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A technical review on underground hydrogen storage potential in porous media: A dynamic reservoir simulation approach

Stanley U. Opara, Chinedu J. Okere*

Bob L. Herd Department of Petroleum Engineering, Texas Tech University, TX, USA

Abstract

As the global demand for energy continues to climb and the urgency for carbon-neutral alternatives grows, hydrogen becomes increasingly prominent as a clean energy source[1], [2]. The research reviewed underground hydrogen storage potentials, discussing the distinction between the working gas and cushion gas that are critical in maintaining pressure and optimal injection conditions. Emphasis on the similarities between underground hydrogen storage and underground gas storage was made. Various underground hydrogen storage facilities were outlined, necessitating specific criteria for adaptability. Depleted hydrocarbon deposits emerge as prevalent storage systems for hydrogen due to their existing infrastructure for gas injection and retrieval, presenting a cost-efficient conversion for underground gas storage while other geological storage options include salt domes and aquifers [3], [4]. Selection criteria for sites or structures for underground hydrogen storage demand a thorough geological and engineering analyses, considering factors such as reservoir pressure, depth, permeability, and structural integrity and adaptability. Furthermore, the need to prevent hydrogen leakage and adhere to technical, economic, and safety considerations was underscored, particularly in managing fracture pressures within the reservoir during gas injection or withdrawal.

The research methodology involved developing a hypothetical reservoir model to evaluate the factors and parameters facilitating efficient hydrogen injection and withdrawal for large-scale storage. The Computer Modelling Group (CMG) reservoir simulation software was used in the research to simulate hydrogen storage and transport in porous media. Some of the model's input variables included parameters such as reservoir porosity, permeability, temperature, compressibility, and bottomhole pressure. Sensitivity runs were done on injection pressure, bottomhole pressure, permeability, and porosity to establish the significant properties that impacted hydrogen storage and the extent of their impact.

Keywords: Net zero carbon emissions; Climate change mitigation; Methane emission control; Abandoned oil and gas wells; Permian basin.

1.0 Introduction

An underground gas storage facility is an artificially created gas accumulation in the natural environment at a significant depth which could be several thousands of feet or more. Bunger et al., (2016) noted that several gas types are stored in these facilities which include – the working gas, which is the main gas that is injected and stored in the reservoir and withdrawn at a later period, the cushion gas is stored through the duration of the project's life and is responsible for exercising the minimum pressure required to prevent the inflow of water into the storage area and to enable optimum injection conditions [5]. There is a notable surge in global momentum for hydrogen as a future low-carbon energy carrier [6]. There are some similarities between underground hydrogen storage and underground natural gas storage or even underground storage of CO_2. The schematic underground hydrogen storage facility in Fig. 1 shows different underground hydrogen storage facilities including – aquifers, depleted hydrocarbon deposits, caverns mined in rock salt by dissolution underground mine workings and rock caverns. Specific conditions for each type need to be met for the first 3 storage facilities to make them to be adaptable for underground hydrogen storage. Underground mines pose a challenge due to tightness. For the aquifers and depleted hydrocarbon deposits, they are of pore-fracture type, where geological aspects and conditions are decisive for storage whereas technical aspects are of secondary importance. Depleted hydrocarbon deposits constitute the most common underground storage systems for hydrogen. Such deposits already have provision for installation for the injection and withdrawal of gas and processing systems that get the gas ready for transportation through transmission pipelines and other transmission systems. The conversion of depleted hydrocarbon systems for Underground gas storage (UGS) incurs the least cost amongst the other alternative UGS systems. Sainz-Gaska et al. (2012) stated that a functional UGS working efficiently ensures that the injected gas will be withdrawn in a significantly great amount without losses from the gas being escaped [7]. Underground hydrogen storage facilities have injection wells and production wells when the stored hydrogen gas is set to be used again as reported by many researchers.

When selecting sites for deposits or structure for UHS for hydrogen, it should be based on detailed geological analysis using the relevant engineering methods for underground deposits. Underground hydrogen storage (UHS) presents an appealing alternative in contrast to above-ground storage due to its reduced surface footprint and, consequently, lower overall cost [8]. As noted by Tarkowski (2019), some significant factors to be considered when making site selection for hydrogen UGS include – reservoir pressure, tightness, thickness, structure depth, reservoir permeability and porosity, geochemical properties, and characteristics of the insulating cap rock. It is necessary to ensure that that structural integrity of the geologic structure is maintained, and hydrogen leakage should be avoided. Technical, economic, government, commercial considerations must be adequately followed as expected. It is also important to take into consideration the fracture pressure of the reservoir and to ensure that it is not exceeded either during the injection or withdrawal of hydrogen gas from the reservoir [9]. Depleted gas reservoirs are well characterized with nearly all necessary information among the other underground geological structures [10]. When produced back to the surface, hydrogen can be used for electricity production, renewable energy sources, gas combustion units, etc. Hydrogen as a renewable energy source can be used as a form of electricity generation. For instance, Lemieux et al (2020) the Canadian government has identified the utilization of hydrogen gas produced through off-peak electrolysis as a prospective solution for effectively handling electrical grids facing surplus and intermittent electricity generation [11], [12], [13], [14], [15]. Another comparative advantage of hydrogen over fossil as noted by Sambo et al (2022) is that hydrogen, as a non-carbon-based energy source, holds the promise of being a potential substitute to fossil fuel use. It is considered an alternative fuel due to its potential for production through environmentally friendly methods [16]. Hydrogen presents the sought-after solution for decarbonizing industrial processes and sectors of the economy where achieving a reduction in carbon dioxide emissions is challenging [17], [18]. Jahanbakhsh et al (2024) noted that hydrogen is expected to have a pivotal role in the worldwide effort to reduce carbon emissions, including its significant contribution to the UK's journey toward reaching net-zero targets [19], [20]. Uliasz-Misiak et al (2021) observed that the incorporation of hydrogen as an energy carrier stands as a pivotal factor in realizing a carbon-neutral economy [21].

Research gaps have been identified by previous researchers in understanding uncertainties surrounding underground storage of hydrogen in porous media and predicting the appropriate petrophysical data necessary to minimize such uncertainties[22]. Al-Yaseri et al (2021) observed that so far a few studies have been conducted on hydrogen-clay interactions with most of them concentrating on hydrogen adsorption on clays [23]. Another group of researchers established the necessity of numerical simulation for understanding the dynamics surrounding hydrogen storage in depleted reservoirs and further stating its usefulness in determining the optimal conditions for maximizing hydrogen withdrawal from underground hydrogen storage sites. The researchers pointed out the need for additional investigation required to replicate thorough sensitivity analyses under standard saline reservoir conditions. This is necessary to establish the criteria for selecting potential saline reservoirs for hydrogen storage. [24]. Kowalski (2021) noted that Significant work has been undertaken to assess Rules, Codes, and Standards (RCS) pertaining to the emerging fuel cell industry, including the necessary infrastructure to facilitate fuel cell electric vehicles or small-scale hydrogen storage. Nevertheless, there is currently no comparable procedure in place for reviewing and developing Rules, Codes, and Standards (RCS) specifically tailored for the large-scale storage of hydrogen. [25].

One of the objectives of this research entails understanding the various underground hydrogen storage systems and the conditions that necessitate the choice of storage in depleted petroleum reservoirs. A second objective is to conduct a field analysis of hydrogen storage project using a numerical simulation approach which was used to model the key parameters that impact underground hydrogen injection, storage, and withdrawal. The results from sensitivity analysis on the key parameters that influence hydrogen storage were further analyzed to determine their degree of influence on hydrogen injection and withdrawal.

1.1 Advantages of underground gas storage facilities

Clemens et al (2022) stated that storing hydrogen seasonally is facilitated by utilizing depleted gas and oil reservoirs or aquifers, as they can accommodate the significant volumes of hydrogen that require storage [26]. Hydrogen is emerging as a substitute for traditional energy sources because it produces no Greenhouse Gas (GHG) emissions when utilized [27], [28]. Storage of hydrogen in large scale can help alleviate the main drawbacks of renewable energy generation, their intermittency and their seasonal and geographical limitations and challenges [29].

Some advantages of underground gas storage facilities as recorded in literature include:

- Storage safety – whereby underground storage makes the CO_2 or hydrogen gas to be less susceptible to risks from fire, wars, military actions, etc.
- Economic benefits – the cost of constructing surface storage facilities is higher than that of underground storage facilities.
- Space utilization – Surface storage facilities such as surface tanks would occupy more space than underground storage facilities for storing the same amount of gas [30].
- There is a wide availability of suitable geological structures which are common in many countries.

1.2 Developments in the discovery of underground gas storage facilities

Tarkowski (2019) noted that the number and capacity of underground gas (UGS) storage facilities have significantly increased in the last century, stating that 642 underground gas storage sites were exploited globally as of January 2010. Most of the UGS sites are situated in depleted hydrocarbon deposits (~476), others like aquifers (~82), and salt caverns (~76) (Gaska 2012). Depleted hydrocarbon reservoirs are the most common geological structures that are being used for gas storage facilities. Salt caverns have recently increased in their use as UGS sites.

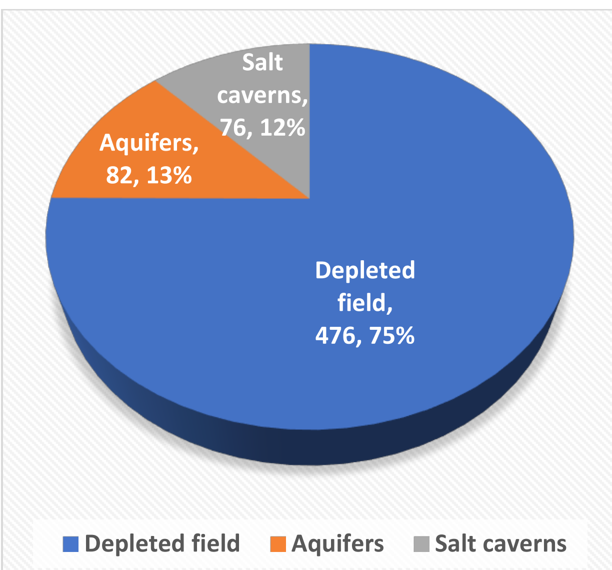

Fig. 1: Share of worldwide UGS by storage type in 2020 (Sainz-Gaska et al., 2012) [7]

According to the International Association Dedicated to Natural Gas Information (CEDIGAZ) in the year 2010, about ~82 salt caverns were among the 202 planned new and expanded currently existing UGS sites globally. CEDIGAZ further noted that 680 UGS facilities were in operation globally as at the end of year 2015. This number of UGS sites represented working gas capacity of 413 bcm (14585 bcf) which were mainly located in in three regions with developed gas markets including – North America (38%), Commonwealth of Independent States (CIS) (29%), Europe (27%), Asia/Oceania (4%), Middle East (2%) of the global Underground Hydrogen Capacity. Tarkowski (2019) stated that the working gas capacity by the type of UGS facility is distributed as thus – depleted fields (80%), aquifers (12%), salt caverns (8%). The working gas capacity for the European Union (EU) was 110 bcm (3881.6bcf), comprising – depleted fields (68%), aquifers (15%) and salt caverns (17%) as stated by the researchers.

Zamehrian et al (2022) suggested that the potential to store substantial volumes of hydrogen within varied geological structures has heightened the fascination with underground hydrogen storage. They suggested several appropriate geological structures for hydrogen storage, including salt caverns, aquifers, and depleted oil and gas reservoirs [31], [32]. The storage of hydrogen in salt caverns serves as a form of large-scale energy storage; however, it requires geology that is both suitable and safe. According to Hematpur et al (2023), the primary stages involved in the formation of salt caverns include leaching, debrining, and filling [33]. To create a cavity within the salt, a process called leaching involves injecting freshwater into the salt domes. Subsequently, once the brine has been extracted, the salt cavern becomes prepared for the storage procedure. A depleted hydrocarbon reservoir is another viable choice for underground hydrogen storage (UHS), given the effect of reservoir characteristics acquired during the exploration and development stages of hydrocarbon reservoirs [31]. Significant quantities of hydrogen can be stored in depleted oil and gas fields, salt caverns, and aquifers [34], [35], [36].

Amirthan et al (2022) observed that depleted reservoirs stand out as a significant choice for Underground Hydrogen Storage (UHS) because of their demonstrated success in securely trapping oil and gas for extended periods and their comparative abundance when contrasted with other structures [37]. Hydrogen storage has been noted to be more favorable in gas reservoirs than in oil reservoirs which arises from the potential for a significant loss of hydrogen through dissolution in oil reservoirs [9]. Additionally, in depleted gas reservoirs, there exists residual native gas that can serve the purpose of cushion gas[30]. Another geological structure for the storage of underground hydrogen is aquifers. The potential for underground hydrogen storage (UHS) in an aquifer anticline structure was appraised in Poland. No instances of viscous fingering were detected, and the near-wellbore area displayed the highest hydrogen saturation [7].

Table 1: Existing Hydrogen Caverns in the US – (HyUnder – Grant No. 303417)

	Clemens (USA)	Moss Bluff (USA)
Geology	Domal salt	Domal salt
Stored Fluid	Hydrogen	Hydrogen
Commissioned period (years)	1983	2007
Capacity (ft^3)	20,482508	19,988103
Reference Depth (ft)	3051	> 2696
Pressure range (bar)	70 — 135	55 — 152

Bai et al., (2015) and Bunger et al. (2016) summarized important geological, technical, and environmental aspects of the various options of underground hydrogen storage in aquifers and depleted hydrocarbon deposits based on information from available literature on geological and engineering aspects of underground gas storage as shown in Table 2 [5], [38].

Table 2: Geological, technical aspects of different underground hydrogen storage systems (Tarkowski, 2019).

Parameters	Deep aquifers	Depleted oil and gas fields	Salt caverns
Occurrence	Common in all sedimentary basins	Traps accumulating hydrocarbons	Common in many sedimentary basins

Depth of deposits	Various depths, optimally up to 2000m (6562ft)	Various depths, optimally up to 2000m (6562ft)	Various depths, optimally up to 1500m (4921ft)
Lithology of site storage and caprock	Reservoir rock with high porosity and high permeability, roof rocks providing seal, not cracked	Reservoirs with high permeability and high porosity, roof rocks providing seal, not cracked	Thick salt deposits: salt beds seem most appropriate
Storage capacity	Very high	Very high, and close to the quantity of exploited gas	High, and corresponds to the volume of a cavern or a group of caverns.
Geological tightness	The tightness of aquifer initially unknown, a low risk of gas leakage	The existence of gas deposits confirms their tightness	The tightness is assured by favorable properties of the salt rock
Required research	Possible leakage paths. Chemical, mineralogical and biological reactivity between hydrogen and rock formation and its sealing overburden; tightness of caprocks for hydrogen permeation. Monitoring of the tightness and controlling of reservoir pressure.	Monitoring tightness and controlling reservoir pressure. Chemical, mineralogical, and biological reactivity between hydrogen and reservoir rocks and its sealing overburden; tightness of caprock for hydrogen permeation.	Geophysical surveys of salt caverns during cavern leaching. Periodic surveys of changes in the cavern during operation.

Limitations	Adaptation of existing boreholes for hydrogen storage may not be feasible. The availability of suitable technology and equipment for the construction and operation of storage systems.	Adaptation of existing boreholes may not be feasible. The availability of suitable technology and equipment for the construction and operation of the storage system. Reactivity of hydrogen with liquid hydrocarbons limiting the usefulness of depleted oil fields.	Convergence caused clamping for the cavern. The availability of suitable technology and equipment for the construction and operation of the storage system. The availability of water for cavern leaching.

1.3 The need for hydrogen as an energy source

The global demand for energy shift from fossil is gradually making alternative energy sources like hydrogen energy gain more popularity in recent times. However, large scale utilization of hydrogen energy is partly limited by the challenges faced with the storage of hydrogen gas. Wang et al., (2023) stated that hydrogen gas been excessively active and reactive means that it could damage the storage containers which are usually made of metal caused by what is known as hydrogen embrittlement effect [39]. They noted that during hydrogen embrittlement, the metal material gradually becomes brittle and develops cracks, leading to failure of the metal material. This challenge has prompted the demand for a more efficient and safe method to store hydrogen gas such as underground storage of hydrogen [39]. Depleted oil and gas wells could serve as good candidates for underground storage due to the availability of the pore spaces that were previously occupied by the produced oil and gas. The process follows a cyclic injection of hydrogen which is later produced after some time. The working process for the subsurface storage of hydrogen involves an initial step whereby cushion gas (CG) is injected into the depleted reservoir for the reservoir's pressure maintenance and buildup of the depleted reservoir that would be used for hydrogen storage. After the reservoir has attained an equilibrium pressure, working gas (WG) is injected and produced in cycles. It is important to factor in the changes in bottom hole pressure (BHP) while injecting the gas as the amount of the nitrogen gas injected is constrained by the upper limit of the BHP that is usually determined by the fracture gradient of the formation [39], [40]. It was also noted that the lower limit of the BHP is usually theoretically determined by the rock's failure criteria. The cushion gas is not meant to be produced during the cycling process. The lower limit of the BHP of the storage site is usually the initial (or base) pressure to avoid producing back the cushion gas (CG) to the surface. To ensure that the fractures are kept open, the difference between the upper pressure limit and the lower pressure limit should not be significantly high apart. It is projected that in the future, the demand for hydrogen is likely to outpace current production and transport technologies [41], [42]. Raza et al (2022) noted that hydrogen from electrolysis of renewable sources is thus referred to as green hydrogen which holds crucial significance to decarbonization [43]. A significant advantage of hydrogen is that hydrogen (H2) exhibits environmentally friendly (clean) combustion and remarkable versatility, serving purposes ranging from electricity and heat generation to being utilized as a fuel in transportation and energy storage [44].

Pan et al (2021) observed that underground hydrogen storage has been identified as a promising advancement in technology which ensures storage of hydrogen in economic scale [45]. The utilization of underground hydrogen storage technology ensures that significant amount of hydrogen gas (H_2) is effectively and safely stored in geological formations such as empty salt caverns, deep aquifers, depleted oil and gas reservoirs, underground coal seams etc. Pan et al (2023) noted that storage time for the underground hydrogen storage can range from months to years depending on current energy demand for the hydrogen at the time [45]. As noted by a previous researcher, salt caverns have been demonstrated to be feasible as underground hydrogen sources. Furthermore, it has been stated that underground hydrogen storage such as those in depleted oil and gas reservoirs, deep aquifers and coal seams are still under investigative research [9]. These sedimentary reservoirs are quite abundant and widespread geographically and remain a potential storage site for hydrogen gas storage.

A key parameter for assessing the feasibility of such behavior of sedimentary reservoirs for underground hydrogen storage candidate is the behavior of hydrogen in the pore network of the reservoir rock at reservoir pressure and temperature conditions [45]. The multiphase reservoir fluid dynamics associated with this process is determined by the observed pore scale effects. It was noted that hydrogen gas and formation brine can coexist and flow simultaneously in the pore space in the case of salt caverns since brine is always present in salt cavern formations [45], [46]. Major determinant factors like containment security, storage capacity and potential hydrogen injection and withdrawal rates are determined by such pore-scale effects.

1.4 Hydrogen storage in subsurface porous media

Heinemann et al. (2018) stated that the concept of hydrogen storage in subsurface porous media is made up of different steps such as injection and withdrawal of the hydrogen in question. In their study, they assumed that the hydrogen was injected into a porous and permeable reservoir formation by means of injection wells. The injected hydrogen was meant to displace the original pore fluid i.e., usually brine and subsequently flows out underneath an impermeable seal because of its lower density. Trap and seal structures will prevent the hydrogen from migrating. The stored hydrogen can then be produced whenever the need arises, and the hydrogen will be produced from production wells directly from the reservoirs [47]. A cushion gas which is otherwise described as a portion of the hydrogen gas that will be left in the reservoir as a precautionary measure to maintain the reservoir system pressure during the withdrawal period of the hydrogen gas and to reduce the occurrence of subsurface water encroachment from the porous media into the hydrogen storage reservoir. Some portions of hydrogen will remain in the pores due to residual trapping and it was noted that the success of hydrogen recovery significantly depends on the expansion of the gaseous phase in the storage sand one [48], [49], [50]. The effect of residual trapping is such that there are tiny, isolated bubbles of the hydrogen gas which cannot be produced but rather will remain in the pores, hence making it impossible to reproduce back the entire hydrogen gas that was injected originally into the reservoir. As noted by Le Fevre (2013), about 55% of the injected hydrogen gas will not be produced back to the surface based on estimates from natural gas storage in saline aquifers. It was further noted that the total hydrogen lost from the combined cushion gas and residual trapping effects occur during the first injection and withdrawal cycle [51]. Zhenkai Bo (2020) stated that hydrogen loss during the various stages of injection and production cycle is a key factor that required a thorough examination and control in order to assess the feasibility of the underground hydrogen injection project [52].

1.5 Hydrogen storage plays

Heinemann et al. (2018) noted that the term petroleum play is a model of how a producible reservoir charge system, regional traps and top seal could be combined to produce petroleum accumulations at a specific stratigraphic level [47]. Bennion et al (2000) has noted that to be a candidate for gas storage there must be sufficient volume of pore space in the reservoir to allow storage without exceeding containment pressure or having a need for compression obtained from sealing formations [53]. Also observed was that for such candidate reservoirs, there should be sufficient permeability to allow for injection and withdrawal of the hydrogen gas at the required rate and limited response to permeability reduction. Some other important requirements include sufficient reservoir volume, permeability, and porosity. A trap as well as a regional seal is necessary to allow hydrogen to accumulate and ensure that the hydrogen is safely stored for the specific period that it was intended to be stored for and a specified stratigraphic level. The major type of the candidate reservoir in question are sedimentary rocks like sandstones and limestones. An impermeable seal layer or seal is meant to overlay the reservoir to trap a buoyant fluid like hydrogen. The reservoir and seal successions have been observed to accumulate in many various depositional environments across geological timescales. A trap reinforces the seal to prevent the stored hydrogen from leaking laterally within the succession layers [47], [54]. The traps could be sedimentary traps of lateral thickness such as a sedimentary pinchout that is formed during the depositional period. As noted, hydrogen storage plays are simpler than hydrocarbon plays since the hydrocarbon plays require more complexity of organic matter within the source rock that can generate oil or gas within a specified geological period in question to allow for the fluid migration into a trap inside the original sealing and trapping system of the reservoir. As observed by Heinemann et al (2018), hydrogen storage sites are usually more obtainable within the subsurface. Just like the case of petroleum plays, hydrogen storage plays require geological models that ought to be better history-matched and calibrated both with the field and lab data in addition to further research and development [47]. Tarkowski et al (2018) stated that underground geological space is suitable for storage of energy in the form of hydrogen [55], [56].

1.6 Challenges with underground hydrogen storage in porous formations

Okoroafor et al. (2022) summarized some challenges identified by previous authors on underground storage of hydrogen in porous formations [22], [57], while noting that Foh S. (1979)

conducted a wide range of studies on the technical and economic visibility of the storage of hydrogen gas in underground reservoirs such as depleted oil field, salt cavern, excavated rock cavern aquifer, etc. [58]. In their studies, analytical models were used to represent the volume of hydrogen stored at any given pressure and temperature, the flow rate of the storage hydrogen gas, and the water motion response to hydrogen withdrawal. In their studies, they demonstrated that there were no technical limitations to underground storage of hydrogen in porous media [58]. Despite the finding by the authors, it was observed that the experience with underground storage of hydrogen in porous geological formations is constrained by practical applications to the storage of hydrogen gas with smaller composition of methane and nitrogen. Several authors have investigated the challenges with hydrogen storage in the subsurface and their findings identified loss of hydrogen from the effect of microbial growth in the reservoir, interaction (or mixture) of hydrogen with the reservoir, geochemical reactions of the hydrogen gas within the reservoir, mixture of hydrogen with the cushion gas, etc. (Heinemann et al 2021; Pan B et al 2021) [45], [59]. Some other authors observed that uncontrolled lateral spreading of hydrogen, leakage of hydrogen through the faults running the reservoir or leakage directly from the caprock, cyclical stress fluctuations and clay swelling induced stresses are key factors when making the choice of storage sites for hydrogen storage as noted by Heinemann et al. (2021) and Osman et al. (2021) [59], [60], [61]. A key approach to address some of the associated challenges of storage of hydrogen is by carrying out numerical simulation studies which gives the opportunity of modelling the complex physics to capture the behavior of underground hydrogen storage in porous geological formations. The assessment of the integrity of a well in a underground hydrogen storage program necessitates additional examination of the effects of hydrogen on steel materials. This includes primarily hydrogen blistering, hydrogen-induced cracking, and hydrogen embrittlement [62].

1.7 Impact of reservoir depths and pressure on productivity index (PI)

In the result present by Foh S. et al. (1979), compression cost was identified to be the significant contributor to the overall cost of underground hydrogen storage projects. It is necessary to optimize the compression cost arising due to the amount of compression energy required as well as maximizing the productivity index (PI) of hydrogen [58]. Okoroafor et al. (2022) in their work where that the (PI) and compression energy estimated for different depths, they observed that compression energy increased as the reservoir pressure increased. They emphasized that for a depleted gas field, the depth was not a factor that drives the (PI) and the compression energy that was required but rather noted that the pressure in the depleted fields was a function of the volume of fluid produced and production approach that was used. Pressure was noted to be a significant factor that drives the (PI) and compression energy required for storage of hydrogen gas in depleted fields. Additionally, it was noted that for non-depleted oil and gas reservoirs and saline reservoirs, the static reservoir pressures were not impacted by fluid withdrawal and hence the depth correlates with the pressure in a normal pressure regime. The depth can be used as a site selection criterion in such a situation [24].

As reported by the authors (Okoroafor et al., 2022), Fig. 3 shows a plot of productivity index (PI) which decreases with increasing pressure and depth. Also shown in the plot is compression energy which increases with increased pressure and depth. A maximum depth of 3000m (9843ft) for storing hydrogen was proposed by the authors considering the increased compression energy and reduced productivity index with depth. The minimum PI was set at reservoir pressure not lower than 32 bar (464psi) basing their simulation on withdrawal well bottomhole pressure limit of 30 bar (435psi). The following suggestions were made by the authors[24]:

- The tubing head pressure, wellhead pressure or surface facilities' pressure should be used as the constraint to determine the minimum reservoir pressure for geological storage of hydrogen in depleted gas fields.
- From the wellbore pressure losses, if the reservoir pressure was known, the wellhead pressure could be estimated by subtracting 1 bar/100m (14.7psi/328ft) from the reservoir pressure to know if the reservoir pressure would meet the surface pressure constraints.

1.8 Parameters impacting underground hydrogen storage in porous media

Okoroafor et al., (2022) showed results of their sensitivity on parameters that affected hydrogen storage according to the level of their significance [24]. Understanding underground hydrogen storage involves knowledge of the physical characteristics of hydrogen, including density, viscosity, and solubility, which have undergone thorough investigation [63].

1.8.1 Absolute permeability

The results as shown in the Tornado plot in Fig. 4 showed that increasing the permeability by 50% resulted in a 20% increase in productivity index of hydrogen whereas reducing the permeability by 50% resulted in a 40% reduction in productivity index of hydrogen [24]. A general trend that was established by the researchers indicates that increased absolute reservoir permeabilities improve hydrogen recovery. It was further noted that below 100mD, the productivity index (PI) dropped below 500 m^3/day/bar (20.14 ft^3/day/psi) which was more than thrice the productivity index of their base case which had permeability of 500mD.

1.8.2 Reservoir thickness

From their Tornado plot (in Fig. 4), it was reported that either increasing or reducing the reservoir thickness will result in a reduction in the productivity index (PI) in comparison to the base case PI. In their model, they evaluated the impact of reservoir thickness to the PI using three different reservoir thickness values – 10m, 20m, and 200m. Two scenarios were deployed; the first scenario involved the reservoir thickness being opened to flow to about 30%; the reservoir was completely opened to flow in the second scenario. In the first scenario, the optimal depth was attained at 110m while in the second scenario the optimal depth was attained at 50m as reported by the authors. There was a noticeable decline in additional PI after the optimal reservoir thickness had been attained.

1.8.3 Impact of reservoir dip on hydrogen productivity

The result as reported by the authors showed that a dipping reservoir placed with an injector or withdrawal well up-dip gave a good response for hydrogen productivity and recovery. From results from their model analysis, they noted that reservoirs with permeability below 100mD did not significantly improve in their recovery when their reservoir dip angles were increased. High permeability reservoirs however were reported to have increased hydrogen productivity with an increase in dip.

1.8.4 Permeability anisotropy

Sensitivity anisotropy ratio (K_v/K_h) of 0.1 was used by the authors in their base model. After performing sensitivity analyses with different values of K_v/K_h for different absolute permeability values, they reported that the permeability anisotropy ratio was not a sensitive parameter. When the K_v/K_h was greater than 0.5, a minimal impact was reported for hydrogen productivity index (PI) while for K_v/K_h ratios below 0.5, there was increase in hydrogen PI.

1.8.5 Withdrawal rates

The authors examined the impact of different gas withdrawal rates on hydrogen PI and the hydrogen purity was estimated by the third injection and withdrawal cycle. The drawdown increases with increasing withdrawal rates hence this results in their lower productivity index values. The hydrogen purity consistently reduced as the rate increased.

1.8.6 Hydrogen propagation and final distribution

The authors noted that hydrogen flow patterns were largely determined by local permeability and presence of partially sealing fault blocks whereby high permeability regions had high hydrogen flow [64]. Minor viscous fingers were noticed in the water zone but were completely absent in the oil zone. Some previous authors have already opined that the lack of fingers was due to structural geometries, stating that the steeply dipping structures limited the development of fingers. Lysyy et al. (2021) in their work, had hydrogen injected in the planar structure, without development of pronounced viscous structures. They opined that the absence of viscous fingers was due to modelling rather than geologic structure geometry. From their model results, vertical hydrogen flows were observed despite lower permeability layers that hindered downwards (around the gas zone) and upwards (around the water zone) with hydrogen displacement from the onset of injection. It was observed that gravitational effects did not have any significant influence in the thin gas zone. Due to the presence of fault blocks in their model, there was bypassing of discontinuous lower permeability layers (within the oil zone) and enabling of vertical hydrogen migration along the boundary between fault blocks (within the water zone). It was noticed in the oil zone that simultaneous vertical and horizontal hydrogen migration in the near-well area occurred from a combination of two factors. First, the thicker oil zone provided access to the adjacent high permeability grid layers while for the second case, the hydrogen saturations were lower because of the presence of oil and water. They observed that the maximum hydrogen saturation and downward migration were achieved faster in the oil zone compared to the gas zone. They noticed that upward hydrogen migration was delayed due to high water saturation (> 80%) in the overlying low permeability layer but occurred in the far well area where water saturation was significantly reduced (to 60%). While moving upwards, it was observed that hydrogen accumulates below the low permeable barriers and at the top of the reservoir where it spread laterally.

1.9 Some underground hydrogen storage project sites

1.9.1 Salt Caverns:

As reported by Sambo et al., (2022) hydrogen storage of about 95% purity in salt caverns globally is limited to four projects across the world which are situated in the U.S. and U.K. with the U.S. hosting three site locations while U.K. hosts one site location [65]. The researchers noted that there had been no reported issues in literature of biological or chemical degradation of the stored hydrogen in those salt caverns. It was reported that the European countries have made more efforts to promote hydrogen storage in salt caverns (Cyran & Kowalski, 2021)[25]. Lankof et al (2020) noted that the size of a salt cavern is dependent on its shape and dimensions because of the varying rock salt layer thickness [17], [66]. Identifying appropriate storage sites for UHS involves a complex decision-making process with multiple criteria. The initial step in tackling this challenge is to clearly define the decision problem, including its objectives, selection criteria, and alternatives for decision-making [67].

1.9.1.1 Clemens (Salt) Dome Texas USA

Sambo et al., (2022) noted that Conoco-Philips has stored 95% purity hydrogen in the Clemmons salt dome near Lake Jackson in Texas since around 1983 [65]. They stated that the salt dome has a capacity of approximately 580000 m^3 with depths between 850m — 1150m. The cavern structure is like a cylindrical shape with diameter and height of 49m and 300m respectively. The total capacity of usable hydrogen was reported to be 30million m^3 or 2520 metric tons while the pressure range was between 70 bar to 135 bar during the operation. Detailed storage capacities of the cavern for the various gas components as compiled are presented in Table 3 below [65].

1.9.1.2 Moss Bluff, Texas USA

Linde Plc as reported by Warnecke et al., (2021) has stored 95% purity hydrogen in the Moss Bluff salt dome located in the Northeast area of Houston, Texas since 2007. The capacity of the salt cavern was reported to be around 566000m^3 with a depth range of 820 — 1400m. The cavern has a mean diameter of about 60m with a height of 580m and pressure ranges between 55 bar to 152 bar during operation [68].

1.9.1.3 Spindletop, Texas USA

Run by a company named Air Liquide, the Spindletop has been reported as the world's largest hydrogen storage facility. It is an underground cavern in the Spindletop salt dome domiciled in the Gulf Coast region, around Beaumont, Texas (Warnecke et al., 2021) [68]. The salt cavern is situated at a mean depth and mean diameter of ~1500m and ~70m respectively. The storage capacity is ~906000m^3 while the pressure ranges between 68 — 202 bar during operation. The storage capacities of the cavern for the various gas components have been reported in the Table below.

1.9.1.4 Teesside, Yorkshire (UK)

A British company named Imperial Chemical Industries (ICI) is reported to have since 1972 stored ~1million m^3 of pure hydrogen in the salt caverns within the Teesside, Yorkshire area. There are three salt caverns lying at the depth of ~380m in the deep Permian bedded salt deposits reported to be storing pure hydrogen (95% H_2 and 3—4% CO_2) at Teesside in Yorkshire with each of the three caverns having a volume of ~70000 m^3 and a total storage size of ~210000m^3. Sambo et al., (2022) stated that a different company named Sabic Petrochemicals operates an underground storage facility from where the stored hydrogen is directly used in a nearby refinery (Liebscher et al., 2016). Cushion gas was not required nor used because the caverns operated at a constant pressure of ~45 bar. The working gas capacity was reported to be about 8.9 x 10^6 m^3 which was about the same volume as the entire hydrogen gas volume [65].

Table 3: Summarized information on salt cavern sites for hydrogen storage globally (Sambo et al., 2022) [65]

		Salt Caverns			
		Teesside (UK)	Clemens (USA)	Moss Bluff (USA)	Spindletop (USA)
Storage Parameters	Geology	Bedded salt	Domal salt	Domal salt	Domal salt
	Operators	Stanbic Petrochemicals	Conoco-Philips	Linde plc	Air Liquide USA

	Stored fluid (% H_2)	95%	95%	95%	95%
	Year commissioned	1972	1983	2007	2017
	Geometrical Volume (m^3)	210000	580000	566000	906000
	Reference depth (m)	380	850 —1150	820—1400	1500
	Pressure range (bar)	46	70—135	55—152	68—202
Storage Capabilities	Cushion gas (106 kg of H_2)	0	2.21	2.3	N/A
	Working gas (106 kg of H_2)	0.76	4	3.72	8.23
	Cushion gas (GWh)	0	87.1	90.6	N/A
	Working gas (GWh)	29.9	157.4	146.7	274
Status	Operating	YES	YES	YES	YES

1.9.1.5 Kiel, Germany

Berest et al., (2012) noted that at Kiel, town gas of 60—65% hydrogen quality has been stored in a salt cavern with a geometric volume of 32000m^3 at a depth ranging between 1305m—1400m and operating pressure range between 80bar to 160 bar since 1971 [65]. Out of the total 68000m^3 salt cavern, less than 60% of this value was available for storage due to high insoluble content from the leaching process when the caverns were created [69].

1.9.2 Aquifers:

1.9.2.1 Beynes, ile de France

The site was operated by gas de France (GDF) from 1956 to 1974 and was the largest developed underground storage facility in France. Beynes site is in the Paris basin – the largest sedimentary basin in France. The basin has several anticlinal structures and aquifer reservoirs which makes it suitable for gas storage. In Beynes, natural gas and town gas with 50% H_2 were reported to be stored in an aquifer with a capacity of 3.3×10^8 m^3 at a depth of 430m. Tarkowski (2019) reported that for 18 years of operation there had been no issue from gas losses, or changes in gas composition except that there was a lot of bacterial activities and change in gas composition [9].

1.9.3 Depleted oil and gas reservoirs:

1.9.3.1 Diadema field, Argentina

The Diadema project was launched in 2001 and it became Argentina's first ever underground gas project which also focused on supporting some of the cities that faced low natural gas supply due to insufficient storage space. In terms of structure, the Diadema field is reported to be divided into blocks by a direct fault with an East-West and Northeast-Southwest strike. Rodriguez et al., (2001) noted that although recent studies focused on hydrogen storage, which was pilot tested in the Glauconitic sandstone reservoir there have also been some insights on natural gas storage in the Banco Verde depleted gas reservoir all located within the Diadema field [70].

1.10 Deductions from previous numerical simulation studies

Pfeiffer et al. (2015) understudied the behavior of hydrogen during underground storage in porous media by using a numerical simulation approach with ECLIPSE 300 reservoir simulation software while using nitrogen as the cushion gas. In their model build up, the hydrogen gases were modeled as first-contact miscible using the equation of state of Peng Robinson. The findings from their studies showed that the rate of hydrogen withdrawal from the underground storage reservoir increased as the number of storage cycles increased while the amount of water extracted from the storage reservoirs declined as the number of cycles increased [71].

Lysyy et al. (2021) using a similar numerical approach with ECLIPSE 100 reservoir simulation with a software conducted numerical simulation of cyclic hydrogen storage where they treated hydrogen as a solvent as a multiple-contact miscibility (MCM) fluid using the Norne field, located offshore of Norway [64]. They evaluated three distinct storage models by injecting hydrogen into the oil, gas, and water zones. They deployed four annual withdrawal-injection cycles that was immediately followed by one long withdrawal period. In their findings they observed that the thin gas zone has the highest performance with a recovery factor of 87%. It was also observed from their studies that a lower storage efficiency was obtained when the injector well was placed lower in the dipping structure.

The cushion gas selected may affect the recovery and quality of hydrogen recovered from underground hydrogen storage as noted by Wang et al. (2022) [39]. They evaluated the impact of using CO_2 as a cushion gas to observe hydrogen flow in a depleted heterogenous aquifer system in the subsurface using a scalable 2-dimensional simulation model. They observed that hydrogen infiltrates the cushion gas within the surrounding area to the injector wells thereby distorting an effective piston-like displacement of the CO_2. They observed that the recovery performance of hydrogen was less in high viscous flow regimes while the best recovery performance occurred in high gravity regimes. Kanaani et al. (2022) used the numerical simulation model from an oilfield composed of heavy crude oil in a heterogeneous carbonate reservoir rock to evaluate the influence of methane, nitrogen, and CO_2 when used as cushion gas for underground storage of hydrogen in the depleted oil reservoir. In their findings, they observed that methane showed the highest performance for choice of cushion gas before nitrogen and CO_2 [72].

Zamehrian et al. (2022) studied the influence of cushion gas on underground hydrogen storage in a partially depleted gas condensate reservoir using numerical simulation model mimicking the gas condensate field that has been depleted. They noted that given the limited experience in underground hydrogen storage, expertise and understanding of underground gas storage (UGS) can be applied to the processes of underground hydrogen storage [31]. Typically, within the underground storage process, gas inventory consists of two primary types: working gas and cushion gas. While the working gas is utilized based on demand, the cushion gas remains within the reservoir throughout the storage period, ensuring pressure maintenance and supporting deliverability. They noted that cushion gas composition can be the same as working gas or different [31]. The cushion gases considered in their study were CO_2, methane, and nitrogen gases. The highest and uncontaminated hydrogen recovery were obtained through the injection of nitrogen while the lowest hydrogen recovery and least pure hydrogen recovery were obtained by the injection of CO_2 as the cushion gas [31].

Hagemann et al. (2015) studied the effects of hydrodynamics, gas rising and lateral spreading for underground storage of hydrogen gas [73]. The gas phase viscosity was calculated using the Wilke's method while the gas phase density was calculated using the ideal gas law. They observed that gravitational forces were dominant at small injection rates. The dominant gravitational force supported uniform displacement of water. Conversely, at greater injection rates, viscous forces become dominant at increased injection rates which creates an unstable condition in water displacement, and gas fingering propagates below the caprock by the adjacent boundaries of the reservoir.

Feldmann et al. (2016) in their study tried to understand the hydrodynamics of underground hydrogen storage, gas mixing, seasonal injection, and production cycles. Using ideal gas law, they calculated the gas-phase density while the Wilke method was used to calculate the gas-phase viscosity. From their findings, it was observed that viscous fingering and gravity override have a minimal impact in the displacement of the original fluid if the reservoir is gas saturated. An average hydrogen concentration of 82 mole% of the extracted gas in the depth for the first production cycle and this Fig. further increased to 85.2 mole% by the last production cycle [74]. Tarkowski et al (2022) noted that recently, the United States has been producing approximately 10 million tons of hydrogen annually. The majority, roughly 6 million tons, is employed in the petrochemical industry (specifically, oil refining) and the manufacture of ammonia, accounting for about 3 million tons per year. Additionally, the production of biofuels and synfuels utilizes 1 million tons of hydrogen [75].

Amid et al. (2016) using a geochemical modelling approach investigated the chemical stability and potential losses associated with the chemical interaction of the constituent fluids in the reservoir. Their findings opined that the loss of hydrogen arising from diffusion and dissolution in the reservoir system were less than 0.1% [76]. Further results showed that the amount of hydrogen that was lost due to conversion to methane and biomass through the lifespan of the underground storage scheme was not more than 3.7%. It was observed by Hagemann et al. (2016) that lateral fingers were more prevalent in underground hydrogen storage than it was in natural gas storage systems [73].

Sainz-Garcia et al. (2017) evaluated the strategies for underground storage of hydrogen in a seasonal sequence in a saline aquifer using a multiphase software called COMSOL. They evaluated the gas phase density with the use of the Peng-Robinson state. In their model, the water hydrodynamic properties and the gas viscosity were calculated with the CAMSOL equation of state which was a built-in function in the model. From their findings, their study showed that as much as 78% hydrogen roundtrip recovery can be achieved [7]. It was observed that highly dipping reservoirs which could store hydrogen without requiring cushion gas although such reservoirs were prone to water cresting. It was further observed that hydrogen recovery improved by using extraction wells perforated slightly below the caprock and completed within the reservoir thickness [7].

Lubon et al. (2020) used a compositional numerical simulator to determine the viability of seasonal hydrogen storage in a deep aquifer. In their results, it was demonstrated that it was around the injection well where the maximum saturation with hydrogen occurs and that the hydrogen flows towards the top of the reservoir that does not extend above the top of the caprock [77]. The authors evaluated the influence of caprock availability and the recovery rate of hydrogen from a porous heterogeneous reservoir. In their findings, they discovered that hydrogen leakage without a caprock is increased by high injection rate. It was also noted that caprock availability and lower injection rates improve the amount of hydrogen that is recovered. Additionally, it was observed that heterogeneity in sedimentary reservoir rocks arise from both their initial deposition conditions and the diagenetic processes occurring during consolidation [78], [79].

Heinemann et al. (2018) carried out a sensitivity analysis geared towards understanding the impact of storage parameters on the capacity to store hydrogen. From their studies they showed that irreducible water saturation, reservoir pressure and the working gas capacity fraction were the most significant factors that impacted the storage capacity. It was observed that the working gas capacity fraction increased as the reservoir pressure was increased while the amount of hydrogen that could be stored increased as the irreducible water saturation was reduced [47]. A limitation in their study is that their study did not state the mode of determining the effect of working gas capacity fraction, the reservoir pressure, and the irreducible water saturation on the amount of hydrogen recovered which is particularly important in underground hydrogen storage. In summary, the numerical studies that have been reviewed in addition to the laboratory experiments and implementation in the field serve as a first pass preliminary guide in the selection criteria in optimizing underground storage of hydrogen.

The researchers Lysyy et al. (2021) identified and utilized three stages of hydrogen storage including – initialization, cyclic operation, and prolonged withdrawal in their simulation model. Their simulation involved two stages with the first stage which was defined as the reference stage involved the storage of hydrogen in a designated well [64]. The second stage, which was defined as a case study, assessed the effect of different parameters such as cushion gas, structural geometries, and injected gas compositions. Their simulation model studied injection in three different zones — oil, gas, and water zones applying three stages in the simulation comprising – initialization, cyclic operation, and prolonged withdrawal [64].

1.11 Effect of Prolonged withdrawal of hydrogen

A simulation study conducted by Lysyy et al. (2021), consisted of a seasonal underground hydrogen storage operation with four annual cycles, and a five-month withdrawal and a seven-month injection period with each cycle [64]. After the initialization was completed, the cyclic operation stage was started quickly afterwards with the operating conditions of withdrawal and injection rate limits of 3 million m^3/day and BHP limits of between 180—270 bar as the lower and the higher limits. The average pressure of this reservoir system before the hydrogen injection was 250 psi. The authors noted that the decision to maintain the lower bottomhole pressure (BHP) limit guaranteed a constant hydrogen deliverability during operation could be achieved. It was further noted that a prolonged withdrawal period was simulated to estimate the final hydrogen recovery factors after the fourth withdrawal or injection cycles. The prolonged withdrawal period had a controlled rate of 3 million m^3/day and a lower BHP limit of 130 bar to be able to accommodate the average reservoir pressure limit before the start of injection which was 250 bars. They set an economic limit of 1 million m^3/day of hydrogen for their prolonged withdrawal period after a thorough economic project analysis [64], [80].

Lysyy et al (2021) in their results summary from the storage site initialization stage in the gas, oil, and water for the reference case, noted that for the hydrogen injection rate and the bottomhole pressure in the designated well: a constant rate and gradual pressure development characterized the injection in the gas zone. A variable injection rate was observed in the water zone due to an immediate attainment of the BHP upper limit. They observed that the gas zone did not reach the BHP limit and maintained constant injection during the injection period while the water zone BHP limit was reached at initialization stage due to poor vertical communication and high-water saturation. It was observed that lower storage capacities for oil and water zones relative to the gas zones occurred due to the presence of immiscible fluids and reduced displacement efficiencies.

Table 4: Summary results of hydrogen storage in the reference case, case 1, 2 & 3 in all storage zones (Lysyy et al., 2021) [64].

		Initialization			Cyclic operation			Prolonged withdrawal	
Storage Zone	**Case**	**Duration [days]**	**Total H2 injected [billion m3]**	**H2 ratio in totally injected gas**	**H2 withdrawn first cycle [billion m3]**	**H2 recovery factor first cycle**	**Lowest H2 fraction withdrawn 1st cycle**	**Total hydrogen withdrawn [billion m3]**	**Final H2 recovery factor**
Gas	Ref case	1085	3.26	100%	0.432	13%	100	4.78	87%
	Case 1A	1219	0.75	20%	0.436	58%	81	2.76	93%
	Case 1B	1196	1.28	36%	0.456	36%	96	3.28	94%
	Case 1C	1124	2.32	60%	0.46	20%	99	4.18	92%
	Case 2	1203	1.08	30%	0.137	13%	25	1.58	91%
	Case 3	1193	3.37	100%	0.497	15%	100	4.06	77%
Oil	Ref case	999	2.91	100%	0.462	16%	100	3.91	77%
	Case 1A	1079	0.84	26%	0.436	52%	82	2.93	95%
	Case 1B	1047	1.41	45%	0.452	32%	96	3.39	92%
	Case 1C	1007	2.38	80%	0.461	19%	25	3.88	84%
	Case 2	1133	0.97	30%	0.126	13%	95	1.32	82%
	Case 3	1347	3.09	100%	0.429	14%	100	2.76	61%
Water	Ref case	1928	3.05	100%	0.373	12%	100	2.07	49%

Case 1A	2309	0.69	20%	0.356	52%	72	1.63	84%
Case 1B	2153	1.49	45%	0.384	26%	95	1.9	70%
Case 1C	1967	2.58	82%	0.374	15%	99	2.04	55%
Case 2	2228	0.98	30%	0.085	9%	22	0.62	47%
Case 3	1047	3.14	100%	0.473	15%	100	1.73	38%

1.12 Underground storage systems from Haynesville Shale Play (Singh, 2022)

Singh (2022) noted that Haynesville shale play among various shale and tight oil & gas formations in the U.S., such as Barnett, Marcellus, Utica are four major dry gas formations. Haynesville was noted to be the newest field to be developed while Barnett is the oldest and had a lot of pioneer horizontal wells being drilled in shales [81]. The geological description of Haynesville is such with rich organic matter content with mudstone from Upper Jurassic age lying at the depth of 10,300 — 14,500 ft. with thickness of 100 — 350 ft. A proximate field which overlays Haynesville is the Bossier shale. Some jurisdictions refer to a combined Haynesville/Bossier field together as Haynesville [81].

Singh (2022) has summarized some critical parameters for comparison for conventional underground storage resources for hydrogen with depleted shale gas lateral wells obtaining values for conventional underground storage resources from various literature sources. Table 2 shows different underground storage resources for each parameter relevant to storage. Underground storage resources shown in the tables include depleted gas wells, depleted conventional reservoirs, salt caverns, abandoned mines, aquifers, lined rock caverns. Parameters relevant to storage such as hydrogen storage capacity, amount of cushion gas, and maximum flow rate were shown in the tables.

Table 5: Summary comparison of underground hydrogen storage systems (Sing Harpreet, 2022) [81]

Parameters	Salt Caverns	Abandoned Mines	Aquifers	Lined Rock Caverns	Depleted conventional reservoirs
Maximum flow rate (MMSCFD)	33.2	49.6	39.2	49.6	54.9
Hydrogen storage capacity (tons)	-6000	-6000	-6000	-2000	-7000
Cushion gas (tons)	-2000	<2000	-6000	-2000	-3500
Storage interval depth (ft)	≤3000	≤1000	≤15000	≥3000	≥4000
Purity of produced Hydrogen	95%	95%	N/A	100%	N/A
Risk of leakage	4th highest risk	3rd highest risk	Highest risk	Lowest risk	2nd highest risk

2.0 Methods

2.1 Enhanced Hydrogen Storage Simulation Model

A hypothetical reservoir model was developed in order to further understand the reservoir and geological factors and parameters that facilitate efficient hydrogen injection and withdrawal for large-scale hydrogen storage. The Computer Modelling Group (CMG) reservoir simulation software was used to simulate hydrogen storage and transport in porous media.

The rock compressibility, Cr was determined by using the Newman's correlation for consolidated sandstone reservoirs (Newman, 1973)[82]:

$$Cr = \frac{97.3 * 10^{-6}}{(1+55.9\emptyset)^{1.429}}$$

Table 6: The base case parameters as used in the model.

Property description	**Value**	**Unit**
Reservoir porosity	0.2	Fraction
Horizontal reservoir permeability	100	millidarcy
Vertical reservoir permeability	100	millidarcy
Reservoir temperature	50	deg C
Reservoir compressibility	5.8e-7	/kPa
Water compressibility	4.35 e-7	/kPa
Bottomhole pressure	11000	kPa
Gas injection rate	244565	m3/day

For the base case scenario in the model constraints, a single well was modelled to inject 244565.22 m3/day of hydrogen as the surface gas injection rate. The base case bottomhole pressure was set at 11000 kPa at a datum depth of 1014 m. The injector well was placed at the center of the reservoir, and it is perforated over the top 40 m of the reservoir. 1 injector well and 1 producer well were used in the model. The water-gas-contact (WOC) was 600 m. The reference reservoir pressure was set at 6400 kPa at a datum depth of 650 m.

The caprock was assumed to be tight with respect to the stored gases hence it was presented in the simulation model as a no-flow boundary. It was assumed that diffusion within the gas phase was neglected while degradation of the injected hydrogen was not incorporated. Assumption was made for the gas cap initialization that it contains no residual oil saturation.

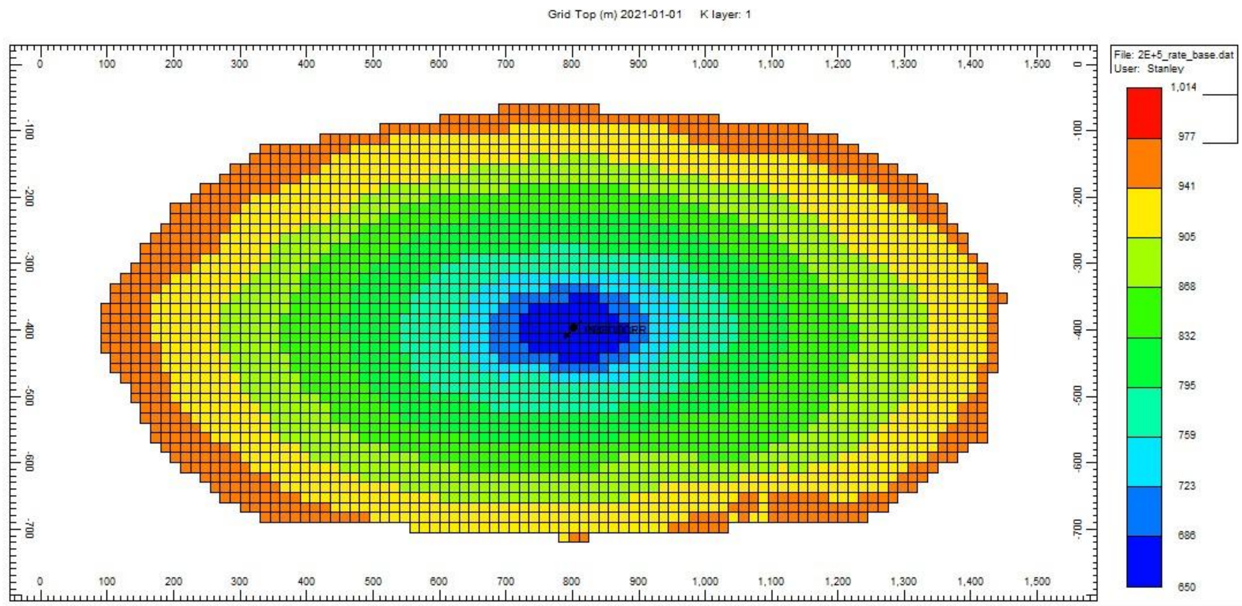

Figure 2: Numerical simulation of the reservoir showing the depth of the reservoir.

The grid was structured as a corner Point of 91 x 44 x 10 with total blocks of 40040. The grid is a single porosity type with Pinchout Thickness of 0.0002 m. The model was set to accommodate a minimum allowable bottomhole pressure of 30 kPa while the effect of any skin on the well flow rates was neglected. The model was initialized by enumeration whereby the fluid saturations were specified.

2.2 Fluid Saturation Curves

Relative Permeability (K_r) vs Water Saturation (S_w)

The average water saturation was calculated as 0.61 from the model. The average water relative permeability was calculated as 0.37 while the average oil-water relative permeability was found to be 0.22 from the model.

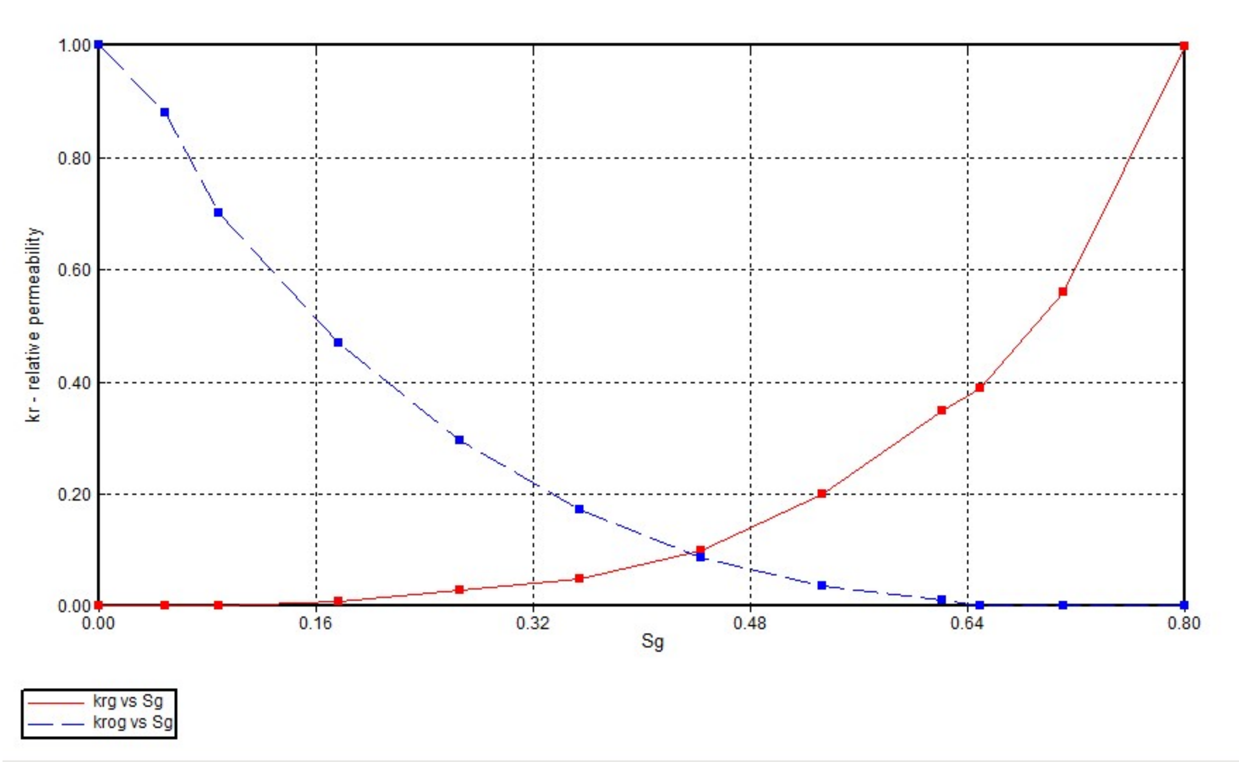

Figure 3: Relative permeability vs water saturation curve of the reservoir model

2.3 Relative Permeability (K_r) vs Gas Saturation (S_g)

Average gas saturation (S_g) of 0.39 was determined in the model. The average relative gas permeability (K_{rg}) was determined as 0.22 while the gas-oil relative permeability (K_{rog}) was calculated as 0.30.

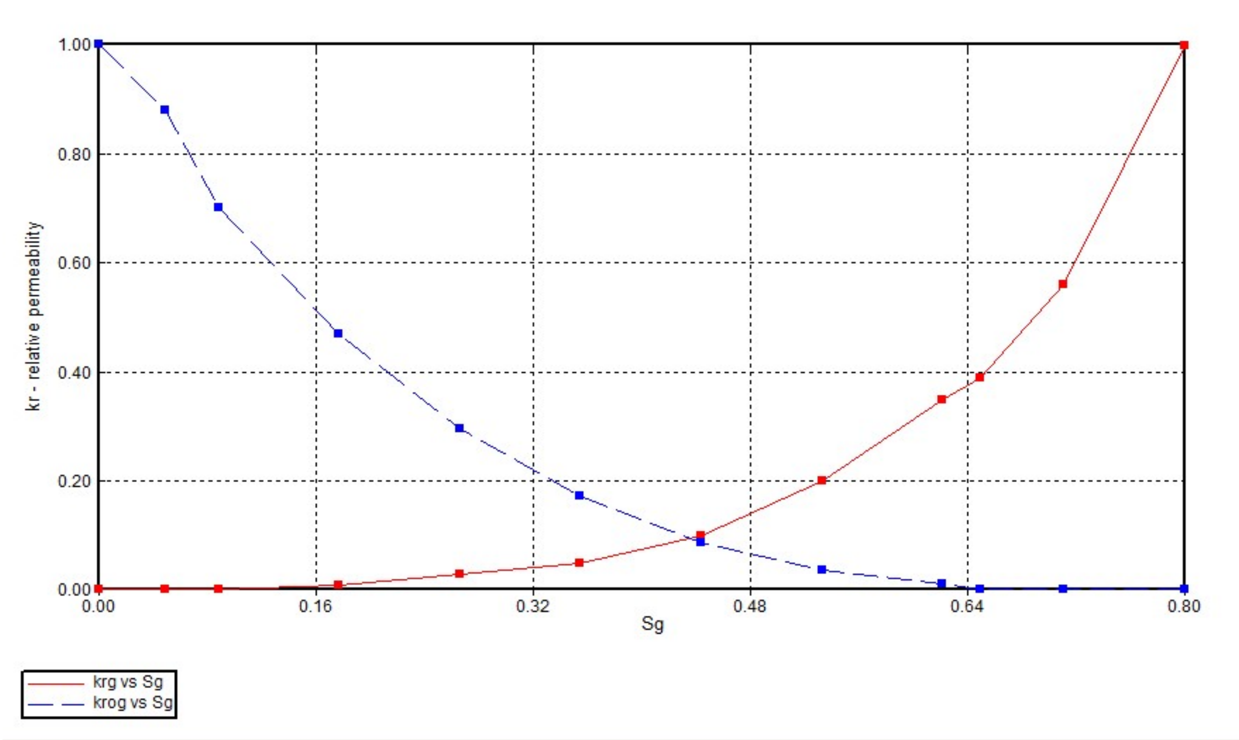

Figure 4: Relative permeability vs water saturation curve of the reservoir model

3.0 Field Analysis of hydrogen storage project

3.1 Sensitivity analysis on the effect of injection pressure on hydrogen storage

Results from simulation runs on pressure show that the injection pressure has a significant impact on the mass of hydrogen stored in the reservoir. The base pressure of 11000 kPa that was chosen in the model coincidentally gave the best-case performance in terms of the mass of hydrogen stored. Reductions in the injection pressure bottomhole pressure subsequently led to a decrease in the mass of hydrogen stored.

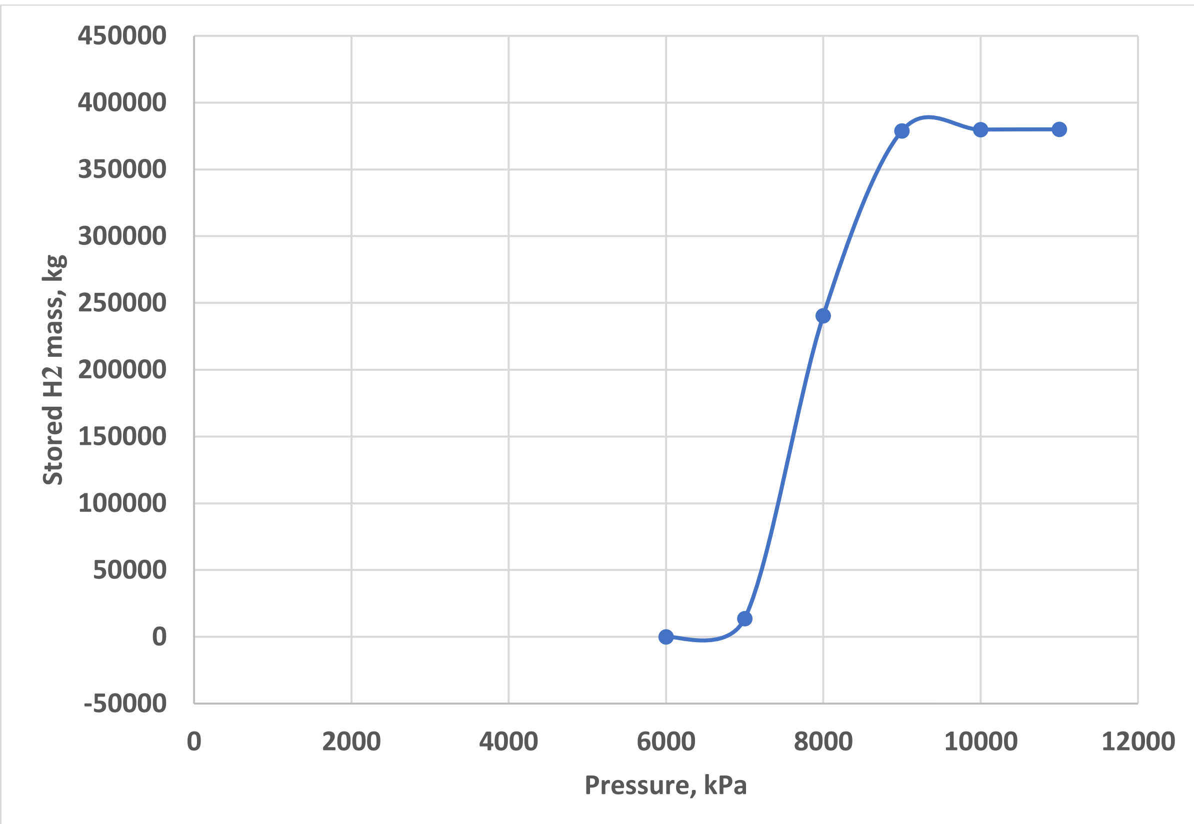

Figure 5: Effect of injection pressure on underground hydrogen storage

3.2 Cushion gas sensitivity analysis

The effect of different cushion gases on hydrogen storage was compared among three gases including – nitrogen, methane, and CO_2. The concept of cushion gas has been explained earlier in this work. In the base model, hydrogen was solely injected without any cushion gas. Sensitivity analyses on using Nitrogen as cushion gas involved injecting mole fraction of hydrogen as cushion gas ranging from 0.1 to 0.4 while the remaining mole fraction was injected hydrogen. The mole fraction for each case between the nitrogen cushion gas and hydrogen must be equal to 1. The process was repeated for the two other cushion gases – methane and CO_2. The plot shows cumulative gas moles of hydrogen stored for the various mole fraction scenarios of injected cushion gas (Nitrogen, methane, or CO_2).

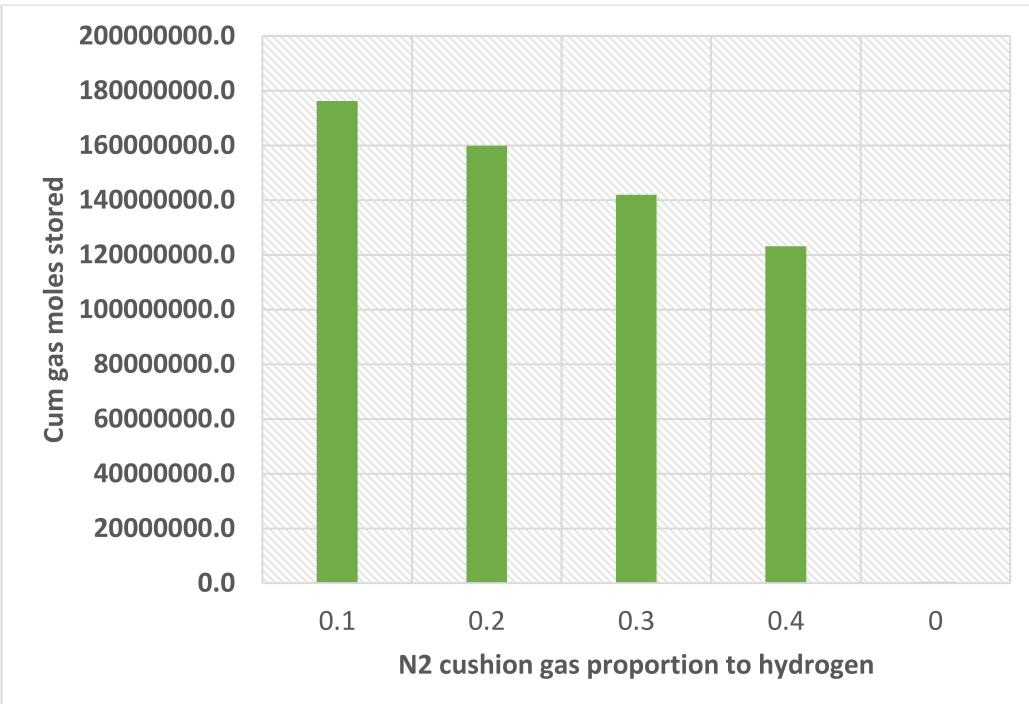

Figure 6: Effect of N_2 cushion gas on hydrogen storage

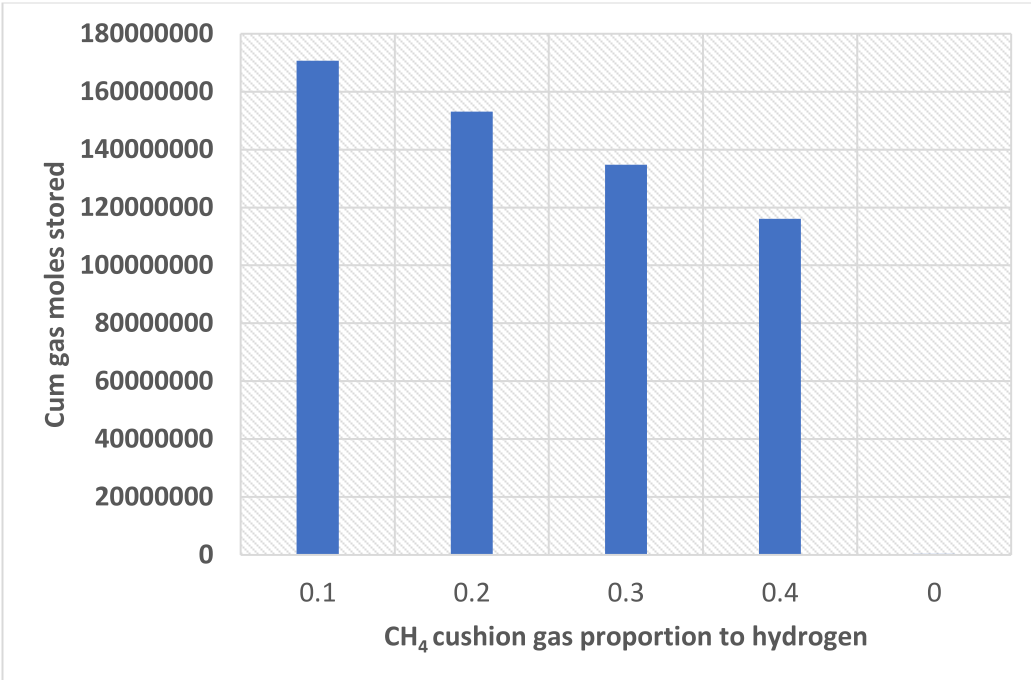

Figure 7: Effect methane used as cushion gas on hydrogen storage.

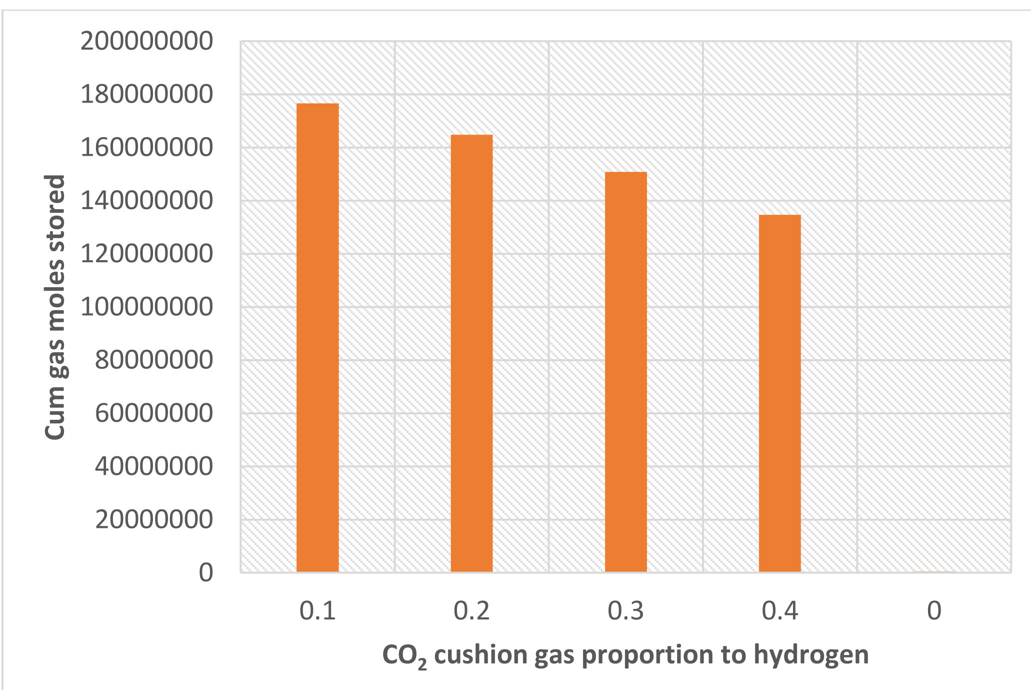

Figure 8: Effect of CO_2 as cushion gas on hydrogen storage

A comparison of the 3 cushion gases used shows CO_2 cushion gas at mole fraction of 0.1 mole was the best performing cushion gas as seen from the results.

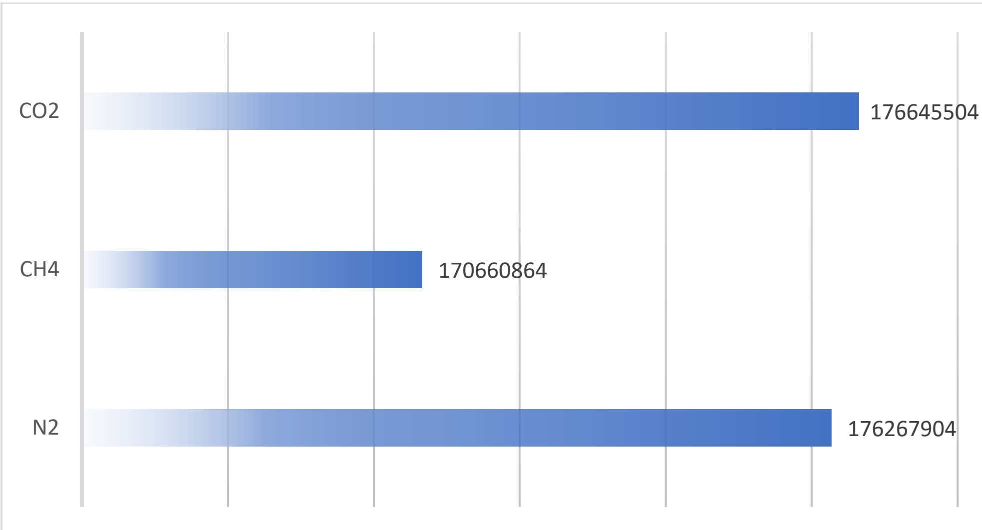

Figure 9: Comparison of the three cushion gases used in the simulation.

3.3 Parameters that impact hydrogen storage

Sensitivity studies were carried out to evaluate reservoir and well parameters that have significant impact on the amount of hydrogen stored through the simulation project. The base permeability from the base-case model was 100 MD which was subsequently adjusted by running sensitivities with lower permeability values. The amount of hydrogen stored increased as the reservoir permeability was reduced showing that more hydrogen is stored as the reservoir becomes tighter. Conversely, for porosity when the porosity was increased, the amount of hydrogen stored increased indicating that more pores spaces are available for underground hydrogen storage.

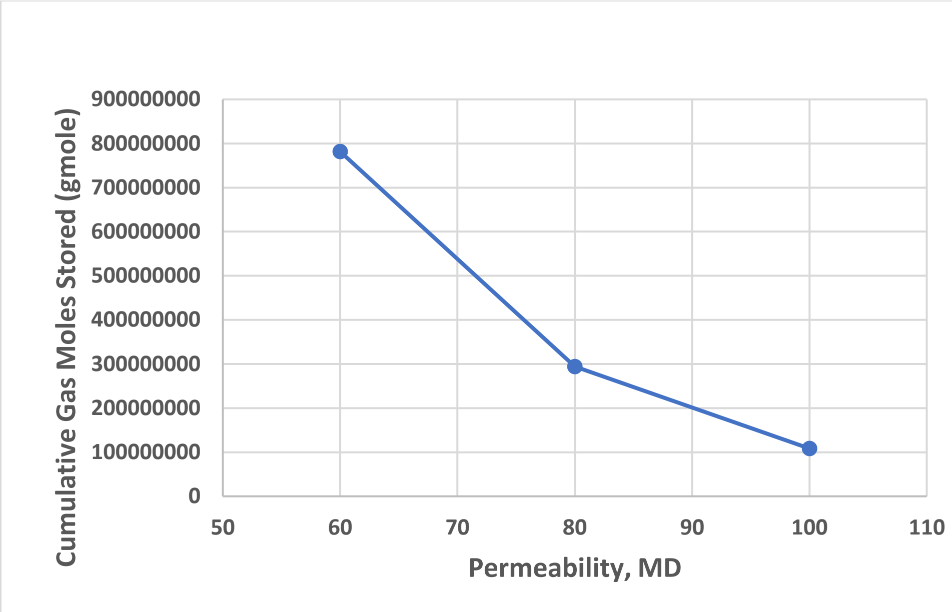

Figure 10: Impact of permeability variation on hydrogen storage

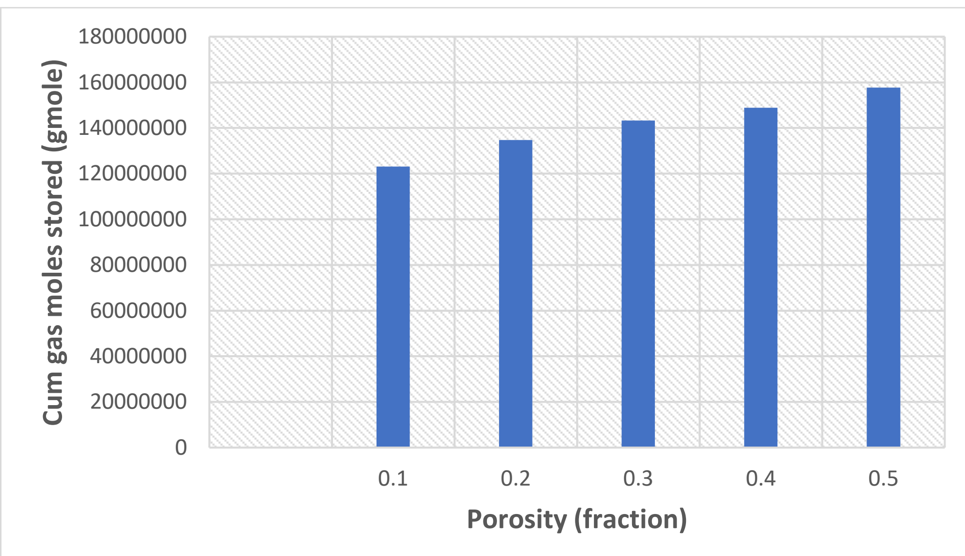

Figure 11: Effect of porosity variation on hydrogen storage

Sensitivity runs were carried out on the surface injection rates for hydrogen by adjusting the injection rates from above and below the base injection rate from the base-case of 244565 Sm3/day. The initial loss of hydrogen that was observed as the injection rates were reduced from

10000 Sm3/day to around the base injection rate of 244565 Sm3/day is attributed to the effect of hydrogen fingering which could have led to early breakthrough and hydrogen loss. Subsequently the amount of hydrogen stored started to increase at injection rates above the base injection rate.

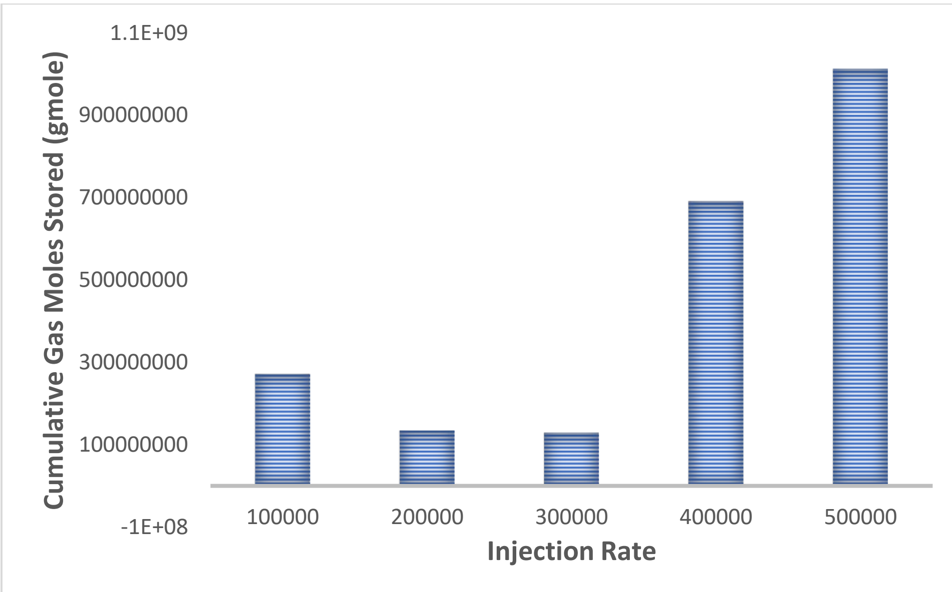

Figure 12: Effect of injection rate variation on hydrogen storage

4.0 Conclusion and remarks

A review of previous research on underground hydrogen storage (UHS) has been effectively carried out detailing several concepts about the topic as well as factors or parameters that impact underground hydrogen storage. Some underground hydrogen storage sites were also reviewed.

CO_2 as cushion gas performed best in terms of hydrogen storage which was slightly followed by Nitrogen. CO_2 as a cushion gas for hydrogen storage would serve as a positive advantage for Carbon Capture Utilization and Storage (CCUS).

The effect of reservoir and well parameters on hydrogen storage potentials was carried out through several sensitivity runs on the base model. For the injection pressure, results show that increase in the injection pressure increased the mass of hydrogen stored till an optimum mass (180000kg) of hydrogen storage was attained during the injection exercise.

The effect of permeability variation showed that lowering the permeability below the base-case value of 100 MD resulted to increased hydrogen storage potential. Conversely, porosity increasing values resulted to increased hydrogen storage potential due to available pore spaces to stored additional hydrogen.

The impact of surface injection pressure on the hydrogen storage potential was studied using the base model. Initial increase in the hydrogen injection rates at the surface resulted in initial decrease in the hydrogen storage potential but subsequent increase to injection rates above the base-case injection rate of 244565 Sm3/day resulted to increased hydrogen storage potential. This irregular behavior is ascribed to the compression effect of cushion gas during the initial stages of the injection.

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