> without impacting the atmosphere. Energy yield of  $H_2$  is higher (e.g.,  $120 \text{ MJ}\cdot\text{kg}^{-1}$  energy density)<sup>34</sup> than  $CH_4$  ( $45 \text{ MJ}\cdot\text{kg}^{-1}$ )<sup>34</sup>. However, surface storage of  $H_2$  is a challenge<sup>35, 36</sup> because of the low volumetric density of  $H_2$  which is  $0.0838 \text{ kg}\cdot\text{m}^{-3}$  at ambient pressure and  $20^\circ\text{C}$ . Additionally, liquid  $H_2$  with  $70.8 \text{ kg}\cdot\text{m}^{-3}$  is not an adequate choice for long-term storage. Liquid  $H_2$  can continuously be boiled-off resulting inefficient energy storage system and may rise  $H_2$  leakage and  $H_2$  loss problems<sup>37</sup>.

Underground  $H_2$  storage could preclude multiple technical issues that constraint its widespread use<sup>38</sup>. For example., residual oil in the depleted reservoirs may influence  $H_2$

purity. Moreover, microorganism can consume  $H_2$  which may result in loss of stored  $H_2$  and precipitation in the pore-system due to release of by-products, including  $H_2S$  and the acids<sup>39</sup>,<sup>40</sup> Additionally, deep saline aquifer  $H_2$  storage system can cause the problems of mineral dissolution and high water cut during the withdrawing period of  $H_2$ <sup>41</sup>. Thus, **different mechanisms of formation damages can occur due to fines mobilisation and migration during hydrogen injection/withdrawal**<sup>42-44</sup>. Nevertheless,  $H_2$  storage in salt caverns is a proven technology<sup>45</sup>, owing to its inexpensive investment<sup>46</sup>, enhanced sealing properties<sup>47</sup> and minimum gas cushion requirements<sup>48</sup>. However, microorganisms in particular sulphate reducing bacteria (SRB) can develop the risk of  $H_2S$  release as a by-product in the salt caverns<sup>49</sup>. Moreover,  $H_2S$  release and dispersive behaviour of  $H_2$  may catalyse the  $H_2$  embrittlement in casing and well completion assembly, which result in  $H_2$  leakage<sup>50-52</sup>.

Biogeochemical, physiochemical, hydrodynamics and microbial activities can influence the underground  $H_2$  storage<sup>53</sup>. Effect of  $H_2$  storage in the sandstone rock was found inert with minimum mineral dissolution equilibria at the variable reservoir temperature conditions. Nevertheless, literature rarely reported the hydrogeochemical effect of  $H_2$  on shale (mica) and carbonate (calcite). Meanwhile, biotic transformation due to microbial activity can influence the gas mixing and propagation of microbial communities in the subsurface formation<sup>53</sup>. Importantly, SRB have a significant effect on  $H_2$  storage in the porous media as well as in salt caverns. SRB may consume  $H_2$  gas in their metabolic system and yield gases (e.g.,  $CH_4$ ,  $CO_2$ ,  $H_2S$ ).

Methanogenesis, homoacetogenesis and sulphate reduction are three major processes which lead to  $H_2$  consumption. Among 42 water test samples (depleted gas fields), 32 samples depict microbial activity at >122 °C temperature, and >4.4 M NaCl salinity<sup>54</sup>. Thus, it was recommended that monitoring of geochemical and microbial activities are essential for the sustainability of  $H_2$  underground storage<sup>39</sup>. In the context of storage security and withdrawing capacity,  $H_2$  has a low density, low viscosity and high diffusivity when compared to  $CO_2$  and  $CH_4$ . Thus, these fundamental and thermophysical behavior of  $H_2$  may cause loss of  $H_2$ , and critically impact  $H_2$  withdrawal capacity. But, this could be prevented by cautiously planning the injection and withdrawal scenarios in the porous media<sup>37</sup>. Additionally, high bouncy column pressure of  $H_2$  may have a considerable impact on geo-structural trapping<sup>55</sup>. Therefore, investigators believed that  $H_2$  can be safely stored at initial reservoir conditions in



both offshore and onshore depleted gas fields. In depleted gas fields, caprocks could provide sufficient sealing corresponding to high interfacial tension between water+ $H_2$  and capillary entrance pressures <sup>37</sup>.

Figure 2 summarizes the effect of geological formations, and microorganisms on the UGHS in the different mediums, including salt caverns, saline aquifers, and depleted gas reservoirs. Herein, we have discussed both porous reservoir rock (depleted oil/gas, and aquifers) and cavity reservoir rock (salt cavern) and quantified adequate liabilities for  $H_2$  biogeochemical storage security <sup>56</sup>. To achieve that: (i)  $H_2$  phase behavior, abiotic and biotic geological transformations have been provided which is very limited in the literature. (ii) Application, principles and energy conversion and management of green  $H_2$  have been discussed. (iii) Comparative analysis of depleted oil, depleted gas, saline aquifer reservoirs and salt cavern have been provided relative to storing characteristics, withdrawing capacity, underground microbial life and realistic experience. (iv) Occurrence of possible geological trapping and mechanism have been critically presented. (v) Salt cavern and its  $H_2$  storage capacity, operational challenges, possible solutions and recommendations are comprehensively evaluated and concluded.

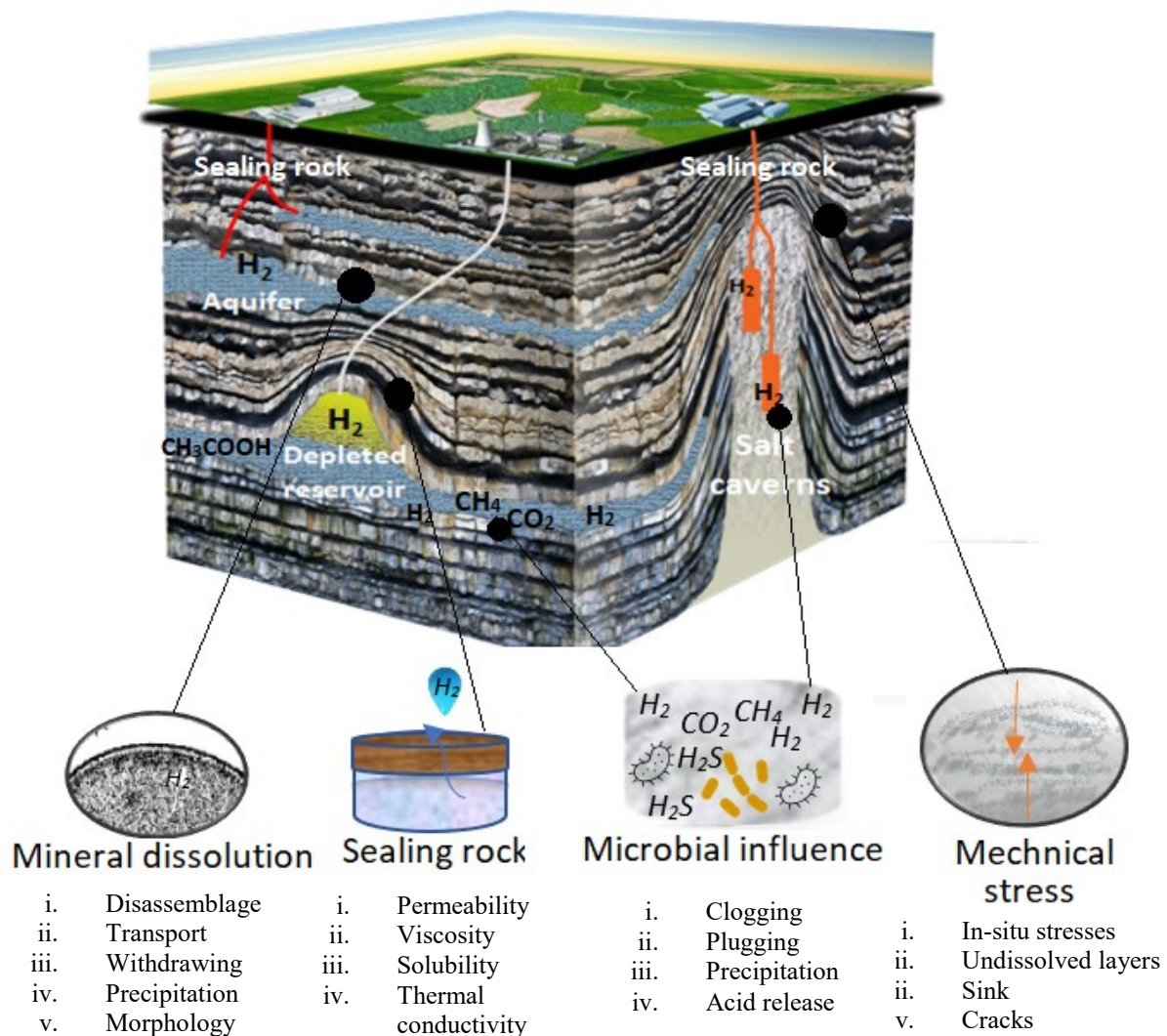


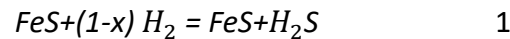
Figure 2 UGHS can be influenced by several factors, e.g., mineralogical alteration, sealing rock ability, microbial influence (natural, indigenous, and anthropogenic) and mechanical stresses

## 2 Abiotic and biotic transformation of the geological rocks

The geological rocks may be influenced by abiotic (e.g., mineralogy, temperature, pressure, salinity, and gas composition etc)<sup>57-76</sup> and biotic (both indigenous and anthropogenic microbial life) transformations in the presence of  $H_2$ <sup>39, 54, 77</sup>. The porous formation has a significant capacity to store  $H_2$  gas<sup>78</sup>. However, the interactions of  $H_2$  with rock-forming mineral (units) mainly quartz, calcite, and mica are rarely discussed in the literature, which can unveil important information regarding  $H_2$  underground storage security at large green-

scale (LGS) in depleted reservoir <sup>79, 80</sup>.  $H_2$  associated geochemical alterations were not observed in sandstone at variable injection pressure (1 to 20 MPa), reservoir temperature (20 to 100 °C) and salinity (0 to 10 weight%) <sup>81</sup>.  $H_2$  gas has a very small molecular size <sup>82</sup>, is less dense (less dense than air) <sup>83</sup> and has a strong diffusion rate<sup>84</sup> to such an extent that hydrogen can travel between the structure of clathrate hydrates <sup>85</sup>. It can easily spread in the formation cracks or natural fractures and migrate up to impact trapping structures <sup>49</sup>. In fact,  $H_2$  can react and form compounds.  $H_2$  exists in two distinctive oxidation states (+1, -1) thus it can act as oxidising and reducing agents <sup>86</sup>.  $H_2$  can induce redox reaction and alter mineral assemblage of rock resulting in mineral dissolution and precipitation <sup>53</sup>. Certainly, the petrophysical properties (e.g., porosity and permeability) can be influenced by mineralogical transformations and affect  $H_2$  production/injection cycle security.

For instance, sulphur species can be easily reduced by  $H_2$  at a very low oxidation state <sup>87</sup>. Therefore, pyrite (commonly found in the veins of quartz and sedimentary rocks) becomes thermodynamically unstable in the presence of  $H_2$ . Thus, pyrite reduces to pyrrhotite and  $H_2S$  as depicted in equation 1 <sup>88</sup>;






To further explore the phenomenon, researchers evaluated that pyrrhotite covered the pyrite particles when the temperature increased from 90 °C to 190 °C in the presence of  $H_2$  at 116 psi partial pressure of  $H_2$ . Thus, reduction in pyrite caused sulphide and precipitation in the system and impairment of rock's flowing properties. Importantly, the amount of sulphide has further reduced the pH of the solution which contains  $HS^-$ ,  $H_2S_{(aq)}$ ,  $H_2S_{(g)}$  <sup>87</sup> and can cause mineral dissolution. Researchers carried out numerical analysis and experimental studies to obtain geochemical reactivity of  $H_2$  with sandstone which typically contains quartz, K-feldspars, and other rock-forming units.  $H_2$  could not bring any mineralogical variation in the quartz nevertheless very minor alteration was obtained in hematite, and muscovite proportions <sup>89</sup>. However, iron was released from the muscovite that did not impact the permeability and porosity of the rock. Thus, sandstone was referred to as 'abiotic free mineral' and illustrated no transformation during  $H_2$  storage <sup>89</sup>. However, the effect of  $H_2$  is yet to be explored on hydrogeochemical alteration of calcite and mica. Moreover, biotic

mineral transformations have been noticed in several studies for  $H_2$  storage in the subsurface  
39, 54, 77.

Subsurface formation holds diverse types of archaea and bacteria, here collectively mentioned as microbes<sup>39</sup>. The potential microbial presence was observed  $1-17 \times 10^7$  cells ml<sup>-1</sup> in formation water samples, which can consume <0.01 to 3.2% of  $H_2$ <sup>90</sup>. The increasing concentration of injected  $H_2$  in the subsurface may trigger the microbe's growth<sup>77</sup>. Additionally, pH of formation water and brine may influence microbial growth through metabolism system and redox reaction. Methanogens, homoacetogens, and sulphate reducers are habited to 6.5 to 7.5 pH. However, the growth of most methanogens and sulphate reducers were not found at 4 to 9.5 pH<sup>54, 91</sup>. Biotic mineral transformation can adversely affect gas withdrawing, gas injection, formation permeability reduction and  $H_2$  loss<sup>77</sup>. SRB, methanogens and IRB can consume inorganic kosmotropic components include *NaCl*, *KCl* and sulphate sources (e.g., *Na<sub>2</sub>SO<sub>4</sub>*, *FeSO<sub>4</sub>*, *K<sub>2</sub>SO<sub>4</sub>*, *S*) in the presence of stored  $H_2$  and metabolically release by-products (e.g.,  $H_2S$ , acids,  $CH_4$ , and  $CO_2$ ) and ensured acidic behaviour<sup>92</sup>. SRB has induced carbonate precipitation and influenced the contamination security<sup>93</sup>. Most SRB including halophilic are permissive to growth and could induce stress in the presence of  $O_2$  and high salinity. Additionally, SRB consumes sulphate (as an electron acceptor) in the presence of  $H_2$  (as an electron donor). Additionally,  $H_2$  energy-based microorganisms lead by methanogens archaea<sup>94</sup>. Methanogens consumed  $CO_2$  and  $H_2$  in the presence of inorganic minerals components e.g., nitrite, sulphate and iron oxide and metabolically released  $CH_4$  and water<sup>95</sup>. Additionally, homoacetogens coupled  $H_2$  oxidation to  $CO_2$  reduction resulting acetate acid<sup>96</sup>, which can cause corrosion problems<sup>97</sup>. Additionally, variation in gas composition, clogging near injection wellbore, and biofilm growth have been observed nevertheless growth of microbes and their influence on the petrophysical property are not reported<sup>97, 98</sup>. However, chaotropy agents (e.g., *MgCl<sub>2</sub>*, *FeCl<sub>3</sub>*, *CaCl<sub>3</sub>*, *LiCl*, and *LiBr*) have ability to limit microbial life in the depleted oil/gas reservoirs, saline aquifers, and salt caverns for  $H_2$  storage projects. Table 1 presents the influence of microorganism reactions over  $H_2$  storage security in equations 2 to 5.

243 Table 1 Biotic transformation and impacts for  $H_2$  geostorage

Hydrogenotrophic microbes	Reaction and possible mineralization	Impact	Study
SRB (Bacteria) 	$SO_4^{2-} + 4H_2 + 2H^+ \rightleftharpoons H_2S + 4H_2O$ 3  $H_2$ reacts with anhydrite and other inorganic sulphate sources and reduces sulphate to sulphide.	<ul style="list-style-type: none"> <li>• <math>H_2S</math> release</li> <li>• High sulphide release</li> <li>• Gas mixing</li> <li>• Iron corrosion</li> <li>• pH reduction</li> <li>• Hydrogen embrittlement</li> <li>• Mineral precipitation</li> </ul>	99-107
Iron reducing bacteria (Bacteria) 	$3Fe_2O_3 + 5H_2 \rightleftharpoons 2Fe_3O_4 + H_2O$ 4  Microbes can reduce passive film, e.g., ferric components on metal surfaces.  By-product water can release and occupy interstitial pore space of sandstone causing excess water saturation and mineral dissolution	<ul style="list-style-type: none"> <li>• Low sulphide reduction</li> <li>• Metal corrosion</li> <li>• Carbon steel corrosion</li> <li>• Mineral dissolution</li> </ul>	108, 109
Methanogens (Archaea) 	$CO_2 + 4H_2 \rightleftharpoons CH_4 + 2H_2O$ 5  In an exceptional case, microbes attach to the edges of kaolinite clay and prevent $CH_4$ flow. Aluminium ions from kaolinite can be toxic to methanogens growth.	<ul style="list-style-type: none"> <li>• <math>CH_4</math> flow suppresses in Kaolinite</li> <li>• Injection reduces</li> <li>• Gas mixing</li> <li>• Withdrawing and injection capacity reduces</li> <li>• Permeability and porosity can alter</li> </ul>	110-112

244

245 Overall,  $H_2S$  increased the acidic behaviour in the porous media and causing mineral  
 246 precipitation <sup>113</sup>, and formation clogging <sup>114</sup>.  $H_2$  reinjection would be challenging, if the rate  
 247 of mineral precipitation is higher than the rate of mineral dissolution in the subsurface <sup>53</sup>.

Literature hardly provides information regarding biogeochemical behavior of microbes with rock-forming minerals (e.g., mica, and calcite) in the presence of  $H_2$  under reservoir conditions<sup>39, 53, 55</sup>.

### 3 Review of $H_2$ geological storage in depleted oil/gas, and saline aquifer

$H_2$  storage in the depleted oil systems seems to be adequate because there is already availability of natural space to be filled<sup>115</sup>. Moreover, the location of cap rock is already identified during seismic survey with reliable structural and sealing depth information<sup>116</sup>. The geological and mineralogical data of depleted oil and gas reservoirs are already known from well-logging and drilled cuttings<sup>117</sup>. Furthermore, a great deal of information relative to behaviour depleted oil reservoirs could be available to plan and design the feasibility of  $H_2$  storage<sup>118</sup>. Additionally, it has been evaluated that one giant depleted gas field can restrain sufficient seasonal  $H_2$  storage capacity for most of the countries around the globe. For example., North Sea Lemen field in the UK has 833 TWh storage capacity which is sufficient to fulfil the entire seasonal energy demand<sup>37</sup>.

Nevertheless, in depleted oil and natural gas reservoirs, a slow seasonal process can be achieved and therefore continuous turnover is difficult because of multiphase flow in the porous media<sup>39</sup> and overall performance of flexibility of  $H_2$  storage and withdrawal capacity are slightly fair in the depleted oil which present different types of reservoirs including saline aquifer, and depleted oil/gas reservoirs.

Additionally, evaporation of formation water in residual oil resulting contaminants which can reduce injectivity of gas besides the depleted oil field is seemed to be previously habituated with gas storage mechanism<sup>119</sup>. Additionally, evaporation of liquid media can increase the gas moisture content which can influence gas dehydration process cost at the surface. Moreover, humid shaly sand or reservoir rocks with high montmorillonite content may activate the process of the in-situ stresses and at a certain stage, it might have degraded formation potential to withdraw the gas<sup>120</sup>.

Therefore, there is a pressing need to properly analyse the feasibility of  $H_2$  in the depleted hydrocarbon reservoir because hydrogen can:

- Regarding biotic transformation: Microbes can consume carbon energy from residual hydrocarbon<sup>121</sup> and speed up their growth process in the presence of  $H_2$ . Moreover, sulphate is found in a considerable quantity in depleted oil/gas fluid wells. Thus,  $H_2$  injection may reuse sulphate because of increased microbial growth<sup>122</sup>.

- Regarding abiotic transformation:  $H_2$  may dissolve reservoir rock-forming units at high water saturation.  $H_2$  may react with sulphur-based minerals and produce abiotic  $H_2S$ , the process can deplete  $H_2$  purity and may catalyse the kinetics of gas mixing<sup>123</sup>. However, it is difficult to comment either biotic or abiotic is a major source of by-product gases and  $H_2$ /by-product gas mixing<sup>39</sup>.

However,  $H_2$  storage in the depleted natural gas reservoirs is advantageous when compared to its storage in saline deep aquifers because depleted gas fields have residual gas saturation. Therefore, a lower volume of injected  $H_2$  may achieve residual status in the depleted natural gas reservoirs<sup>124</sup>. Moreover, cushion gas requirement would be less in the depleted gas reservoir due to residual gas saturation. In the case of saline aquifer, since pore-spaces of aquifers are not filled with gas therefore initially it is necessary to fill the pore-space of aquifer<sup>125</sup>, which increases the cushion gas requirements. Aquifers have been used in Europe for natural gas storage. Aquifers are permeable porous geological rock formations that contain fresh water and sometimes a high concentration of brine water<sup>126</sup>. The permeable and porous formations of aquifers are mostly sandstone and carbonate<sup>127</sup>. The impermeable cap rocks (such as anhydrite layer, tight shale and salt) of aquifers are pivotal in ensuring the gas trap and storage process<sup>128</sup>.

In principle, rigorous exploration work is carried out to determine storing and sealing capacity of gas in aquifer reservoirs<sup>129</sup>. Several storage wells are required to be drilled through the caprock into aquifer reservoirs. Aquifer well is drilled in multiple phases and account for both cementing and casing cost<sup>130, 131</sup>. The aquifer rock contains brine or water which displace in the pore system by pumping  $H_2$ <sup>132</sup>. Thus, pressure can rise significantly due to compression in closed system aquifers thereby injection volume of gas in comparison to the formation

breakdown pressure limit is small<sup>80</sup>. Ultimately both factors, such as an increase in pressure and permeability of aquifer<sup>133</sup> can be used to measure the maximum  $H_2$  injection rates<sup>132</sup>.

Aquifers have the ability to store a large volume of gas<sup>134</sup> but there are some issues such as chemical and biological activities (such as *biofilms* caused by anthropogenic activities) in the vicinity of wellbore<sup>135, 136</sup>. It is possible that during the reproducing/withdrawing period, high bottom hole flowing pressure ( $p_{wf}$ ) (due to over volume of cushion gas) can push the  $H_2$  gas back towards the wellbore and extend injection/pumping time<sup>137</sup>.

The exploration cost of aquifer formation is high which is aimed to verify the size of the storage media and relative areal extent and structural trapping<sup>138, 139</sup>. Moreover, aquifer reservoirs are continuously examined using monitoring wells and storage wells<sup>140, 141</sup>. Additionally, aquifer reservoirs require a large volume of cushion gas during the phase of commissioning which is unreproducible during the phase of operation and decommissioning. Therefore,  $CO_2$  can be used as a cushion gas in aquifer reservoirs. Through this approach, a loss of injected gas can be mitigated in the deep saline aquifers. In aquifers, there might be a chance of the mineralogical activity where evaporated water encourages the generation of  $H_2S$  due to the presence of sulphide minerals and  $H_2$  which may reduce the hydrogen purity (via abiotic process)<sup>142</sup>. The feasibility of the  $H_2$  geo-storage in the depleted oil and gas reservoir and deep saline aquifers is given in the supplementary information in **Table S1**.

Overall, volumetric capacity, recovery efficiencies and rates of depleted reservoirs are not evaluated adequately and required in-depth investigation to formulate  $H_2$  injection program<sup>37</sup>. Accurate evaluation of these factors is possible with history matching of numerical modelling and operational data during field-scale  $H_2$  geostorage projects<sup>143</sup>.

### 3.1 Underground $H_2$ geo-structural trapping

Developing large-scale  $H_2$  storage in geological formations is required essential information of cushion gas requirement, storage capacity and sealing security. The overlying cap rock (e.g., shale) characterizes adequate permeability to mitigate  $H_2$  leakage in the complex media (gas/liquid/rock).



As aqueous phase (water, and organic traces) and non-aqueous ( $H_2$ ,  $CO_2$ ,  $H_2S$  and  $CH_4$ ) may basically act like hydrophilic and hydrophobic to the rock's surface and interstitial pore-network<sup>144</sup>. The wettability alteration is influenced by the flow of the different phases, surface morphology of rock, relative permeability, different phases saturation and capillary pressure<sup>145</sup>. Therefore,  $H_2$  trapping mechanism may possibly be affected via withdrawing, re/injection, formation contamination (fines migration), bacterial based formation precipitation and clogging, and mineral dissolution in pore-network system<sup>146, 147</sup>.  $H_2$  is high diffusive gas and therefore the main risk associated with its storage is leakage via underground natural pathways (such as., seepages, faults, and fractures) and drilled wellbores.  $H_2$  has a small molecular diameter<sup>148</sup> (when compared to  $CO_2$ )<sup>149</sup> and therefore, it may quickly buoyant upward under certain reservoir conditions. Investigators believed that uplift migration of  $H_2$  can be mitigated through high capillary entrances and structural trapping processes<sup>37</sup>. To date, the literature lacks to provide convenient information on the  $H_2$  trapping in subsurface media through the processes and leaves several open research questions for the scientific community<sup>150</sup>.

- Importantly, structural trapping is a principle mechanism for underground natural and anthropogenic fluid storage (Figure 3). Nevertheless, the physical properties of  $H_2$  (e.g., high diffusivity, light weight, and low solubility etc.,) and chemical kinetics (oxidation and reduction) may result in  $H_2$  leakage from fault paths. Moreover, information of  $H_2$  reaction with impermeable strata (e.g., shale and mica) is anonymous to date except for  $H_2$  reaction with Kaolinite and Smectite. These clays may mitigate  $H_2$  flow in the narrow pore-network of cap rock (e.g., shale) and ensure molecular  $H_2$  structural trapping<sup>103</sup>.

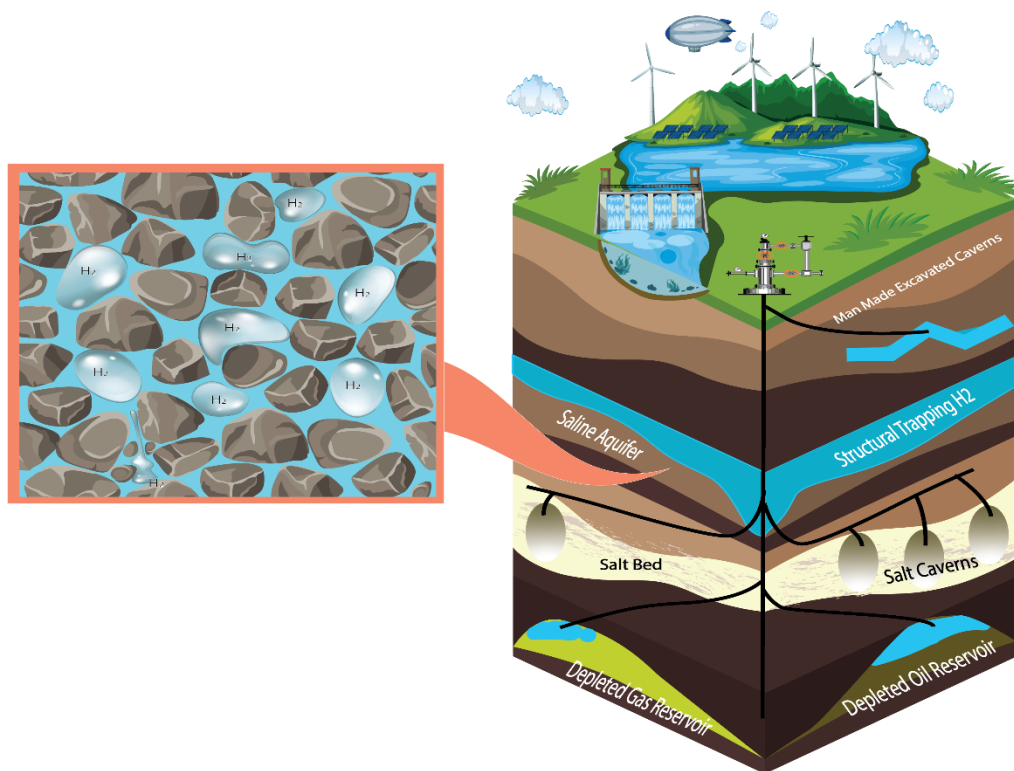


Figure 3 Structural trapping, capillary trapping, and mineral trapping have been illustrated in aquifer storage rock system (right).  $H_2$  molecule tends to migrate upward to achieve residual trapping and structural trapping (left)

358

359  $H_2$  gas bubble may trap in the pore system due to the influence of capillary forces and grain's  
 360 morphology resulting in an impact on residual trapping <sup>151</sup>. In our earlier study, we modelled  
 361 the interfacial tension of  $H_2$  and  $CH_4$  at storage conditions where higher capillary entry  
 362 pressure is predicted for  $H_2$  <sup>37</sup>. Moreover, morphology and size of pores in the rock can  
 363 influence the phenomenon. In typical water-saturated porous formation, interfacial tension  
 364 and density behaviour of  $H_2$  are different when compared to  $H_2+CH_4$  ( $H_2$ +cushion gas) which  
 365 is discussed in our present study as illustrated in Figure 4a. Interfacial tension of  $H_2$  is higher  
 366 when compared to  $H_2+CH_4$  which will increase the column height (e.g., capillary entry  
 367 pressure) and thus water-saturated caprock would be able to sufficiently seal the stored  $H_2$   
 368 (Figure 4a). Accordingly, hydrogen could be stored at a higher pressure than initial pre-  
 369 production pressures in depleted gas fields <sup>37</sup>. However, it is important to maintain stored  
 370 pressure lower than pre-production pressure to reduce the chance of geomechanical failure.  
 371 Nevertheless,  $H_2$  has less viscosity and density when compared to  $CH_4$  and  $CO_2$  which can  
 372 cause  $H_2$  viscous fingering (Figure 4 b and c). Moreover, thermal conductivity of  $H_2$  is high in

geological locations. Synergetic effects of these fundamental properties may kinetically influence the presence of  $H_2$  in the porous media and influence the  $H_2$  storage security.

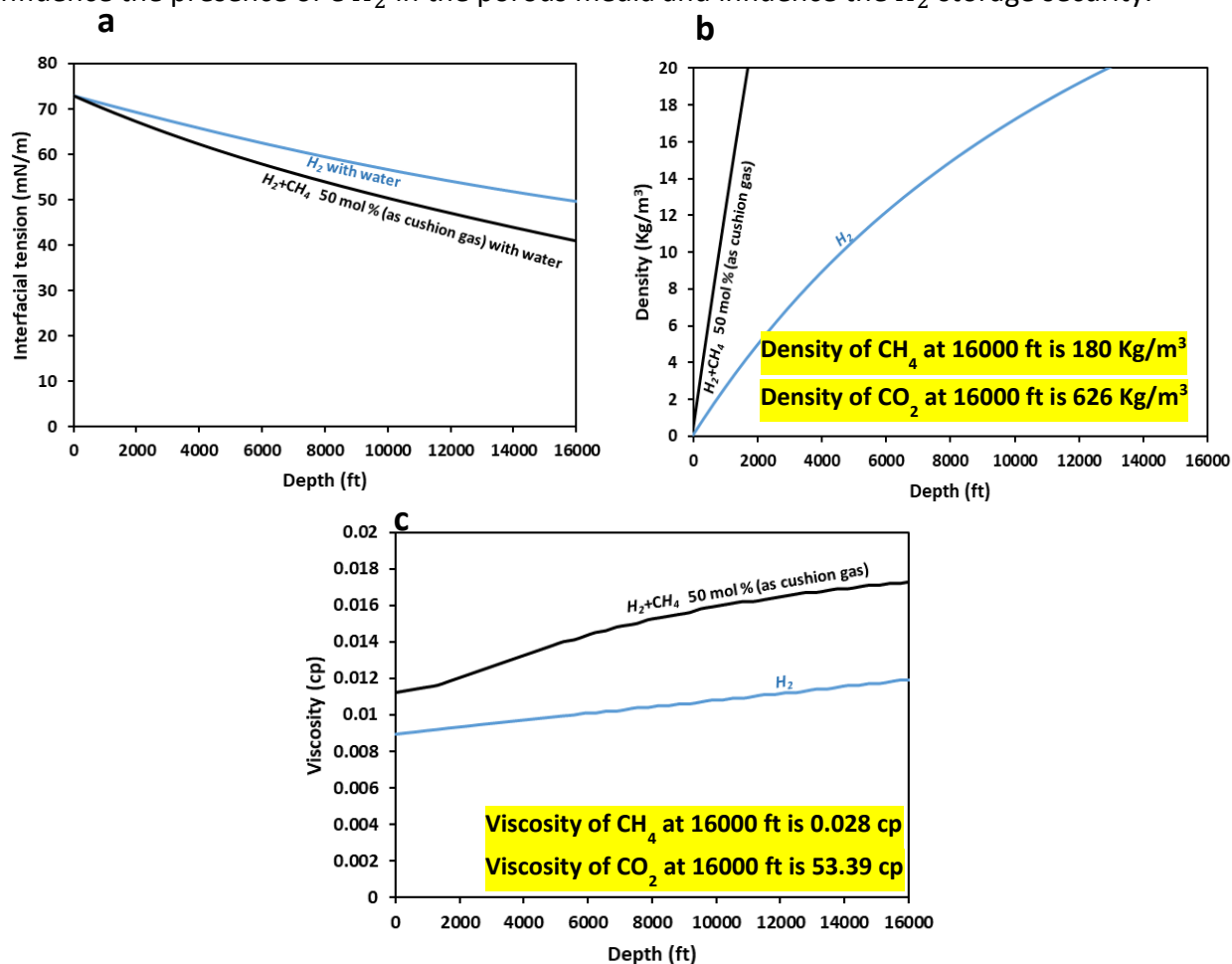


Figure 4 a)  $H_2$ , and  $H_2+CH_4$  (50mole%) interfacial tension along with water versus similar conditions b)  $H_2$ , and  $H_2+CH_4$  (50mole%) density versus depth, c) Viscosity of  $H_2$ , and  $H_2+CH_4$  (50 mole%) versus the depths. Equation of states and auxiliary models in the studies<sup>152-155</sup> were used to measure fundamental properties of the fluids and the techniques<sup>37, 156</sup> were used to measure the interfacial tension of the pristine gas and the mixed gas system.

$H_2$  is less soluble and lighter when compared to  $CH_4$  and  $CO_2$  thus it may achieve less solubility trapping. Solubility of  $H_2$ ,  $CO_2$  and  $CH_4$  in the water as illustrated in Figure 5a and b. Additionally, the adsorption process of gases (e.g.,  $CH_4$ ,  $N_2$  and  $CO_2$ ) in the pore-network system can increase with increase in the kinetic diameter of the gas molecule<sup>157</sup>. Assuming the same principle for  $H_2$ , the kinetic diameter of  $H_2$  is less than  $CO_2$  and  $CH_4$  thus  $H_2$  may achieve less adsorption in the pore-network system. Table S2 in the supplementary information provides the kinetic diameter of the gases and pore size of storage rock (e.g.,

sandstone and carbonate) and sealing rock (shale). The molecular size of gases is nano compared to reservoir rocks' pore sizes which are micro in size (excluding cap rock). Thus, gases can easily flow in pore-network with non-disruptive pore wall-gas molecule collision. Therefore, diffusion at molecular level is very likely and cause leakage in the micron size pore-network system<sup>158</sup>. In contrast, shale contains nano size pores (less than 2 nm) which may dominate collision between  $H_2$  molecules and pore wall to neglect molecular diffusivity and achieve structural trapping of  $H_2$ . Diffusion of  $H_2$  was determined in different gases system (e.g.,  $H_2$  in  $CH_4$  and  $H_2$  in  $CO_2$ ) using Chen and Othmer method and it was observed that  $H_2$  diffusivity was high when compared diffusivity of  $CO_2$  in  $CH_4$  (Figure 5c). Consequently,  $H_2$  may achieve uplift migration and tends to achieve cap rock trapping or structural trapping. Nevertheless, high diffusivity of  $H_2$  could raise leakage in low pressure zones and fault path leading  $H_2$  trapping insecurity.

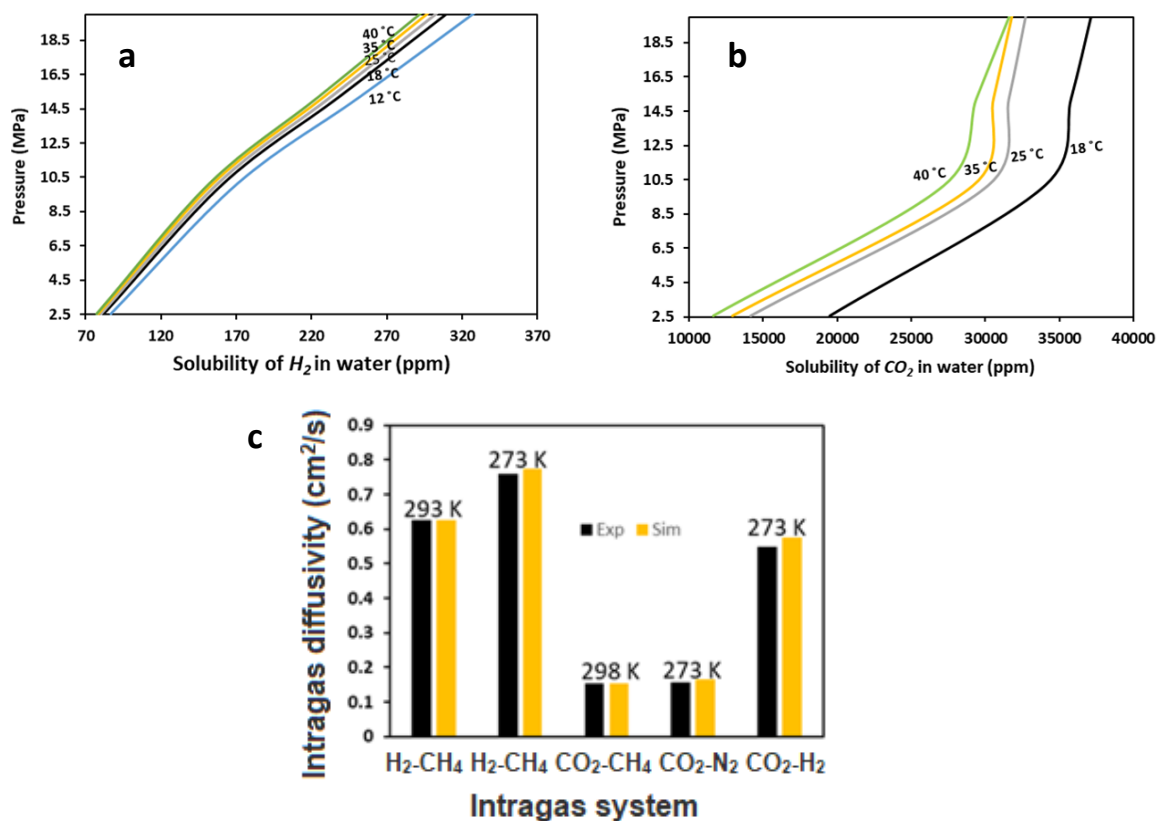


Figure 5 (a) Solubility of  $H_2$  in water at variable pressure and temperature was determined using Valderrama-Patel-Teja (VPT) equation of state used in the study <sup>159</sup> (b) Solubility of  $CO_2$  in water data at variable pressure and temperature was taken from the study <sup>160</sup>. Solubility of  $H_2$  is significantly less when compared to solubility of  $CO_2$  and  $CH_4$  in water. (c) Diffusivity of  $H_2$  in  $CO_2$  and  $CH_4$  and diffusivity of  $CO_2$  in  $CH_4$  are measured using Chen-Othmer technique <sup>161</sup> at variable pressures and temperatures

The trapping behaviour of sandstone (aquifer quartz surface) for  $H_2$  at realistic temperature and pressure conditions show that the rock surface was weakly/intermediate water-wet but after the addition of organic component onto the rock surface, the wettability of  $H_2$  was increased <sup>162</sup>. Nevertheless, organic components in the porous media may raise problems e.g., (i) organic components mixing with stored  $H_2$  and (ii) influence on the microbiological life (as microbes may consume organic components as an energy source) at pore-scale level and increase their activity <sup>39, 55</sup>. Moreover,  $H_2$  storage and structural trapping can be influenced by the mineralogy of sealing rock and hysteresis effect <sup>55, 163</sup>. The careful analysis of hysteresis can help to adequately predict  $H_2$  injection (primary drainage),  $H_2$  gas production (secondary imbibition) and  $H_2$  re-injection (secondary drainage) <sup>163</sup>. The recent simulation study quantified the trapping behaviour of  $H_2$ /brine in sandstone formation via interpreting the hysteresis effect <sup>163</sup>. However, they observed that cyclic hydrogen storage in the underground formation resisted the hysteresis effect which has been previously used to examine the gas storage (in particular  $CO_2$ , and  $CH_4$ ) mechanism at continuum scale via capillary pressure and relative permeability information. These both properties are sensitive to contact angle in the  $H_2$  storage system. Additionally, high frequent production/reinjection cycles may cause pressure and temperature variations. These underground variations may weaken sealing capacity of cap rock, minimize fracture pressure result in in loss of cushion gas and working gas. Therefore, detailed study of the storage rock via pore network imaging (e.g., mineral precipitation), kinetic rates and sensitive analysis of the modified hysteresis effect can provide necessary information of  $H_2$  residual saturation after secondary imbibition <sup>163, 164</sup> which is essential for the process of  $H_2$  production from geological formation. Operational parameters and feasibility of  $H_2$  storage in different storage systems are given in **Error! Reference source not found..**

Table 2 Comparison of underground porous reservoir rocks for hydrogen storage

Parameters	Depleted gas reservoir	Depleted oil reservoir	Saline aquifer	Reference
$H_2$ storage experience	Medium	No	Medium	119, 132
Exploration cost	Medium	Medium	High	165
Hydrogen mixing with other components/ and loss	High	High	Low	166
Hydrogen withdrawing capacity	Low	Low	Low	33
Presence of microorganism	Low to high	Low to high	Medium	39
Storing media	Porous	Porous	Porous	138, 167
Bottom hole flowing temperature (°F)	150	150		
Bottom hole flowing pressure (psi)	150 to 500	250 to 500		168
Areal extent (sq.km)	Varies significantly	Varies significantly	Varies significantly	
Interval thickness (m)	25 to 50	25 to 50		169
Typical storage capacity (Gt)	675 to 9000		1000 to 10,000	
Salinity (ppm)	Varies	Varies	1500000 to 1900000	
pH	7	7		39
Water cut	30 to 70%	30 to 70%	80 to 90%	169

#### 4 Prospect of underground $H_2$ storage in salt formation

In comparison to  $H_2$  storage in the porous rock, its storage in salt cavern has been less challenging due to the reason that salt layers are impermeable and inert to  $H_2$ . Moreover, withdrawal capacity of  $H_2$  is more efficient in the salt cavern when compared to porous rock as could be used as huge storage tanks. Nevertheless, field-scale  $H_2$  storage in the salt cavern has several challenges. Gas storing capacity and salt stability in salt caverns are key factors for the consideration of  $H_2$  storage<sup>48, 170</sup>. Large pillars of thick salts layers of caverns (both top and bottom layers) presented efficient  $H_2$  storing capacity<sup>171</sup>. Realistic experience of salt cavern  $H_2$  storage found satisfactory relative to high cavern pressure potential and

homogeneity in the salt formation<sup>172</sup>. The large salt caverns are constructed in salt domes (with uniform layers of salt) near the Gulf Coast in the US<sup>173</sup>. However, the geology of salt caverns located in Western States, North-eastern, and Midwestern is not homogenous and as such inadequate for storing  $H_2$  in the US<sup>174</sup>. In US, Germany, and the UK,  $H_2$  salt cavern realistic storage projects provided four decades of experience. This experience can be utilized for the establishment of LGS  $H_2$  storage capacity<sup>175</sup>. The large volume of the cavern can provide a high flow rate of  $H_2$ . Capsule type salt cavern is considered more appropriate choice for  $H_2$  storage because of its better height and adequate stability (e.g., under low tensile and overburden stresses)<sup>176</sup>. The storing media has adequate stability to high pressure and low-temperature conditions<sup>33, 177</sup>. Moreover, smooth operational proceedings of the project are very pivotal for its successful completion<sup>178-180</sup>. Salt cavern  $H_2$  sealing capacity is high however mechanical and mineralogical properties of the salt cavern are important factors<sup>181</sup> to endure compressive and tensile failure. Moreover, low working pressure may reduce the risk of mechanical failure and sink risk, however, it would increase the expenses and later required high pressure  $H_2$  injection operation to maintain the in-situ pressure of the cavern for less injection time and optimum delivery of  $H_2$ <sup>124</sup>. However, salt cavern provided low storage capacity and did not provide long-term storage solution when compared to depleted oil and gas reservoirs. Operational parameters for underground hydrogen storage in salt cavern are provided in Table S3.

## 4.1 Salt cavern UGHS challenges and solutions

Selection of salt cavern for the  $H_2$  storage depends on the depth, purity, composition, and wall thickness of the salt cavern<sup>182</sup>. Continuation, distribution, and thickness of the rocks (evaporate type) varied within the basin area which is further based on the formation of the salt structures such as pillows, salt stocks and diapir. Investigators found that average salt structures can store around 214 kWh and 458 kWh per  $m^3$ <sup>49 183</sup>. Nevertheless, salt dome structures have more energy storage density such as 210 GWh when compared to a salt bedded structure which could provide around 65 to 160 GWh energy storage capacity<sup>183</sup>.

Salt beds and domes are naturally developed due to movement between the substrate and overlying strata in the presence of low-density salt; the mechanism is known as 'halokinesis'<sup>184</sup>. This mechanism could be influenced by buoyancy, gravity difference, salt spreading, thermal convection and differential loading forces<sup>185-187</sup>. Buoyancy forces and low-density salt layers are primary reasons for the formation of a salt dome in comparison to the effect of tectonic activity<sup>188</sup> as depicted in Figure 6Error! Reference source not found..

Typically, salt caverns are made up of halite salt along with anhydrite salt (layers). Both halite and anhydrite remain as the main sources of salt cavern's brine composition. Adequate salt diaper which is composed of 99% halite ( $NaCl$ ) and less than 1% of anhydrite ( $CaSO_4$ ) salt and other impurities<sup>189</sup>. However, the composition of salt bedded layers and salt domes are based on geographical locations and subsurface environment. The uniform layer of halite ( $NaCl$ ) could be an appropriate choice for the construction of salt caverns. Thanks to halite salt due to its high thermal conductivity, self-healing properties, impermeable behaviour and plastic properties, it could establish potential sealing to mitigate  $H_2$  leakage in the system<sup>190</sup>. Importantly, halite could not react with  $H_2$ . However, there were some common impurities such as quartz ( $SiO_2$ ), anhydrite ( $CaSO_4$ ), dolomite ( $CaMg(CO_3)_2$ ), pyrite ( $FeS_2$ ), gypsum ( $CaSO_4 \cdot 2H_2O$ ), and calcite ( $CaCO_3$ ) could be found in the salt layer which may react<sup>191</sup> but requires further investigations. Moreover, some common ions impurities are also observed e.g., as  $Fe^{+3}$ ,  $Mg^{+2}$ ,  $CO^{-2}$ ,  $Ca^{+2}$ ,  $SO_4^{-2}$ ,  $Fe^{+2}$ ,  $K^+$ , and  $Cl^-$ ,  $Ba^{+2}$ ,  $B^{+3}$  and  $Sr^{+2}$ <sup>49</sup> which can enhance microbial activity. Additionally, the mineralogical properties of anhydrite salt are required to be analysed because of its hygroscopic nature. Moreover, the interaction of anhydrite salt with water produces gypsum and the solubility of anhydrite is 140 times less when compared to halite salt e.g., 2.5 g of anhydrite salt requires a litre of water for its absolute solubility<sup>192</sup>,<sup>193</sup> which can cause an inappropriate delay in salt cavern construction. High concentrations of  $Ca^{+2}$ , and  $SO_4^{-2}$  ions from anhydrite remain in the cavern and it could form  $H_2S$  in the presence of  $H_2$  or methane through both biotic and abiotic sulphate reduction.  $H_2S$  has corrosive (can develop  $H_2$  embrittlement problems in casing and steel tubulars) and toxic nature which may increase surface processing facility which results in an increase in the overall cost of the project. Hence,  $H_2S$  catalyses the  $H^+$  ions embrittlement problems in steel tubular; it reduces the tensile and ductile strength of the tubular and de-velops the corrosion films of  $FeS$  and free  $H^+$  on the surface of metal. Thus, free ions of  $H^+$  along with  $S^{2-}$  accelerate the corrosive



rate via  $H_2$  or  $H^+$  ion trapping in the interstitial spaces of the metal promoting hydrogen embrittlement in the system <sup>194</sup>. Hence,  $H_2$  can cause the embrittlement problems and proceed the  $H^+$  diffusion and its adsorption in the interstitial spaces (metal lattices) <sup>195, 196</sup>. Cavern leakages problems are mainly associated with 'Fillings' (e.g., undissolved rock layers) in salt caverns, overburden compressive forces, tensile forces, microbial degradation activity, well casing leakages and  $H_2$  embrittlement (corrosion damage) <sup>197-199</sup>. Figure 6 provides a drawing of a salt cavern and its problems which can influence the UGHS process. Thus, self-healing (natural cavern's wall recovery) and tight permeability of salt cavern's wall (for  $H_2$  entrapment in pores) could be two pivotal factors for enhanced  $H_2$  gas storage and security. The permeability of 1 m thick salt layer is evaluated 2 nD at 1 MPa pore pressure value <sup>200</sup> nevertheless typical permeability of tight gas reservoir is 1000 nD <sup>201</sup>. However, in amateur salt structure, mechanism of 'halokinesis' and the contaminations in the salt formation can increase the permeability of salt cavern resulting  $H_2$  leakage and inadequate reinjection of  $H_2$  into salt cavern. Table S4 presents the review of salt cavern performance, challenges, and adequate solutions.

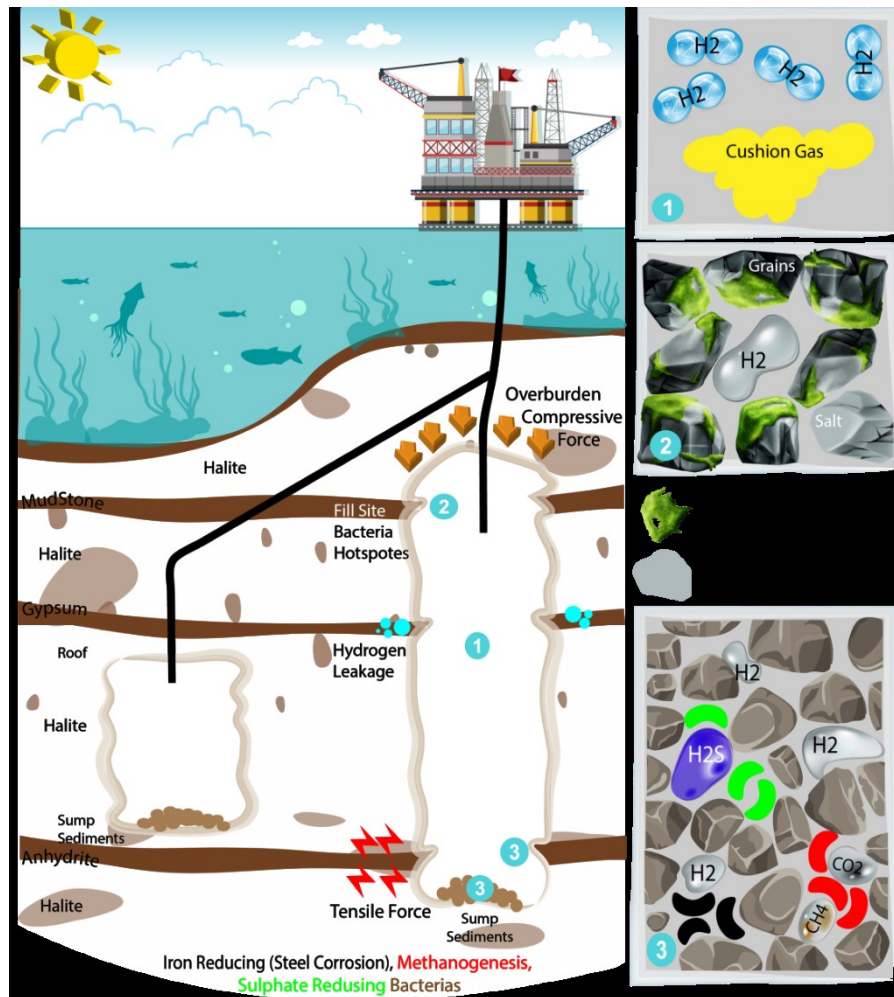


Figure 6 Salt caverns challenges have been illustrated at a microscopic level: 1) Cushion gas (e.g.,  $N_2$  and  $CO_2$ ) is recognised as inert gas. Nevertheless,  $H_2$  withdrawing cycles may ensure in-situ thermal variation and can impact  $H_2$  mixing with the inert gas <sup>132</sup>. 2). Salt has natural self-healing properties <sup>202</sup>. However, deposition of microbes on salt crystals and acids release from microbes can influence the self-healing behaviour of salt cavern. Consequently, the process may degrade rock salt stability, rise permeability, microcracks and creep damage <sup>190, 203</sup>. 3). Anthropogenic drilling fluid additives waste (e.g., polymers and carbonate sources) etc., may promote bacterium growth in the cavern's 'Fillings' and sump. Microorganism living in the fillings may consume anhydrite salt causing,  $H_2$  loss, permeability increment,  $H_2$  leaking and  $H_2S$  generation in the system <sup>166, 204</sup>. More importantly, fillings problem is common in bedded salt cavern system and may emerge undissolved rock layers e.g., anhydrite and mudstone as  $H_2$  leakage hot-spots.

506

507

508

509

510

## 4.2 Biogeochemical behaviour of $H_2$ in salt formation

Salt formation is inert and inactive to hydrogen<sup>205</sup>. However, brine water can stay in the salt cavern's sump. Brine water may evaporate into stored gas<sup>205</sup> and increase moisture content in the gas which can be a challenge and requires surface facilities for dehydration of  $H_2$ . Overall, the amount of contamination in the withdrawn  $H_2$  gas from salt cavern is less when compared to depleted oil and natural gas fields<sup>121</sup>. More importantly, the pore-network in the depleted reservoirs may be plugged due to reactions between minerals and  $H_2$  via microorganism (biotic) and host rock (abiotic)<sup>206</sup>. Thus, withdrawing and reinjection capacity of  $H_2$  may be influenced in depleted reservoirs. The practical experience shows that both natural gas and  $H_2$  were stored together in salt caverns successfully for several decades in the UK, the US and Germany<sup>79, 207</sup>. The inert nature of salt with hydrogen yields overall high stability, adequate flexibility, improved integrity, and enhanced withdrawing capacity. Therefore, it can be used to contain daily demand or seasonal gas peaks in winter for heating purposes. Moreover, salt cavern  $H_2$  storage is cost-effective, stable and operationally durable, contaminated free, and viable to store gases and liquids at high-pressure conditions<sup>208</sup>. However, the main problem is the storage capacity of salt caverns which is comparatively low.

Salt caverns are artificially developed by injecting water into salt formations to carry out salt dissolution which is referred to as 'salt mining'. The typical feature of a salt cavern is listed in Table 3. Artificially developed salt caverns have been used for 50 years, and primarily used for the storing purpose of hydrocarbon, in particular methane, and oil, later it has been noticed as a potential storing media for  $H_e$ , and  $H_2$ . First time in US, oil and LPG were both stored in salt caverns in 1950. In 1961, the very first salt cavern was used for the storing of natural gas in US<sup>209</sup>. Nevertheless, the first salt cavern for the storage of  $H_2$  was developed in the UK in 1971 and it is operational to date. Interestingly, around 300 and 2000 salt caverns are in Germany and North America currently used for the storage of compressed air, compressed  $H_e$ , butane, radioactive waste and compressed  $H_2$ <sup>208, 210</sup>.

**Table 3** Typical artificial salt cavern features for H<sub>2</sub> storage

Factor	Configuration	References
Volume	Storing volume 100000 m <sup>3</sup> , and vary with geographical based on the technical as well as geological history, geographical location and behaviour of the salt cavern	210, 211
Salt thickness	At least 200 m	210-212
Depth	At least 500 m to 2000 m	210, 212
Height	At least 400 m	210, 213
Operating pressure	20 MPa is essential for high volumetric storing capacity	210, 212
Mechanical properties	Optimum mechanical stability of salt cavity is key to sustainable H <sub>2</sub> storing	210-212

High diffusive behaviour of H<sub>2</sub> and the bacterial process can damage the sealing behaviour of the cavern and contaminate the stored H<sub>2</sub> purity<sup>49</sup>. Microorganisms are living in the sump's residual water with indigenous microorganisms communities since the leaching process. The sump may contain anthropogenic drilling material which may provide energy sources (e.g., cellulose, starch, SO<sub>4</sub> and insoluble carbonates) to bacteria<sup>203</sup>. Thus, bacteria can start consuming H<sub>2</sub> and generate H<sub>2</sub>S in the presence of carbonate and sulphate via sulphate reduction<sup>214</sup>. *Desulfovibrio halophilus* and *Desulfovibrio Vulgaris* utilized sulphate for the acceptance of electrons in the environment of anaerobic metabolism<sup>215, 216</sup>. Bacterial survival is based on sulphate reduction such as from sulphate (S[+VI]) to sulphide (S[-II]). Sulphate is activated before it can accept the electron via enzyme adenosine triphosphate sulfurylase phenomenon, and thus synergy behaviour of triphosphate sulfurylase+sulphate develops adenosine 5' phosphosulfate and reduced sulphate to sulphide ultimately produce H<sub>2</sub>S in the presence of H<sub>2</sub><sup>217</sup>. Table 4 illustrates that different types of SRB have the ability to survive typical reservoir temperature condition. In fact, the growth of these bacteria expedited at these temperatures and increased sulphate reduction process. Figure 7 depicts that SRB have been found in salt cavern, depleted hydrocarbon reservoir rocks and saline aquifer which can generate H<sub>2</sub>S in the system<sup>49, 218-225</sup>. Some storage rock has shown high H<sub>2</sub>S generation when compared to the allowable limit.

561      Table 4 Reaction and temperature in geological rock for the occurrence of the bacteria

Type of bacteria	Factors	References
Thermochemical sulphate reduction	100 to 180 °C	218
Bacterial sulphate reduction	0 to 60-80 °C Some greater than 80 °C	226
Hyperthermophilic SRB	110 °C	227
Optimal growth temperature for the SRB	38°C, acidic, saline environment. Mostly SRB activity reduces, if concentration of NaCl increases above 50 to 100 g/l, however, SRB activity is found in salt lakes and brine water which reflects sustainability of SRB in high salt concentration system.	218

562

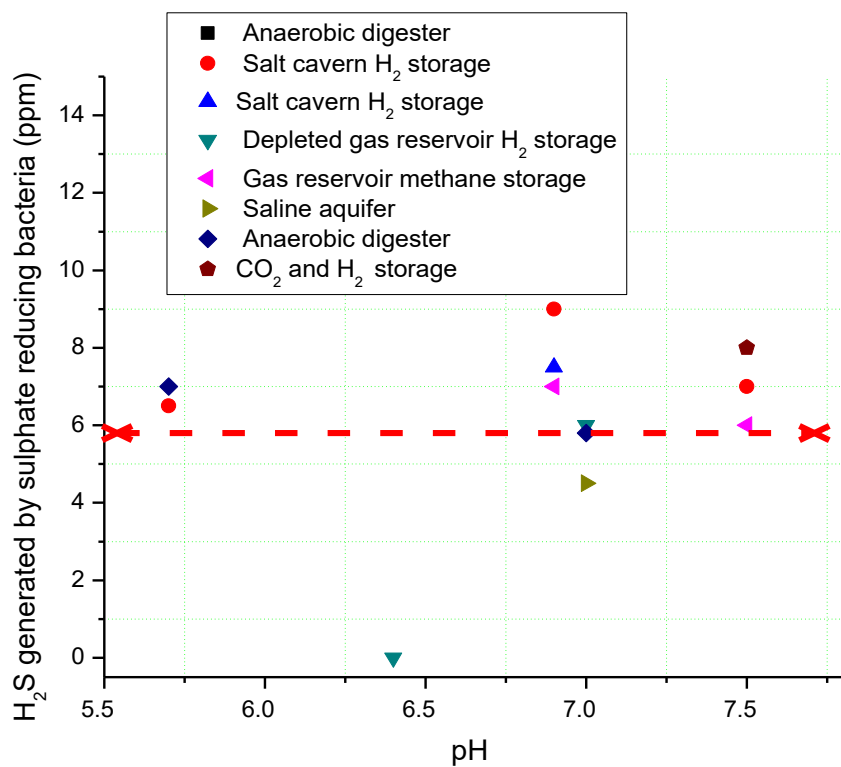


Figure 7 Sulphate reducing bacteria has generated  $H_2S$  in the surface and subsurface storage systems. Storage rock has shown high generation of  $H_2S$  which is greater than its threshold value (red dashed line) <sup>49, 218-225</sup>.

563

564

### 4.3 Progress, and factors influencing the development of salt cavern

Selections of fresh water, drilling fluids and completion fluids are important factors during the construction of a salt cavern. Underground salt formations are not sterile and contain multiple types of indigenous, natural, and anthropogenic microorganisms. The supplement source of energy from fresh water (such as carbonates ( $CO_3^{2-}$ ), and  $Mg^{+2}$ , and  $Ca^{+2}$  etc.,) and drilling fluids (e.g., barium sulphate ( $BaSO_4$ ), cellulose and starch polymers) may improve the growth of microbes inside the caverns and rise problems. Leaching, debrining, and filling are pivotal phases of underground salt cavern construction<sup>228, 229</sup> and carried out into geological salt deposits as illustrated Figure 8. The geological salt deposit, in particular, salt domes is selected after careful assessment of the previous exploratory and drilled wellbore data<sup>230</sup>. Time period for the development of salt cavern based on the areal extent of salt formation and formation hydraulic diffusivity, however, it might take more than one year to construct a single cavern<sup>177, 231</sup>. The drilled hole which could be used for the injection of  $H_2$  based on the factors, including geological formations, structure, fault locations and depth of the salt caverns (which typically range from 300 m to 2000 m). Like in oil and gas well drilling, the salt cavern wells are also drilled in a telescopic design, however, the diameter of salt cavern wells is larger when compared to conventional oil and gas wells<sup>232</sup>. These caverns are cased and cemented adequately so that  $H_2$  gas may not leak and sustain smooth  $H_2$  injection/production cycle<sup>233</sup>. Tightness of the salt cavern well is examined to predict cementing and casing leakages problems<sup>234</sup>. Then, brine is displaced towards the surface via injection of  $H_2$  inside the salt cavern during filling phase. Nevertheless, 100% brine recovery is not easy because production tubing did not reach until the bottom of salt cavern<sup>235</sup>.

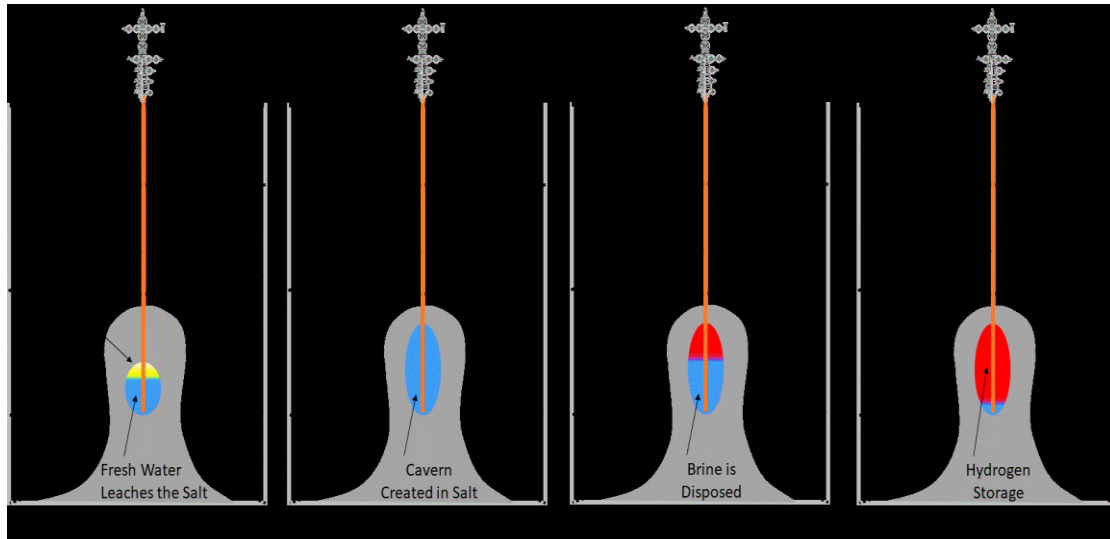


Figure 8 The process of salt cavern development involves multiple steps such as i Salt formation selection ii Leaching, iii Debrining phase and iv Filling

587

588 Design of salt cavern strongly based on the properties of the salt rock deposits and its  
 589 structure <sup>236</sup>. Additionally, other factors are also required to be given proper attention during  
 590 the formation of salt caverns e.g., depth of salt cavern <sup>182</sup>, height and diameter of salt cavern  
 591 <sup>237</sup>. For the geo mechanical stability of the cavern, the salt thickness of both hanging wall as  
 592 well as foot wall <sup>238, 239</sup> and relative information of the cavern must be explicitly defined. The  
 593 minimum safe thickness of the salt cavern is the function of the diameter of the salt cavern.  
 594 For instance, it has been suggested that the minimum thickness of the hanging wall must be  
 595 equal to 75% of the cavern's diameter; and 20% of the cavern's diameter for the case of foot  
 596 wall. Additionally, the least ratio (height to diameter) of the salt cavern must be 0.5 in the  
 597 condition of bedded salt structure <sup>240</sup>. The capsule-shaped salt caverns have been widely used  
 598 for the  $H_2$  storage purpose. The capsule-shaped cavern adopted minimum stress when  
 599 compared to a cylindrical or elliptical shaped cavern at 27 MPa overburden pressure and 1200  
 600 meter depth <sup>240</sup>.

601 In Utah US, researchers are working to store  $H_2$  underground in a vertical salt cylinder which  
 602 is 804 m wide and 1609 m deep. This could be the largest salt cavern reservoir to store  
 603 underground  $H_2$  in the history of the US. The project could produce around 1000 MW of clean  
 604 energy via stored  $H_2$ . The stored  $H_2$  would be enough power to provide electricity to 150,000  
 605 households for the period of one year. <sup>241</sup>.

In the first phase of the project,  $H_2$  energy storage would supply around 150,000 MWh of storing capacity which is 150 times higher energy when compared to the existing lithium-ion batteries storage system in the US <sup>241</sup>. Additionally, the cost of underground salt drilling and maintenance is 10 times less than surface  $H_2$  storage tanks system and it is 20 times less when compared to hard rock mines expenditures. According to the US Strategic Petroleum Reserves data, the US has around 60 caverns which are typically 200 ft diameter and 2500 ft tall. Table 5 presents the underground salt cavern  $H_2$  storage projects information.

Table 5 Operational  $H_2$  salt cavern projects

Countries	Salt cavern $H_2$ storage sites	Potential of salt caverns	References
The UK	Teesside (operational)	<ul style="list-style-type: none"> <li>• Elliptically shaped,</li> <li>• Depth of 350-450 m</li> <li>• Volumetric capacity of 210,000 m<sup>3</sup></li> </ul>	33, 205
The US	Operational Moss Bluff, Clemens salt dome, Spindle top	<ul style="list-style-type: none"> <li>• Depth of 800 m (cavern top)</li> <li>• Storing volumes 580,000 m<sup>3</sup> capacity</li> </ul>	33, 242
	Salt cavern $H_2$ stored facility in Texas since 1980s.	<ul style="list-style-type: none"> <li>• 850 m cavern's roof height,</li> <li>• 49 m diameter and 300m height</li> <li>• Storing capacity of 1066 million cubic feet (or <math>30.2 \times 10^6</math> m<sup>3</sup>)</li> </ul>	

Information relative to the volumetric capacity of the salt cavern is important to carry out a suitable  $H_2$  storing program <sup>243</sup>. The method for the measurement of volumetric capacity is defined in the previous study <sup>33</sup>. Typical cavern construction involved multiple steps such as in-depth geological investigation which illustrates information of salt domes, inter-bedded salt structures and their areal extent <sup>33</sup>. Basic parameters are pivotal to be considered e.g., cavern roof depth, storage pressure, gas cushion, water volume in the cavern, and surface pipeline facility. The cavern's thickness of 500 m to 2000 m and height of 500 m to 1200 m would be an appropriate choice for 7.09 MPa to 19.2 MPa storage pressures <sup>33</sup>. This could be explained that high thickness salt wall and roof are required which can sustain high injection pressure and microbial degradation activity in the system <sup>243</sup>.

Importantly, the cost of the cavern during gas injection remained consistent until unless the underground  $H_2$  storage pressure of the system is maintained. Hence, maximum underground pressure should be maintained  $P_{\max} > 7$  MPa. This may influence the cost of the compressor capacity and its power consumption. Moreover, the cost may raise with the depth



of the injection well bore and the use of high-grade tubular accessories (both casing and completion). Additionally, it is pivotal that cushion gas is controlled and made consistent around 30% of storing volume <sup>33</sup>. Additionally,  $H_2$  withdrawing pressure can be maintained adequately relative to cushion gas volume pressure <sup>244</sup>.

## **5 $H_2$ energy storage capacity in pipelines, gasometer tanks, depleted gas reservoir and salt caverns**

We found that a single Marlin offshore field in Australia could store more than 100 TWh energy storage capacity of  $H_2$  as illustrated in Figure 9a. This is enough energy to fulfil the demand of South Australia which annual demand was recorded 89.61 TWh in 2019 to 2020 <sup>245</sup>. Underground  $H_2$  trapping is safe, environmentally friendly and provide massive  $H_2$  energy storage solution when compared to surface  $H_2$  storage system. However, surface liquid  $H_2$  storage system may loss and boil off  $H_2$  due to heat transfer from the environment <sup>246</sup>. Thus, depleted gas reservoirs and salt caverns are apparently adequate choices for long-term and short-term  $H_2$  storage.

Salt cavern storage could help to compensate fluctuating energy demand (and sustain multiple cycles) <sup>55</sup>. Figure 9b summarises the energy storage capacity of  $H_2$  increases (and volume of the stored gas decreases) with increase in pressure and density which agrees with typical behaviour of the gases. Generally, the energy storage capacity of  $H_2$  can vary with the volumetric capacity of salt caverns (e.g., 750,000 m<sup>3</sup> 500,000 m<sup>3</sup>) as illustrated in Figure 9b. The graphical illustration shows that the energy storage capacity of  $H_2$  could increase with depth. However, a uniform structure with an adequate salt thickness could impact the withdrawing capacity of  $H_2$  which are geographically constrained.

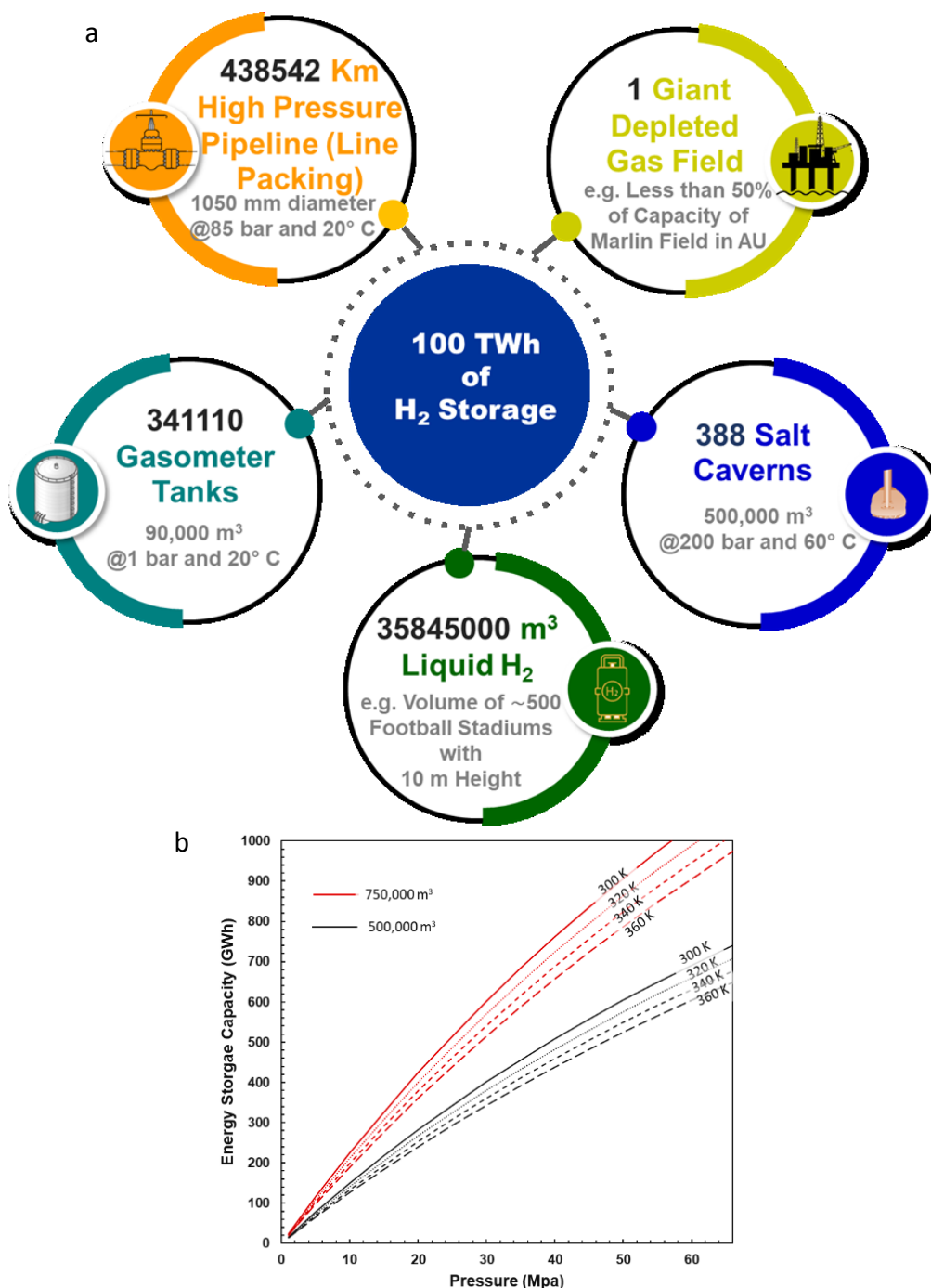


Figure 9 (a) Single Marline offshore depleted gas field could store 100 TWh of  $H_2$  energy which is equivalent to 388 salt caverns capacity (each 90,000 m<sup>3</sup>). Each surface facility including 34111 gasometer tanks (each 90,000 m<sup>3</sup>) and 438542 Km line packing (diameter 1050 mm) could store 100 TWh. (b) Energy storage capacity of salt caverns of different volumetric capacities decreases with temperature and increases with pressure. The storage capacities have been calculated using H2CapEs<sup>37</sup>

## 654 6 Conclusions

655

656 We have drawn the following conclusions from this review study:

- 657 i.  $H_2$  energy and its storage technology are pacing with unprecedented momentum.  
658 Thus, the prospect of  $H_2$  energy seems to be very bright due to its overwhelming  
659 advantages: clean source of energy, amazing energy density, and transformative  
660 nature.  $H_2$  can be produced through green techniques. It has the potential to be used  
661 in various practical applications with high energy performance facilitating social  
662 growth, economic competitiveness, and environmental benefits. More importantly,  
663 developed economies in particular Australia, Germany, the UK, the US have realised  
664 that there is a need to scale up  $H_2$  production and its flexible storage system at the  
665 LGS to deliver a future featuring “energy accessibility, security, affordability and  
666 sustainability”.
- 667 ii. Energy stakeholders have realised that  $H_2$  (as clean energy) has the potential to transit  
668 from fossil-based energy economy to  $H_2$  economy. Since the last decade, significant  
669 contributions have been made to produce  $H_2$  gas via environmental friendliness and  
670 cost-effective way. However, flexible  $H_2$  storage remains a challenge and requires  
671 extensive research at an industrial scale.
- 672 iii. Depleted natural gas and oil reservoirs are considered for  $H_2$  storage because of their  
673 benefits, such as these are seismically proven large extended areas. Moreover,  $H_2$   
674 storage operator will have enough former mineralogical and geological (drilling order  
675 data) to understand the appropriate physiochemical behaviour of  $H_2$  and their  
676 underground interactions with the grains and in-situ residual saturations.  
677 Nevertheless, if  $H_2$  is stored in the depleted natural gas fields, it can contaminate with  
678 residual natural gas, and thus when  $H_2$  will be withdrawn from the reservoir it can be  
679 used for heating purposes.  $H_2$  storage capacity of one depleted gas reservoir is  
680 significantly higher when compared to energy storage capacities of salt caverns,  
681 gasometer tanks, and extended pipelines.
- 682 iv. So far geological aquifer formations are proven realistic storing media for  $CH_4$  rather  
683 than  $H_2$ . Moreover, the aquifers do not contain residual hydrocarbon saturation which  
684 may affect the composition of  $H_2$ . However, the  $H_2$  storage operator is required to

fulfil additional exploration costs. Additionally, aquifers may contain microorganisms that can react with  $H_2$  and ensure precipitation mechanism in the porous media; thus, the permeability of the reservoir can be influenced. Additionally, dissolution of  $H_2$  in aquifers may not be negligible because of the huge amount of available water.

- v. Salt caverns are proven for  $H_2$  storage capacity and security. Nevertheless, salt caverns have very low-storage capacities in several orders of magnitudes (areal extent and height) when compared with depleted gas fields. Additionally, salt cavern wall's thermal stability, microorganism contaminations and  $H_2$  withdrawing ability are challenges to be overcome for its implementation in struggling economies. Thus, by resolving the said challenges in salt caverns, we can explicitly exploit the potential of realistic, clean, high efficiency, futuristic energy storage system.

## **7 Future road map and recommendations for underground $H_2$ energy storage**

Following recommendations are proposed after a thorough analysis of the literature relative to underground  $H_2$  storage case.

- i. Depleted oil and gas reservoirs with rich exploration, and geological drilling order data, and high storage volume can be used for  $H_2$  storage projects. However, anthropogenic activity, biological transformation, in-situ  $H_2/CH_4$ /cushion gas mixing can influence withdrawing/injection cycles and stored gas quality, and security. At some point, anthropogenic activity can be minimized via adequate drilling fluid additives and completion fluid additives which can inhibit mineralogical alteration and microbial life. Mixed gas can be utilized for heating and other purpose based on BTU of the gas.
- ii. Multiple  $H_2$  withdrawal/injection cycle may raise in-situ thermal and pressure variation in the reservoir which results in mineral dissolution altering reservoir permeability and sealing capacity. The effect of physical and thermal stresses in the reservoir requires further investigation, coupling abiotic reactions e.g., pyrite can transform to pyrrhotite causing  $H_2S$  release. However,  $H_2$  did not occur any mineralogical alteration in sandstone. Nevertheless, the reaction of  $H_2$  on carbonate and shale is yet to be answered.

- 714     iii.    Biotic transformation in the storage rock varies with different factors including  
715            temperature, brine water activity, salinities and pH. Microbial activity can develop  
716            biofilms that can plug  $H_2$  flow in the porous media and impair permeability.  
717            Additionally, the indigenous halophilic hyperthermal nature of bacteria can be  
718            critically relevant to  $H_2$  storage. Nevertheless, the effect of microbial activity can  
719            inhibit at high temperature and high salinity environment and addition of microbial  
720            resistant inhibitors
- 721     iv.    Tiny  $H_2$  molecules have high dispersion which may develop a gas slippage effect in the  
722            salt caverns and  $H_2$  can diffuse through the cavern and can raise the permeability  
723            damage resulting problem during withdrawing the  $H_2$ . Thus, it is recommended to  
724            investigate the permeability of the salt cavern formation using  $H_2$  gas. The  
725            aforementioned case can help us to understand the optimized case of the gas cushion,  
726            well performance and sustainability of the overall project.
- 727     v.    Literature review unveiled that salt caverns consist of minerals such as calcite, pyrite,  
728            anhydrite and halite. Thus, halokinesis is an unpredictable natural condition and it may  
729            increase the permeability of the salt layer and develop the problems of the gas  
730            breaching in the cavity. Thus, 90% of salt cavern problems are associated with  $H_2$   
731            leakages and their migration towards wellbore either resulting in corrosion (from  $H_2$   
732            embrittlement) or casing damage (salt creeping) and  $H_2$  losses.

733   Moreover, injection/production cycles of  $H_2$  can influence the geomechanical characteristics  
734   of salt caverns. For this issue, it is recommended that the wellbore can be drilled with tailor-  
735   made (morphology can be tuned) nanomaterial which may invade into the wall of the  
736   wellbore and permanently seal the walls, moreover nanomaterial can be added in the cement  
737   slurry which can adequately seal the annulus between the formation and casing to constrain  
738   the exposure of  $H_2$  in the wellbore. The storing capacity of the salt cavern wells (alone) has  
739   been rarely investigated in the laboratory thus there is a need to examine the behaviour of  
740    $H_2$  with steel tubular (such as casing and tubing) to counter the problems of hydrogen  
741   embrittlement so that technology can be geared up for the LGS purposes. Salt caverns contain  
742   SRB in the bottom of the cavern's sump and fillings. These bacteria can produce  $H_2S$  and can  
743   alter the purity of the stored  $H_2$ . Further,  $H_2S$  may catalyse the process of  $H_2$  embrittlement  
744   and corrosion failure in the completion string. Thus, we recommend examining the behaviour

745 of these microorganisms and their underground activity so that these microorganisms can be  
746 neutralized from further imparting the  $H_2$  storage process.

747 Additionally, microorganism activity and colonization can weak the sealing capacity of  
748 the salt's wall and  $H_2$  pressure in the salt cavern. Thermal energy can influence the  
749 stability of the salt cavern's wall. Thus, there is a further need to examine and test the  
750 strength of the wall under these realistic conditions (such as pressure and  
751 temperature).

## 752 **8 'Supporting information**

753 Supporting information is available free of charge via the Internet at <http://pubs.acs.org/>.

## 754 **9 Acknowledgement**

755

756 We highly appreciate Curtin University, Australia for funding the PhD research studies of **AA**.

## 757 **10 Abbreviations and units**

758

### **Abbreviations**

BP	British Petroleum
EIA	Environmental impact assessment
EUESS	European Union Energy Security and Strategy
GHGE	Greenhouse gases emissions
IRB	Iron-reducing bacteria
IRENA	International renewable energy agency
LGS	Large green-scale
LPG	Liquefied petroleum gas
nD	Nanodarcy
Q1	First quarter
SRB	Sulphate reducing bacteria
UGHS	Underground hydrogen storage

## Units

MJ·kg <sup>-1</sup>	Megajoules per kilogram
cm/s	centimeters per second
cp	centipoise
GWh	Gigawatt-hours
kg·m <sup>-3</sup>	kilogram per cubic metre
mg/l	milligrams per litre
MPa	Megapascal
MJ·kg <sup>-1</sup>	Megajoules per kilogram
MWh	Megawatt-hour
ppm	parts per million

759

760

761

## 762 11 Reference

763

- 764 1. BP Statistical Review of World Energy 2021 | 70th edition.  
765 [https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-](https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2021-full-report.pdf)  
766 [economics/statistical-review/bp-stats-review-2021-full-report.pdf](https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/statistical-review/bp-stats-review-2021-full-report.pdf), Assessed on 21st August, 2021  
767 2. EIA Global Energy Review 2020. [https://www.iea.org/reports/global-energy-review-](https://www.iea.org/reports/global-energy-review-2020/global-energy-and-co2-emissions-in-2020)  
768 [2020/global-energy-and-co2-emissions-in-2020](https://www.iea.org/reports/global-energy-review-2020/global-energy-and-co2-emissions-in-2020) Assessed on 23/01/2021  
769 3. Ou, J.; Wong, I. A.; Huang, G. I., The coevolutionary process of restaurant CSR in the time of  
770 mega disruption. *International Journal of Hospitality Management* **2021**, 92, 102684.  
771 4. Mofijur, M.; Fattah, I. R.; Alam, M. A.; Islam, A. S.; Ong, H. C.; Rahman, S. A.; Najafi, G.;  
772 Ahmed, S.; Uddin, M. A.; Mahlia, T., Impact of COVID-19 on the social, economic, environmental and  
773 energy domains: Lessons learnt from a global pandemic. *Sustainable production and consumption*  
774 **2020**.  
775 5. IRENA, Renewable Energy Prospects for the European Union. **2018**.  
776 6. Energy Energy Road Map (European Energy Strategies).  
777 [https://ec.europa.eu/energy/topics/energy-strategy/previous-energy-strategies\\_en](https://ec.europa.eu/energy/topics/energy-strategy/previous-energy-strategies_en) Assessed on  
778 23/01/2021  
779 7. Kruk, I. Asia's renewable energy future. [https://www.openaccessgovernment.org/asias-](https://www.openaccessgovernment.org/asias-renewable-energy-future/114063/)  
780 [renewable-energy-future/114063/](https://www.openaccessgovernment.org/asias-renewable-energy-future/114063/), Assessed on 21st August, 2021  
781 8. EIA The United States consumed a record amount of renewable energy in 2020.  
782 [https://www.eia.gov/todayinenergy/detail.php?id=48396#:~:text=In%202020%2C%20consumption](https://www.eia.gov/todayinenergy/detail.php?id=48396#:~:text=In%202020%2C%20consumption%20of%20renewable,of%20total%20U.S.%20energy%20consumption)  
783 [%20of%20renewable,of%20total%20U.S.%20energy%20consumption](https://www.eia.gov/todayinenergy/detail.php?id=48396#:~:text=In%202020%2C%20consumption%20of%20renewable,of%20total%20U.S.%20energy%20consumption), Assessed on 21st August,  
784 2021

9. Jurasz, J.; Canales, F.; Kies, A.; Guezgouz, M.; Beluco, A., A review on the complementarity of renewable energy sources: Concept, metrics, application and future research directions. *Solar Energy* **2020**, *195*, 703-724.
10. Barhoumi, E. M.; Farhani, S.; Okonkwo, P. C.; Zghaibeh, M.; Bacha, F., Techno-economic sizing of renewable energy power system case study Dhofar Region-Oman. *International Journal of Green Energy* **2021**, 1-10.
11. Xiong, L.; Li, P.; Wang, Z.; Wang, J., Multi-agent based multi objective renewable energy management for diversified community power consumers. *Applied energy* **2020**, *259*, 114140.
12. Nwaigwe, K.; Mutabilwa, P.; Dintwa, E., An overview of solar power (PV systems) integration into electricity grids. *Materials Science for Energy Technologies* **2019**, *2*, (3), 629-633.
13. Kalair, A.; Abas, N.; Saleem, M. S.; Kalair, A. R.; Khan, N., Role of energy storage systems in energy transition from fossil fuels to renewables. *Energy Storage* **2020**, e135.
14. Kanna, R. R.; Baranidharan, M.; Singh, R. R.; Indragandhi, V. In *Solar Energy Application in Indian Irrigation System*, IOP Conference Series: Materials Science and Engineering, 2020; IOP Publishing: 2020; p 012016.
15. Rehbein, J. A.; Watson, J. E.; Lane, J. L.; Sonter, L. J.; Venter, O.; Atkinson, S. C.; Allan, J. R., Renewable energy development threatens many globally important biodiversity areas. *Global change biology* **2020**, *26*, (5), 3040-3051.
16. İlkiliç, C.; Türkbay, İ., Determination and utilization of wind energy potential for Turkey. *Renewable and Sustainable Energy Reviews* **2010**, *14*, (8), 2202-2207.
17. Sherif, S. A.; Barbir, F.; Veziroglu, T., Wind energy and the hydrogen economy—review of the technology. *Solar energy* **2005**, *78*, (5), 647-660.
18. Rezaei, M.; Naghdi-Khozani, N.; Jafari, N., Wind energy utilization for hydrogen production in an underdeveloped country: An economic investigation. *Renewable Energy* **2020**, *147*, 1044-1057.
19. Guo, B.; Wang, D.; Zhou, J.; Shi, W.; Zhou, X., Performance evaluation of a submerged tidal energy device with a single mooring line. *Ocean Engineering* **2020**, *196*, 106791.
20. Wani, F.; Dong, J.; Polinder, H., *Tidal Turbine Generators*. IntechOpen: London, United Kingdom, 2020; p 43.
21. Neto, P. B. L.; Saavedra, O. R.; Oliveira, D. Q., The effect of complementarity between solar, wind and tidal energy in isolated hybrid microgrids. *Renewable Energy* **2020**, *147*, 339-355.
22. Hooper, T.; Hattam, C.; Edwards-Jones, A.; Beaumont, N., Public perceptions of tidal energy: Can you predict social acceptability across coastal communities in England? *Marine Policy* **2020**, *119*, 104057.
23. Chowdhury, M.; Rahman, K. S.; Selvanathan, V.; Nuthammachot, N.; Suklueng, M.; Mostafaiepour, A.; Habib, A.; Akhtaruzzaman, M.; Amin, N.; Techato, K., Current trends and prospects of tidal energy technology. *Environment, Development and Sustainability* **2020**, 1-16.
24. Koc, M.; Tukenmez, N.; Ozturk, M., Development and thermodynamic assessment of a novel solar and biomass energy based integrated plant for liquid hydrogen production. *International Journal of Hydrogen Energy* **2020**, *45*, (60), 34587-34607.
25. Hadjixenophontos, E.; Dematteis, E. M.; Berti, N.; Wołczyk, A. R.; Huen, P.; Brighi, M.; Le, T. T.; Santoru, A.; Payandeh, S.; Peru, F., A Review of the MSCA ITN ECOSTORE—Novel Complex Metal Hydrides for Efficient and Compact Storage of Renewable Energy as Hydrogen and Electricity. *Inorganics* **2020**, *8*, (3), 17.
26. Finke, C. E.; Leandri, H. F.; Karumb, E. T.; Zheng, D.; Hoffmann, M. R.; Fromer, N. A., Economically advantageous pathways for reducing greenhouse gas emissions from industrial hydrogen under common, current economic conditions. *Energy & Environmental Science* **2021**, *14*, (3), 1517-1529.
27. Yoo, E.; Kim, M.; Song, H. H., Well-to-wheel analysis of hydrogen fuel-cell electric vehicle in Korea. *International Journal of Hydrogen Energy* **2018**, *43*, (41), 19267-19278.
28. IEA The Future of Hydrogen. <https://www.iea.org/reports/the-future-of-hydrogen> Assessed on 24/01/2021



29. Sedaghat, A.; Mostafaeipour, A.; Rezaei, M.; Jahangiri, M.; Mehrabi, A., A new semi-empirical wind turbine capacity factor for maximizing annual electricity and hydrogen production. *International Journal of Hydrogen Energy* **2020**, 45, (32), 15888-15903.
30. Xu, J.; Gao, J.; Wang, W.; Wang, C.; Wang, L., Noble metal-free NiCo nanoparticles supported on montmorillonite/MoS<sub>2</sub> heterostructure as an efficient UV–visible light-driven photocatalyst for hydrogen evolution. *International Journal of Hydrogen Energy* **2018**, 43, (3), 1375-1385.
31. Chen, L.; Yang, W.; Liu, X.; Jia, J., Flower-like CoS<sub>2</sub>/MoS<sub>2</sub> nanocomposite with enhanced electrocatalytic activity for hydrogen evolution reaction. *International Journal of Hydrogen Energy* **2017**, 42, (17), 12246-12253.
32. Cho, R. Why We Need Green Hydrogen. <https://blogs.ei.columbia.edu/2021/01/07/need-green-hydrogen/> Assessed on 24/01/2021
33. Caglayan, D. G.; Weber, N.; Heinrichs, H. U.; Linßen, J.; Robinius, M.; Kukla, P. A.; Stolten, D., Technical potential of salt caverns for hydrogen storage in Europe. *International Journal of Hydrogen Energy* **2020**, 45, (11), 6793-6805.
34. Stan, C., Alternative drives for motor cars. Hybrid systems, fuel cells, alternative energy sources. ; Alternative Antriebe fuer Automobile. Hybridsysteme, Brennstoffzellen, alternative Energietraeger. **2012**.
35. Abe, J. O.; Popoola, A.; Ajenifuja, E.; Popoola, O., Hydrogen energy, economy and storage: review and recommendation. *International Journal of Hydrogen Energy* **2019**, 44, (29), 15072-15086.
36. Milani, D.; Kiani, A.; McNaughton, R., Renewable-powered hydrogen economy from Australia's perspective. *International Journal of Hydrogen Energy* **2020**, 45, (46), 24125-24145.
37. Hassanpouryouzband, A.; Joonaki, E.; Edlmann, K.; Haszeldine, R. S., Offshore Geological Storage of Hydrogen: Is This Our Best Option to Achieve Net-Zero? *ACS Energy Letters* **2021**, 6, 2181-2186.
38. Al-Yaseri, A.; Jha, N. K., On hydrogen wettability of basaltic rock. *Journal of Petroleum Science and Engineering* **2021**, 200, 108387.
39. Dopffel, N.; Jansen, S.; Gerritse, J., Microbial side effects of underground hydrogen storage—Knowledge gaps, risks and opportunities for successful implementation. *International Journal of Hydrogen Energy* **2021**, 46, (12), 8594-8606.
40. Gaol, C. L.; Ganzer, L.; Mukherjee, S.; Alkan, H., Investigation of clogging in porous media induced by microorganisms using a microfluidic application. *Environmental Science: Water Research & Technology* **2021**, 7, (2), 441-454.
41. Rasheed, Z.; Raza, A.; Gholami, R.; Rabiei, M.; Ismail, A.; Rasouli, V., A numerical study to assess the effect of heterogeneity on CO<sub>2</sub> storage potential of saline aquifers. *Energy Geoscience* **2020**, 1, (1-2), 20-27.
42. Vasheghani Farahani, M.; Foroughi, S.; Norouzi, S.; Jamshidi, S., Mechanistic study of fines migration in porous media using lattice Boltzmann method coupled with rigid body physics engine. *Journal of Energy Resources Technology* **2019**, 141, (12).
43. Farahani, M. V.; Guo, X.; Zhang, L.; Yang, M.; Hassanpouryouzband, A.; Zhao, J.; Yang, J.; Song, Y.; Tohidi, B., Effect of thermal formation/dissociation cycles on the kinetics of formation and pore-scale distribution of methane hydrates in porous media: a magnetic resonance imaging study. *Sustainable Energy & Fuels* **2021**, 5, (5), 1567-1583.
44. Roshani, M. M.; Rostaminikoo, E.; Joonaki, E.; Dastjerdi, A. M.; Najafi, B.; Taghikhani, V.; Hassanpouryouzband, A., Applications of the quartz crystal microbalance in energy and environmental sciences: From flow assurance to nanotechnology. *Fuel* **2022**, 313, 122998.
45. Pająk, L.; Lankof, L.; Tomaszewska, B.; Wojnarowski, P.; Janiga, D., The Development of the Temperature Disturbance Zone in the Surrounding of a Salt Cavern Caused by the Leaching Process for Safety Hydrogen Storage. *Energies* **2021**, 14, (4), 803.
46. Farahani, S. S.; Bleeker, C.; van Wijk, A.; Lukszo, Z., Hydrogen-based integrated energy and mobility system for a real-life office environment. *Applied Energy* **2020**, 264, 114695.

47. Han, Y.; Ma, H.; Yang, C.; Li, H.; Yang, J., The mechanical behavior of rock salt under different confining pressure unloading rates during compressed air energy storage (CAES). *Journal of Petroleum Science and Engineering* **2021**, 196, 107676.
48. Liu, W.; Zhang, X.; Fan, J.; Li, Y.; Wang, L., Evaluation of potential for salt cavern gas storage and integration of brine extraction: cavern utilization, Yangtze River Delta region. *Natural Resources Research* **2020**, 29, (5), 3275-3290.
49. Laban, M., Hydrogen Storage in Salt Caverns: Chemical modelling and analysis of large-scale hydrogen storage in underground salt caverns. **2020**.
50. Eliaz, N.; Shachar, A.; Tal, B.; Eliezer, D., Characteristics of hydrogen embrittlement, stress corrosion cracking and tempered martensite embrittlement in high-strength steels. *Engineering Failure Analysis* **2002**, 9, (2), 167-184.
51. Luo, H.; Sohn, S. S.; Lu, W.; Li, L.; Li, X.; Soundararajan, C. K.; Krieger, W.; Li, Z.; Raabe, D., A strong and ductile medium-entropy alloy resists hydrogen embrittlement and corrosion. *Nature communications* **2020**, 11, (1), 1-8.
52. Abdalsamed, I. A.; Amar, I. A.; Altohami, F. A.; Salih, F. A.; Mazek, M. S.; Ali, M. A.; Sharif, A. A., Corrosion Strategy in Oil Field System. *Journal of Chemical Reviews* **2020**, 2, (1), 28-39.
53. Zivar, D.; Kumar, S.; Foroozesh, J., Underground hydrogen storage: A comprehensive review. *International Journal of Hydrogen Energy* **2020**, 46, (45), 23436-23462.
54. Thaysen, E. M.; McMahon, S.; Strobel, G. J.; Butler, I. B.; Ngwenya, B. T.; Heinemann, N.; Wilkinson, M.; Hassanpouryouzband, A.; McDermott, C. I.; Edlmann, K., Estimating microbial growth and hydrogen consumption in hydrogen storage in porous media. *Renewable and Sustainable Energy Reviews* **2021**, 151, 111481.
55. Heinemann, N.; Alcalde, J.; Miocic, J. M.; Hangx, S. J.; Kallmeyer, J.; Ostertag-Henning, C.; Hassanpouryouzband, A.; Thaysen, E. M.; Strobel, G. J.; Schmidt-Hattenberger, C., Enabling large-scale hydrogen storage in porous media—the scientific challenges. *Energy & Environmental Science* **2021**, 14, (2), 853-864.
56. Heinemann, N.; Scafidi, J.; Pickup, G.; Thaysen, E.; Hassanpouryouzband, A.; Wilkinson, M.; Satterley, A.; Booth, M.; Edlmann, K.; Haszeldine, R., Hydrogen storage in saline aquifers: The role of cushion gas for injection and production. *International Journal of Hydrogen Energy* **2021**, 46, (79), 39284-39296.
57. Kushner, D. J., *Microbial life in extreme environments*. Academic Press: 1978.
58. Stewart, L. C.; Jung, J.-H.; Kim, Y.-T.; Kwon, S.-W.; Park, C.-S.; Holden, J. F., *Methanocaldococcus bathoardescens* sp. nov., a hyperthermophilic methanogen isolated from a volcanically active deep-sea hydrothermal vent. *International journal of systematic and evolutionary microbiology* **2015**, 65, (Pt\_4), 1280-1283.
59. Bräuer, S. L.; Cadillo-Quiroz, H.; Ward, R. J.; Yavitt, J. B.; Zinder, S. H., *Methanoregula boonei* gen. nov., sp. nov., an acidiphilic methanogen isolated from an acidic peat bog. *International journal of systematic and evolutionary microbiology* **2011**, 61, (1), 45-52.
60. Ganzert, L.; Schirmack, J.; Alawi, M.; Mangelsdorf, K.; Sand, W.; Hillebrand-Voiculescu, A.; Wagner, D., *Methanosarcina spelaei* sp. nov., a methanogenic archaeon isolated from a floating biofilm of a subsurface sulphurous lake. *International journal of systematic and evolutionary microbiology* **2014**, 64, (Pt\_10), 3478-3484.
61. Zhilina, T.; Zavarzina, D.; Kevbrin, V.; Kolganova, T., *Methanocalculus natronophilus* sp. nov., a new alkaliphilic hydrogenotrophic methanogenic archaeon from a soda lake, and proposal of the new family Methanocalculaceae. *Microbiology* **2013**, 82, (6), 698-706.
62. Chen, Y.; Cheng, J. J.; Creamer, K. S., Inhibition of anaerobic digestion process: a review. *Bioresource technology* **2008**, 99, (10), 4044-4064.
63. Jakobsen, T. F.; Kjeldsen, K. U.; Ingvorsen, K., *Desulfohalobium utahense* sp. nov., a moderately halophilic, sulfate-reducing bacterium isolated from Great Salt Lake. *International journal of systematic and evolutionary microbiology* **2006**, 56, (9), 2063-2069.

64. Ollivier, B.; Hatchikian, C.; Prensier, G.; Guezennec, J.; Garcia, J.-L., *Desulfohalobium retbaense* gen. nov., sp. nov., a halophilic sulfate-reducing bacterium from sediments of a hypersaline lake in Senegal. *International Journal of Systematic and Evolutionary Microbiology* **1991**, 41, (1), 74-81.
65. O'Flaherty, V.; Mahony, T.; O'Kennedy, R.; Colleran, E., Effect of pH on growth kinetics and sulphide toxicity thresholds of a range of methanogenic, syntrophic and sulphate-reducing bacteria. *Process Biochemistry* **1998**, 33, (5), 555-569.
66. Strobel, G.; Hagemann, B.; Huppertz, T. M.; Ganzer, L., Underground bio-methanation: Concept and potential. *Renewable and Sustainable Energy Reviews* **2020**, 123, 109747.
67. Sorokin, D. Y.; Muyzer, G., *Desulfurispira natronophila* gen. nov. sp. nov.: an obligately anaerobic dissimilatory sulfur-reducing bacterium from soda lakes. *Extremophiles* **2010**, 14, (4), 349-355.
68. Dang, P. N.; Dang, T. C. H.; Lai, T. H.; Stan-Lotter, H., *Desulfovibrio vietnamensis* sp. nov., a Halophilic Sulfate-Reducing Bacterium from Vietnamese Oil Fields. *Anaerobe* **1996**, 2, (6), 385-392.
69. Fliermans, C. B.; Brock, T. D., Ecology of sulfur-oxidizing bacteria in hot acid soils. *Journal of Bacteriology* **1972**, 111, (2), 343-350.
70. Schnürer, A.; Schink, B.; Svensson, B. H., *Clostridium ultunense* sp. nov., a mesophilic bacterium oxidizing acetate in syntrophic association with a hydrogenotrophic methanogenic bacterium. *International Journal of Systematic and Evolutionary Microbiology* **1996**, 46, (4), 1145-1152.
71. Abe, F.; Kato, C.; Horikoshi, K., Pressure-regulated metabolism in microorganisms. *Trends in microbiology* **1999**, 7, (11), 447-453.
72. Shi, Z.; Jessen, K.; Tsotsis, T. T., Impacts of the subsurface storage of natural gas and hydrogen mixtures. *International Journal of Hydrogen Energy* **2020**, 45, (15), 8757-8773.
73. Yen, T. F., *Microbial Enhanced Oil Recovery: Principle and Practice*. CRC Press, Inc: Boca Raton, Florida, 1989; p 29-31.
74. Hassanpouryouzband, A.; Joonaki, E.; Edlmann, K.; Heinemann, N.; Yang, J., Thermodynamic and transport properties of hydrogen containing streams. *Scientific Data* **2020**, 7, (1), 1-14.
75. Zhou, Z.; Benbouzid, M.; Charpentier, J. F.; Scuiller, F.; Tang, T., A review of energy storage technologies for marine current energy systems. *Renewable and Sustainable Energy Reviews* **2013**, 18, 390-400.
76. Moench, T. T.; Zeikus, J., Nutritional growth requirements for *Butyrivibrio* methylophilum on single carbon substrates and glucose. *Current Microbiology* **1983**, 9, (3), 151-154.
77. Gregory, S. P.; Barnett, M. J.; Field, L. P.; Milodowski, A. E., Subsurface microbial hydrogen cycling: Natural occurrence and implications for industry. *Microorganisms* **2019**, 7, (2), 53.
78. Carden, P.; Paterson, L., Physical, chemical and energy aspects of underground hydrogen storage. *International Journal of Hydrogen Energy* **1979**, 4, (6), 559-569.
79. Tarkowski, R., Underground hydrogen storage: Characteristics and prospects. *Renewable and Sustainable Energy Reviews* **2019**, 105, 86-94.
80. Le Duigou, A.; Bader, A.-G.; Lanoix, J.-C.; Nadau, L., Relevance and costs of large scale underground hydrogen storage in France. *International Journal of Hydrogen Energy* **2017**, 42, (36), 22987-23003.
81. Hassanpouryouzband, A.; Edlmann, K.; Wilkinson, M. In *Geochemistry of Geological Hydrogen Storage in Sandstone Reservoirs*, EGU General Assembly Conference Abstracts, 2021; 2021; pp EGU21-9894.
82. Oku, T.; Narita, I., Calculation of H<sub>2</sub> gas storage for boron nitride and carbon nanotubes studied from the cluster calculation. *Physica B: Condensed Matter* **2002**, 323, (1-4), 216-218.
83. Sharma, S.; Ghoshal, S. K., Hydrogen the future transportation fuel: From production to applications. *Renewable and sustainable energy reviews* **2015**, 43, 1151-1158.

84. Sherwood Lollar, B.; Voglesonger, K.; Lin, L.-H.; Lacrampe-Couloume, G.; Telling, J.; Abrajano, T.; Onstott, T. C.; Pratt, L., Hydrogeologic controls on episodic H<sub>2</sub> release from Precambrian fractured rocks—energy for deep subsurface life on Earth and Mars. *Astrobiology* **2007**, 7, (6), 971-986.
85. Hassanpouryouzband, A.; Joonaki, E.; Farahani, M. V.; Takeya, S.; Ruppel, C.; Yang, J.; English, N. J.; Schicks, J. M.; Edlmann, K.; Mehrabian, H., Gas hydrates in sustainable chemistry. *Chemical Society Reviews* **2020**, 49, (15), 5225-5309.
86. Luidold, S.; Antrekowitsch, H., Hydrogen as a reducing agent: State-of-the-art science and technology. *Jom* **2007**, 59, (6), 20-26.
87. Truche, L.; Berger, G.; Destrigneville, C.; Guillaume, D.; Giffaut, E., Kinetics of pyrite to pyrrhotite reduction by hydrogen in calcite buffered solutions between 90 and 180 C: Implications for nuclear waste disposal. *Geochimica et Cosmochimica Acta* **2010**, 74, (10), 2894-2914.
88. Hall, A., Pyrite-pyrrhotine redox reactions in nature. *Mineralogical Magazine* **1986**, 50, (356), 223-229.
89. Yekta, A. E.; Pichavant, M.; Audigane, P., Evaluation of geochemical reactivity of hydrogen in sandstone: Application to geological storage. *Applied Geochemistry* **2018**, 95, 182-194.
90. Thaysen, E. M.; McMahon, S.; Strobel, G. J.; Butler, I. B.; Ngwenya, B.; Heinemann, N.; Wilkinson, M.; Hassanpouryouzband, A.; McDermott, C. I.; Edlmann, K. In *Site Selection Tool for Hydrogen Storage in Porous Media*, EGU General Assembly Conference Abstracts, 2021; 2021; pp EGU21-8883.
91. Yuan, H.; Chen, Y.; Zhang, H.; Jiang, S.; Zhou, Q.; Gu, G., Improved bioproduction of short-chain fatty acids (SCFAs) from excess sludge under alkaline conditions. *Environmental science & technology* **2006**, 40, (6), 2025-2029.
92. Almahamedh, H. H. In *Sulfate reducing bacteria influenced calcium carbonate precipitation*, CORROSION 2013, 2013; NACE International: 2013.
93. Lin, C. Y.; Turchyn, A. V.; Steiner, Z.; Bots, P.; Lampronti, G. I.; Tosca, N. J., The role of microbial sulfate reduction in calcium carbonate polymorph selection. *Geochimica et Cosmochimica Acta* **2018**, 237, 184-204.
94. Chapelle, F. H.; O'Neill, K.; Bradley, P. M.; Methé, B. A.; Ciufo, S. A.; Knobel, L. L.; Lovley, D. R., A hydrogen-based subsurface microbial community dominated by methanogens. *Nature* **2002**, 415, (6869), 312-315.
95. Joye, S. B., A piece of the methane puzzle. *Nature* **2012**, 491, (7425), 538-539.
96. Kleintz, W.; Boehling, E. In *Underground gas storage in porous media—operating experience with bacteria on gas quality (spe94248)*, 67th EAGE Conference & Exhibition, 2005; European Association of Geoscientists & Engineers: 2005; pp cp-1-00556.
97. Thaysen, E. M.; McMahon, S.; Strobel, G.; Butler, I.; Ngwenya, B.; Heinemann, N.; Wilkinson, M.; Hassanpouryouzband, A.; McDermott, C.; Edlmann, K., – Estimating Microbial Hydrogen Consumption in Hydrogen Storage in Porous Media as a Basis for Site Selection. **2020**.
98. Pannekens, M.; Kroll, L.; Müller, H.; Mbow, F. T.; Meckenstock, R. U., Oil reservoirs, an exceptional habitat for microorganisms. *New biotechnology* **2019**, 49, 1-9.
99. Wong, D.; Suflita, J.; McKinley, J.; Krumholz, L., Impact of clay minerals on sulfate-reducing activity in aquifers. *Microbial Ecology* **2004**, 47, (1), 80-86.
100. Ratnayaka, D. D.; Brandt, M. J.; Johnson, K. M., CHAPTER 6 - Chemistry, Microbiology and Biology of Water. In *Water Supply (Sixth Edition)*, Ratnayaka, D. D.; Brandt, M. J.; Johnson, K. M., Eds. Butterworth-Heinemann: Boston, 2009; pp 195-266.
101. Vance, I.; Thrasher, D. R., Reservoir souring: mechanisms and prevention. *Petroleum microbiology* **2005**, 123-142.
102. Eckford, R.; Fedorak, P., Planktonic nitrate-reducing bacteria and sulfate-reducing bacteria in some western Canadian oil field waters. *Journal of Industrial Microbiology and Biotechnology* **2002**, 29, (2), 83-92.

103. Barton, L. L.; Hamilton, W. A., *Sulphate-reducing bacteria: environmental and engineered systems*. Cambridge University Press: 2007.
104. Koschorreck, M., Microbial sulphate reduction at a low pH. *FEMS Microbiology Ecology* **2008**, 64, (3), 329-342.
105. Hubert, C.; Voordouw, G., Oil field souring control by nitrate-reducing *Sulfurospirillum* spp. that outcompete sulfate-reducing bacteria for organic electron donors. *Applied and environmental microbiology* **2007**, 73, (8), 2644.
106. Hamilton, W. A., Sulphate-reducing bacteria and anaerobic corrosion. *Annual review of microbiology* **1985**, 39, (1), 195-217.
107. Enning, D.; Garrelfs, J., Corrosion of iron by sulfate-reducing bacteria: new views of an old problem. *Applied and environmental microbiology* **2014**, 80, (4), 1226.
108. Lin, S.; Krause, F.; Voordouw, G., Transformation of iron sulfide to greigite by nitrite produced by oil field bacteria. *Applied microbiology and biotechnology* **2009**, 83, (2), 369-376.
109. Robinson, M.; Kilgallon, P., Hydrogen embrittlement of cathodically protected high-strength, low-alloy steels exposed to sulfate-reducing bacteria. *Corrosion* **1994**, 50, (8), 626-635.
110. Bergaya, F.; Lagaly, G., *Handbook of clay science*. Newnes: 2013.
111. Liu, D.; Dong, H.; Agrawal, A.; Singh, R.; Zhang, J.; Wang, H., Inhibitory effect of clay mineral on methanogenesis by *Methanosarcina mazei* and *Methanothermobacter thermautotrophicus*. *Applied Clay Science* **2016**, 126, 25-32.
112. Aravena, R.; Wassenaar, L. I.; Plummer, L. N., Estimating <sup>14</sup>C groundwater ages in a methanogenic aquifer. *Water Resources Research* **1995**, 31, (9), 2307-2317.
113. Fu, Y.; van Berk, W.; Schulz, H.-M., Hydrogen sulfide formation, fate, and behavior in anhydrite-sealed carbonate gas reservoirs: A three-dimensional reactive mass transport modeling approach. *AAPG Bulletin* **2016**, 100, (5), 843-865.
114. Schieder, D.; Quicker, P.; Schneider, R.; Winter, H.; Prechtel, S.; Faulstich, M., Microbiological removal of hydrogen sulfide from biogas by means of a separate biofilter system: experience with technical operation. *Water Science and Technology* **2003**, 48, (4), 209-212.
115. Lord, A. S.; Kobos, P. H.; DJ, B., A Life Cycle Cost Analysis Framework for Geologic Storage of Hydrogen. In SAND2009-6310: 2009.
116. Løseth, H.; Gading, M.; Wensaas, L., Hydrocarbon leakage interpreted on seismic data. *Marine and Petroleum Geology* **2009**, 26, (7), 1304-1319.
117. Arndt, N. T.; Fontboté, L.; Hedenquist, J. W.; Kesler, S. E.; Thompson, J. F.; Wood, D. G., Future global mineral resources. *Geochemical Perspectives* **2017**, 6, (1), 1-171.
118. Seman, L. O.; Giuliani, C. M.; Camponogara, E.; Müller, E. R.; Vieira, B. F.; Miyatake, L. K.; Medeiros, A. G., Tuning of oil well models with production data reconciliation. *Computers & Chemical Engineering* **2021**, 145, 107179.
119. Bai, M.; Song, K.; Sun, Y.; He, M.; Li, Y.; Sun, J., An overview of hydrogen underground storage technology and prospects in China. *Journal of Petroleum Science and Engineering* **2014**, 124, 132-136.
120. Aftab, A.; Ali, M.; Arif, M.; Panhwar, S.; Saady, N. M. C.; Al-Khdheawi, E. A.; Mahmoud, O.; Ismail, A. R.; Keshavarz, A.; Iglaue, S., Influence of tailor-made TiO<sub>2</sub>/API bentonite nanocomposite on drilling mud performance: Towards enhanced drilling operations. *Applied Clay Science* **2020**, 199, 105862.
121. Amid, A.; Mignard, D.; Wilkinson, M., Seasonal storage of hydrogen in a depleted natural gas reservoir. *International journal of hydrogen energy* **2016**, 41, (12), 5549-5558.
122. Ranchou-Peyruse, M.; Auguet, J. C.; Mazière, C.; Restrepo-Ortiz, C. X.; Guignard, M.; Dequidt, D.; Chiquet, P.; Cézac, P.; Ranchou-Peyruse, A., Geological gas-storage shapes deep life. *Environmental microbiology* **2019**, 21, (10), 3953-3964.
123. Pudlo, D.; Flesch, S.; Albrecht, D.; Reitenbach, V. In *The impact of hydrogen on potential underground energy reservoirs*, EGU General Assembly Conference Abstracts, 2018; 2018; p 8606.

124. Lord, A. S., Overview of geologic storage of natural gas with an emphasis on assessing the feasibility of storing hydrogen. *SAND2009-5878, Sandia Natl. Lab. Albuquerque, NM* **2009**.
125. Tarkowski, R., Perspectives of using the geological subsurface for hydrogen storage in Poland. *International Journal of Hydrogen Energy* **2017**, 42, (1), 347-355.
126. Worthington, S. H.; Ford, D. C.; Beddows, P. A. In *Porosity and permeability enhancement in unconfined carbonate aquifers as a result of dissolution*, SPELEO Brazil 2001-13th International Congress of Speleology, 2001; 2001.
127. Dong, J.-J.; Hsu, J.-Y.; Wu, W.-J.; Shimamoto, T.; Hung, J.-H.; Yeh, E.-C.; Wu, Y.-H.; Sone, H., Stress-dependence of the permeability and porosity of sandstone and shale from TCDP Hole-A. *International Journal of Rock Mechanics and Mining Sciences* **2010**, 47, (7), 1141-1157.
128. Michael, K.; Golab, A.; Shulakova, V.; Ennis-King, J.; Allinson, G.; Sharma, S.; Aiken, T., Geological storage of CO<sub>2</sub> in saline aquifers—A review of the experience from existing storage operations. *International journal of greenhouse gas control* **2010**, 4, (4), 659-667.
129. Soupios, P. M.; Kouli, M.; Vallianatos, F.; Vafidis, A.; Stavroulakis, G., Estimation of aquifer hydraulic parameters from surficial geophysical methods: A case study of Keritis Basin in Chania (Crete–Greece). *Journal of Hydrology* **2007**, 338, (1-2), 122-131.
130. McCoy, S. T. The Economics of CO<sub>2</sub>, Transport by Pipeline and Storage in Saline Aquifers and Oil Reservoirs. Sean T. McCoy, 2008.
131. Lavrov, A.; Torsæter, M., *Physics and mechanics of primary well cementing*. Springer Nature: Switzerland, 2016; p 4-16.
132. Sáinz-García, A.; Abarca, E.; Rubí, V.; Grandia, F., Assessment of feasible strategies for seasonal underground hydrogen storage in a saline aquifer. *International Journal of Hydrogen Energy* **2017**, 42, (26), 16657-16666.
133. Weymer, B. A.; Wernette, P. A.; Everett, M. E.; Pondthai, P.; Jegen, M.; Micallef, A., Multi-layered high permeability conduits connecting onshore and offshore coastal aquifers. *Frontiers in Marine Science* **2020**, 7, 903.
134. De Silva, G.; Ranjith, P. G.; Perera, M., Geochemical aspects of CO<sub>2</sub> sequestration in deep saline aquifers: A review. *Fuel* **2015**, 155, 128-143.
135. Lemieux, A.; Sharp, K.; Shkarupin, A., Preliminary assessment of underground hydrogen storage sites in Ontario, Canada. *International Journal of Hydrogen Energy* **2019**, 44, (29), 15193-15204.
136. Kirkland, C. M.; Hiebert, R.; Phillips, A.; Grunewald, E.; Walsh, D. O.; Seymour, J. D.; Codd, S. L., Biofilm detection in a model well-bore environment using low-field NMR. *Groundwater Monitoring & Remediation* **2015**, 35, (4), 36-44.
137. Jones Jr, R. S. In *Producing gas-oil ratio behavior of tight oil reservoirs*, Unconventional Resources Technology Conference, San Antonio, Texas, 1-3 August 2016, 2016; Society of Exploration Geophysicists, American Association of Petroleum ...: 2016; pp 2167-2186.
138. Pfeiffer, W.; Al Hagrey, S.; Köhn, D.; Rabbel, W.; Bauer, S., Porous media hydrogen storage at a synthetic, heterogeneous field site: numerical simulation of storage operation and geophysical monitoring. *Environmental Earth Sciences* **2016**, 75, (16), 1-18.
139. Van Wees, J.-D.; Kronimus, A.; Van Putten, M.; Pluymaekers, M.; Mijnlief, H.; Van Hooff, P.; Obdam, A.; Kramers, L., Geothermal aquifer performance assessment for direct heat production—Methodology and application to Rotliegend aquifers. *Netherlands Journal of Geosciences* **2012**, 91, (4), 651-665.
140. Chabora, E. R.; Benson, S. M., Brine displacement and leakage detection using pressure measurements in aquifers overlying CO<sub>2</sub> storage reservoirs. *Energy Procedia* **2009**, 1, (1), 2405-2412.
141. Sato, K.; Mito, S.; Horie, T.; Ohkuma, H.; Saito, H.; Watanabe, J.; Yoshimura, T., Monitoring and simulation studies for assessing macro-and meso-scale migration of CO<sub>2</sub> sequestered in an onshore aquifer: Experiences from the Nagaoka pilot site, Japan. *International Journal of Greenhouse Gas Control* **2011**, 5, (1), 125-137.

142. Shevalier, M.; Nightingale, M.; Mayer, B.; Hutcheon, I., TOUGHREACT modeling of the fate of CO<sub>2</sub> injected into a H<sub>2</sub>S containing saline aquifer: The example of the Wabamum Area Sequestration Project (WASP). *Energy Procedia* **2011**, 4, 4403-4410.
143. Mathiassen, O., CO<sub>2</sub> storage capacity estimation: Methodology and gaps. *International Journal of Greenhouse Gas Control* **2007**, 1, (4), 430-443.
144. Iglauder, S.; Pentland, C.; Busch, A., CO<sub>2</sub> wettability of seal and reservoir rocks and the implications for carbon geo-sequestration. *Water Resources Research* **2015**, 51, (1), 729-774.
145. Al-Khdheawi, E. A.; Vialle, S.; Barifcani, A.; Sarmadivaleh, M.; Iglauder, S., Influence of CO<sub>2</sub>-wettability on CO<sub>2</sub> migration and trapping capacity in deep saline aquifers. *Greenhouse Gases: Science and Technology* **2017**, 7, (2), 328-338.
146. Vasheghani Farahani, M.; Hassanpouryouzband, A.; Yang, J.; Tohidi, B., Heat transfer in unfrozen and frozen porous media: Experimental measurement and pore-scale modeling. *Water Resources Research* **2020**, 56, (9), e2020WR027885.
147. Farahani, M. V.; Hassanpouryouzband, A.; Yang, J.; Tohidi, B., Insights into the climate-driven evolution of gas hydrate-bearing permafrost sediments: implications for prediction of environmental impacts and security of energy in cold regions. *RSC Advances* **2021**, 11, (24), 14334-14346.
148. Hunten, D. M., The escape of light gases from planetary atmospheres. *Journal of Atmospheric Sciences* **1973**, 30, (8), 1481-1494.
149. Sebők, B.; Schülke, M.; Réti, F.; Kiss, G., Diffusivity, permeability and solubility of H<sub>2</sub>, Ar, N<sub>2</sub>, and CO<sub>2</sub> in poly (tetrafluoroethylene) between room temperature and 180° C. *Polymer Testing* **2016**, 49, 66-72.
150. Iglauder, S.; Ali, M.; Keshavarz, A., Hydrogen Wettability of Sandstone Reservoirs: Implications for Hydrogen Geo-Storage. *Geophysical Research Letters* **2020**, e2020GL090814.
151. Rahman, T.; Lebedev, M.; Barifcani, A.; Iglauder, S., Residual trapping of supercritical CO<sub>2</sub> in oil-wet sandstone. *Journal of colloid and interface science* **2016**, 469, 63-68.
152. Leachman, J. W.; Jacobsen, R. T.; Penoncello, S.; Lemmon, E. W., Fundamental equations of state for parahydrogen, normal hydrogen, and orthohydrogen. *Journal of Physical and Chemical Reference Data* **2009**, 38, (3), 721-748.
153. McCarty, R. D.; Hord, J.; Roder, H. M., *Selected properties of hydrogen (engineering design data)*. US Department of Commerce, National Bureau of Standards: 1981; Vol. 168.
154. Kunz, O.; Wagner, W., The GERG-2008 wide-range equation of state for natural gases and other mixtures: an expansion of GERG-2004. *Journal of chemical & engineering data* **2012**, 57, (11), 3032-3091.
155. Wagner, W.; Pruß, A., The IAPWS formulation 1995 for the thermodynamic properties of ordinary water substance for general and scientific use. *Journal of physical and chemical reference data* **2002**, 31, (2), 387-535.
156. Zuo, Y.-X.; Stenby, E. H., Prediction of interfacial tensions of reservoir crude oil and gas condensate systems. *SPE Journal* **1998**, 3, (02), 134-145.
157. Aguilar-Armenta, G.; Patiño-Iglesias, M. E.; Leyva-Ramos, R., Adsorption kinetic behaviour of pure CO<sub>2</sub>, N<sub>2</sub> and CH<sub>4</sub> in natural clinoptilolite at different temperatures. *Adsorption Science & Technology* **2003**, 21, (1), 81-91.
158. Pal, P., Chapter 5 - Arsenic Removal by Membrane Distillation. In *Groundwater Arsenic Remediation*, Pal, P., Ed. Butterworth-Heinemann: 2015; pp 179-270.
159. Hassanpouryouzband, A.; Farahani, M. V.; Yang, J.; Tohidi, B.; Chuvilin, E.; Istomin, V.; Bukhanov, B., Solubility of flue gas or carbon dioxide-nitrogen gas mixtures in water and aqueous solutions of salts: Experimental measurement and thermodynamic modeling. *Industrial & Engineering Chemistry Research* **2019**, 58, (8), 3377-3394.
160. Wiebe, R.; Gaddy, V., The solubility of carbon dioxide in water at various temperatures from 12 to 40 and at pressures to 500 atmospheres. Critical phenomena. *Journal of the American Chemical Society* **1940**, 62, (4), 815-817.

161. Chen, N. H.; Othmer, D. F., New generalized equation for gas diffusion coefficient. *Journal of Chemical and Engineering Data* **1962**, 7, (1), 37-41.
162. Iglauder, S.; Ali, M.; Keshavarz, A., Hydrogen Wettability of Sandstone Reservoirs: Implications for Hydrogen Geo-Storage. *Geophysical Research Letters* **2021**, 48, (3), e2020GL090814.
163. Hashemi, L.; Blunt, M.; Hajibeygi, H., Pore-scale modelling and sensitivity analyses of hydrogen-brine multiphase flow in geological porous media. *Scientific reports* **2021**, 11, (1), 1-13.
164. Hassannayebi, N.; Azizmohammadi, S.; De Lucia, M.; Ott, H., Underground hydrogen storage: application of geochemical modelling in a case study in the Molasse Basin, Upper Austria. *Environmental Earth Sciences* **2019**, 78, (5), 1-14.
165. Puder, M.; Veil, J. *Offsite commercial disposal of oil and gas exploration and production waste: availability, options, and cost*; Argonne National Lab.(ANL), Argonne, IL (United States): 2006.
166. Portarapillo, M.; Di Benedetto, A., Risk Assessment of the Large-Scale Hydrogen Storage in Salt Caverns. *Energies* **2021**, 14, 2856. In s Note: MDPI stays neu-tral with regard to jurisdictional claims in ...: 2021.
167. Benoit, B.; Pierre, B.; Jean-Yves, H.; Dominique, F., AN IN SITU CREEP TEST IN ADVANCE OF ABANDONING A SALT CAVERN.
168. Lea, J. F.; Nickens, H. V.; Wells, M. R., CHAPTER 1 - INTRODUCTION. In *Gas Well Deliquification (Second Edition)*, Lea, J. F.; Nickens, H. V.; Wells, M. R., Eds. Gulf Professional Publishing: Burlington, 2008; pp 1-11.
169. Guo, B.; Sun, K.; Ghalambor, A., Chapter 7 - Productivity of Wells with Complex Trajectories. *Well Productivity Handbook* **2008**, 217-246.
170. Yin, H.; Yang, C.; Ma, H.; Shi, X.; Zhang, N.; Ge, X.; Li, H.; Han, Y., Stability evaluation of underground gas storage salt caverns with micro-leakage interlayer in bedded rock salt of Jintan, China. *Acta Geotechnica* **2020**, 15, (3), 549-563.
171. Wang, T.; Yang, C.; Yan, X.; Daemen, J., Allowable pillar width for bedded rock salt caverns gas storage. *Journal of Petroleum Science and Engineering* **2015**, 127, 433-444.
172. Wei, L.; Jie, C.; Deyi, J.; Xilin, S.; Yinping, L.; Daemen, J.; Chunhe, Y., Tightness and suitability evaluation of abandoned salt caverns served as hydrocarbon energies storage under adverse geological conditions (AGC). *Applied Energy* **2016**, 178, 703-720.
173. Hamlin, H. S., Salt domes in the Gulf Coast aquifer. *Aquifers of the Gulf Coast of Texas, Mace, RE, Davidson, SC, Angle, ES, and Mullican, WF, eds., Texas Water Development Board, Report* **2006**, 365, 217-230.
174. Mokhatab, S.; Raymand, T., Fundamentals of gas pipeline metering stations. *Pipeline & Gas Journal* **2009**, 236, (1), 3.
175. Berest, P.; Djakeun-Djizanne, H.; Brouard, B.; Frangi, A. In *A simplified solution for Gas Flow during a Blow-out in an H2 or air storage cavern*, SMRI Spring Conference, 22-23 April 2013, 2013; 2013; pp 125-144.
176. Michalski, J.; Bünger, U.; Crotogino, F.; Donadei, S.; Schneider, G.-S.; Pregger, T.; Cao, K.-K.; Heide, D., Hydrogen generation by electrolysis and storage in salt caverns: Potentials, economics and systems aspects with regard to the German energy transition. *International Journal of Hydrogen Energy* **2017**, 42, (19), 13427-13443.
177. Wang, T.; Yang, C.; Wang, H.; Ding, S.; Daemen, J., Debrining prediction of a salt cavern used for compressed air energy storage. *Energy* **2018**, 147, 464-476.
178. Ball, M.; Wietschel, M., The future of hydrogen—opportunities and challenges. *International journal of hydrogen energy* **2009**, 34, (2), 615-627.
179. Dodds, P. E.; Staffell, I.; Hawkes, A. D.; Li, F.; Grünewald, P.; McDowall, W.; Ekins, P., Hydrogen and fuel cell technologies for heating: A review. *International journal of hydrogen energy* **2015**, 40, (5), 2065-2083.
180. Shakya, B.; Aye, L.; Musgrave, P., Technical feasibility and financial analysis of hybrid wind–photovoltaic system with hydrogen storage for Cooma. *International Journal of Hydrogen Energy* **2005**, 30, (1), 9-20.



- 1237 181. Yang, C.; Wang, T.; Li, Y.; Yang, H.; Li, J.; Xu, B.; Yang, Y.; Daemen, J., Feasibility analysis of  
1238 using abandoned salt caverns for large-scale underground energy storage in China. *Applied Energy*  
1239 **2015**, 137, 467-481.
- 1240 182. Zheng, Y.; Wanyan, Q.; Qiu, X.; Kou, Y.; Ran, L.; Lai, X.; Wu, S., New technologies for site  
1241 selection and evaluation of salt-cavern underground gas storages. *Natural Gas Industry B* **2020**, 7,  
1242 (1), 40-48.
- 1243 183. Bellini, E. <https://www.pv-magazine.com/2020/06/16/hydrogen-storage-in-salt-caverns/>.  
1244 <https://www.pv-magazine.com/2020/06/16/hydrogen-storage-in-salt-caverns/> Assessed  
1245 01/02/2020
- 1246 184. Broughton, P. L., Devonian salt dissolution-collapse breccias flooring the Cretaceous  
1247 Athabasca oil sands deposit and development of lower McMurray Formation sinkholes, northern  
1248 Alberta Basin, Western Canada. *Sedimentary Geology* **2013**, 283, 57-82.
- 1249 185. Mège, D.; Le Deit, L.; Rango, T.; Korme, T., Gravity tectonics of topographic ridges:  
1250 Halokinesis and gravitational spreading in the western Ogaden, Ethiopia. *Geomorphology* **2013**, 193,  
1251 1-13.
- 1252 186. Trusheim, F., Mechanism of salt migration in northern Germany. *AAPG Bulletin* **1960**, 44, (9),  
1253 1519-1540.
- 1254 187. Almalki, K. A.; Ailleres, L.; Betts, P. G.; Bantan, R. A., Evidence for and relationship between  
1255 recent distributed extension and halokinesis in the Farasan Islands, southern Red Sea, Saudi Arabia.  
1256 *Arabian Journal of Geosciences* **2015**, 8, (10), 8753-8766.
- 1257 188. Fossen, H., *Structural geology*. Cambridge University Press: 2016.
- 1258 189. Kukla, P. A.; Urai, J. L.; Raith, A.; Li, S.; Barabasz, J.; Strozyk, F., The European Zechstein Salt  
1259 Giant—Trusheim and Beyond. **2019**.
- 1260 190. Chen, J.; Ren, S.; Yang, C.; Jiang, D.; Li, L., Self-healing characteristics of damaged rock salt  
1261 under different healing conditions. *Materials* **2013**, 6, (8), 3438-3450.
- 1262 191. Charlet, L.; Alt-Epping, P.; Wersin, P.; Gilbert, B., Diffusive transport and reaction in clay  
1263 rocks: A storage (nuclear waste, CO<sub>2</sub>, H<sub>2</sub>), energy (shale gas) and water quality issue. *Advances in*  
1264 *Water Resources* **2017**, 106, 39-59.
- 1265 192. Blounot, C.; Dickson, F., The solubility of anhydrite (CaSO<sub>4</sub>) in NaCl-H<sub>2</sub>O from 100 to 450 C  
1266 and 1 to 1000 bars. *Geochimica et Cosmochimica Acta* **1969**, 33, (2), 227-245.
- 1267 193. Newton, R. C.; Manning, C. E., Solubility of anhydrite, CaSO<sub>4</sub>, in NaCl-H<sub>2</sub>O solutions at high  
1268 pressures and temperatures: applications to fluid-rock interaction. *Journal of Petrology* **2005**, 46,  
1269 (4), 701-716.
- 1270 194. Hoffmeister, H., Modeling the effect of chloride content on hydrogen sulfide corrosion of  
1271 pure iron by coupling of phase and polarization behavior. *Corrosion* **2008**, 64, (6), 483-495.
- 1272 195. Oriani, R., The physical and metallurgical aspects of hydrogen in metals. *Fusion Technology*  
1273 **1994**, 26, (4), 235-266.
- 1274 196. Birenis, D. Fundamental investigations of hydrogen embrittlement by using electron  
1275 microscopy. University of Oslo, Oslo, Norway, 2020.
- 1276 197. Munson, D. E.; Molecke, M. A.; Neal, J. T. *Strategic petroleum reserve caverns casing*  
1277 *damage update 1997*; Sandia National Labs., Albuquerque, NM (United States): 1998.
- 1278 198. Rossin, A.; Tuci, G.; Luconi, L.; Giambastiani, G., Metal-organic frameworks as  
1279 heterogeneous catalysts in hydrogen production from lightweight inorganic hydrides. *Acs Catalysis*  
1280 **2017**, 7, (8), 5035-5045.
- 1281 199. Reilly, J. J.; Sandrock, G. D., Hydrogen storage in metal hydrides. *Scientific American* **1980**,  
1282 242, (2), 118-131.
- 1283 200. Cosenza, P.; Ghoreychi, M.; Bazargan-Sabet, B.; De Marsily, G., In situ rock salt permeability  
1284 measurement for long term safety assessment of storage. *International Journal of Rock Mechanics*  
1285 *and Mining Sciences* **1999**, 36, (4), 509-526.
- 1286 201. Bahadori, A., Chapter 1 - Overview of Natural Gas Resources. In *Natural Gas Processing*,  
1287 Bahadori, A., Ed. Gulf Professional Publishing: Boston, 2014; pp 1-22.

202. Xu, J.; Ren, X.; Gao, G., Salt-inactive hydrophobic association hydrogels with fatigue resistant and self-healing properties. *Polymer* **2018**, 150, 194-203.
203. Bordenave, S.; Chatterjee, I.; Voordouw, G., Microbial community structure and microbial activities related to CO<sub>2</sub> storage capacities of a salt cavern. *International Biodeterioration & Biodegradation* **2013**, 81, 82-87.
204. Böttcher, N.; Görke, U.-J.; Kolditz, O.; Nagel, T., Thermo-mechanical investigation of salt caverns for short-term hydrogen storage. *Environmental Earth Sciences* **2017**, 76, (3), 98.
205. Ozarslan, A., Large-scale hydrogen energy storage in salt caverns. *International journal of hydrogen energy* **2012**, 37, (19), 14265-14277.
206. Bhattacharjee, T.; Datta, S. S., Bacterial hopping and trapping in porous media. *Nature communications* **2019**, 10, (1), 1-9.
207. Tarkowski, R.; Czapowski, G., Salt domes in Poland—potential sites for hydrogen storage in caverns. *International Journal of Hydrogen Energy* **2018**, 43, (46), 21414-21427.
208. für Bergbau, L., Energie und Geologie. 2013. *Erdöl und Erdgas in der Bundesrepublik Deutschland* **2010**.
209. Thoms, R.; Gehle, R. In *A brief history of salt cavern use*, Keynote Speech at Salt 2000 Conference, 2000; 2000.
210. Donadei, S.; Schneider, G.-S., Compressed air energy storage in underground formations. In *Storing Energy*, Elsevier: 2016; pp 113-133.
211. Bünger, U.; Michalski, J.; Crotogino, F.; Kruck, O., Large-scale underground storage of hydrogen for the grid integration of renewable energy and other applications. In *Compendium of hydrogen energy*, Elsevier: 2016; pp 133-163.
212. Crotogino, F., Traditional Bulk Energy Storage—Coal and Underground Natural Gas and Oil Storage. In *Storing Energy*, Elsevier: 2016; pp 391-409.
213. Colella, W.; Jacobson, M.; Golden, D., Switching to a US hydrogen fuel cell vehicle fleet: The resultant change in emissions, energy use, and greenhouse gases. *Journal of Power Sources* **2005**, 150, 150-181.
214. Kjeldsen, K. U.; Loy, A.; Jakobsen, T. F.; Thomsen, T. R.; Wagner, M.; Ingvorsen, K., Diversity of sulfate-reducing bacteria from an extreme hypersaline sediment, Great Salt Lake (Utah). *FEMS microbiology ecology* **2007**, 60, (2), 287-298.
215. Postgate, J. R., Recent advances in the study of the sulfate-reducing bacteria. *Bacteriological reviews* **1965**, 29, (4), 425.
216. Cui, J.; Chen, X.; Nie, M.; Fang, S.; Tang, B.; Quan, Z.; Li, B.; Fang, C., Effects of *Spartina alterniflora* invasion on the abundance, diversity, and community structure of sulfate reducing bacteria along a successional gradient of coastal salt marshes in China. *Wetlands* **2017**, 37, (2), 221-232.
217. Hao, O. J.; Chen, J. M.; Huang, L.; Buglass, R. L., Sulfate-reducing bacteria. *Critical reviews in environmental science and technology* **1996**, 26, (2), 155-187.
218. Hemme, C.; van Berk, W., Potential risk of H<sub>2</sub>S generation and release in salt cavern gas storage. *Journal of Natural Gas Science and Engineering* **2017**, 47, 114-123.
219. Hemme, C.; Van Berk, W., Hydrogeochemical modeling to identify potential risks of underground hydrogen storage in depleted gas fields. *Applied Sciences* **2018**, 8, (11), 2282.
220. Nazina, T. N.; Rozanova, E. P.; Kuznetsov, S. I., Microbial oil transformation processes accompanied by methane and hydrogen-sulfide formation. *Geomicrobiology Journal* **1985**, 4, (2), 103-130.
221. Dai, X.; Hu, C.; Zhang, D.; Chen, Y., A new method for the simultaneous enhancement of methane yield and reduction of hydrogen sulfide production in the anaerobic digestion of waste activated sludge. *Bioresource technology* **2017**, 243, 914-921.
222. Raczkowski, J.; Turkiewicz, A.; Kapusta, P. In *Elimination of Biogenic Hydrogen Sulfide in Underground Gas Storage. A Case Study*, SPE Annual Technical Conference and Exhibition, 2004; Society of Petroleum Engineers: 2004.

223. Olson, G.; Dockins, W.; McFeters, G.; Iverson, W. P., Sulfate-reducing and methanogenic bacteria from deep aquifers in montana. *Geomicrobiology Journal* **1981**, 2, (4), 327-340.
224. Tian, G.; Xi, J.; Yeung, M.; Ren, G., Characteristics and mechanisms of H<sub>2</sub>S production in anaerobic digestion of food waste. *Science of The Total Environment* **2020**, 724, 137977.
225. Van Houten, R. T.; Pol, L. W. H.; Lettinga, G., Biological sulphate reduction using gas-lift reactors fed with hydrogen and carbon dioxide as energy and carbon source. *Biotechnology and bioengineering* **1994**, 44, (5), 586-594.
226. Machel, H. G., Bacterial and thermochemical sulfate reduction in diagenetic settings—old and new insights. *Sedimentary Geology* **2001**, 140, (1-2), 143-175.
227. Jakobsen, R.; Postma, D., In situ rates of sulfate reduction in an aquifer (Rømø, Denmark) and implications for the reactivity of organic matter. *Geology* **1994**, 22, (12), 1101-1106.
228. Wan, J.; Peng, T.; Shen, R.; Jurado, M. J., Numerical model and program development of TWH salt cavern construction for UGS. *Journal of Petroleum Science and Engineering* **2019**, 179, 930-940.
229. Li, J.; Shi, X.; Yang, C.; Li, Y.; Wang, T.; Ma, H., Mathematical model of salt cavern leaching for gas storage in high-insoluble salt formations. *Scientific reports* **2018**, 8, (1), 1-12.
230. Boreham, C. J.; Edwards, D. S.; Czado, K.; Rollet, N.; Wang, L.; van der Wielen, S.; Champion, D.; Blewett, R.; Feitz, A.; Henson, P. A., Hydrogen in Australian natural gas: occurrences, sources and resources. *The APPEA Journal* **2021**, 61, (1), 163-191.
231. Warren, J. K., Solution mining and salt cavern usage. In *Evaporites*, Springer: 2016; pp 1303-1374.
232. da Costa, A. M.; Costa, P. V.; Miranda, A. C.; Goulart, M. B.; Udebhulu, O. D.; Ebecken, N. F.; Azevedo, R. C.; de Eston, S. M.; de Tomi, G.; Mendes, A. B., Experimental salt cavern in offshore ultra-deep water and well design evaluation for CO<sub>2</sub> abatement. *International Journal of Mining Science and Technology* **2019**, 29, (5), 641-656.
233. Chen, X.; Li, Y.; Liu, W.; Ma, H.; Ma, J.; Shi, X.; Yang, C., Study on sealing failure of wellbore in bedded salt cavern gas storage. *Rock Mechanics and Rock Engineering* **2019**, 52, (1), 215-228.
234. Berest, P.; Brouard, B.; Durup, J., Tightness tests in salt-cavern wells. *Oil & Gas Science and Technology* **2001**, 56, (5), 451-469.
235. Rouabhi, A.; Hévin, G.; Soubeyran, A.; Labaune, P.; Louvet, F., A multiphase multicomponent modeling approach of underground salt cavern storage. *Geomechanics for Energy and the Environment* **2017**, 12, 21-35.
236. Habibi, R., An investigation into design concepts, design methods and stability criteria of salt caverns. *Oil & Gas Science and Technology—Revue d'IFP Energies nouvelles* **2019**, 74, 14.
237. Zhang, Y.; Ma, H.; Shi, X.; Yin, H.; Zhang, S., Position design of the casing shoe of an abandoned horizontal salt cavern to be used for gas storage. *Energy Sources, Part A: Recovery, Utilization, and Environmental Effects* **2019**, 1-15.
238. DeVries, K. L.; Mellegard, K. D.; Callahan, G. D.; Goodman, W. M. *Cavern roof stability for natural gas storage in bedded salt*; RESPEC: 2005.
239. Goulart, M. B. R.; da Costa, P. V. M.; da Costa, A. M.; Miranda, A. C.; Mendes, A. B.; Ebecken, N. F.; Meneghini, J. R.; Nishimoto, K.; Assi, G. R., Technology readiness assessment of ultra-deep Salt caverns for carbon capture and storage in Brazil. *International Journal of Greenhouse Gas Control* **2020**, 99, 103083.
240. Wang, T.; Yang, C.; Ma, H.; Daemen, J.; Wu, H., Safety evaluation of gas storage caverns located close to a tectonic fault. *Journal of Natural Gas Science and Engineering* **2015**, 23, 281-293.
241. Hornyak, T. An \$11 trillion global hydrogen energy boom is coming. Here's what could trigger it. <https://www.cnn.com/2020/11/01/how-salt-caverns-may-trigger-11-trillion-hydrogen-energy-boom-.html>, Assessed on 28/02/2021
242. Forsberg, C., Assessment of nuclear-hydrogen synergies with renewable energy systems and coal liquefaction processes. *ORNL/TM-2006/114*, August **2006**.

- 1389 243. Ahluwalia, R.; Hua, T.; Peng, J.; Kumar, R., System level analysis of hydrogen storage options.  
1390 *Proceedings of the 2008 US DOE Hydrogen Program Annual Merit Review* **2013**.  
1391 244. Ziqiao, Z., Cementing techniques for wells with salt caverns used for gas storage in Jintan.  
1392 *Petroleum Drilling Techniques* **2006**, 34, (2), 45-47.  
1393 245. Energy, A. Australian Energy Update 2020  
1394 [https://www.energy.gov.au/sites/default/files/Australian%20Energy%20Statistics%202020%20Energy%20Update%20Report\\_0.pdf](https://www.energy.gov.au/sites/default/files/Australian%20Energy%20Statistics%202020%20Energy%20Update%20Report_0.pdf). Assessed on 3rd Sept, 2021  
1395  
1396 246. Andersson, J.; Grönkvist, S., Large-scale storage of hydrogen. *International journal of*  
1397 *hydrogen energy* **2019**, 44, (23), 11901-11919.

1398

1399

1400