Utility-scale Subsurface Hydrogen Storage: UK Perspectives and Technology

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Abstract

To reduce effects from anthropogenically induced climate change renewable energy systems are being implemented at an accelerated rate, the UKs wind capacity alone is set to more than double by 2030. However, the intermittency associated with these systems presents a challenge to their effective implementation. This is estimated to lead to the curtailment of up to 7.72TWh by 2030. Through electrolysis, this surplus can be stored chemically in the form of hydrogen to contribute to the 15TWh required by 2050. The low density of hydrogen constrains above ground utility-scale storage systems and thus leads to exploration of the subsurface.

This literature review describes the challenges and barriers, geological criteria and geographical availability of all utility-scale hydrogen storage technologies with a unique UK perspective. This is furthered by discussion of current research (primarily numerical models), with particular attention to porous storage as geographical constraints will necessitate its deployment within the UK. Finally, avenues of research which could further current understanding are discussed.

Keywords: Subsurface Hydrogen Storage, Deep Aquifer, Depleted Oil/Gas Deposits, Salt Cavern, United Kingdom

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1. Introduction

In order to align with the UK's net-zero CO_2 emission goal of 2050, and Scotland's at an accelerated rate of 2045, considerable efforts are required to reduce emissions from all sectors[3]. This has led to the rapid investment in renewable energy systems (RES) which has seen Scotland generate 90.1% and the UK as a whole 36.9% of its electricity demand in 2019 from RES[4]. However, the intermittent nature of RES can lead to offsets between demand and supply necessitating curtailment of this clean energy source. Thus, a means of energy storage is required.

Of the current global energy storage capacity, pumped hydro storage systems occupy nearly 99%; however, geographic restrictions prevent utilisation[5]. An alternative to this capable of a scale even greater than that of pumped hydro systems is subsurface hydrogen storage; how this compares to other forms is presented in *Figure 1*. Compared to systems capable of similar capacities, i.e. pumped hydro storage efficiency at approximately 60-80%, subsurface hydrogen storage has relatively lower efficiency at approximately 30-40%[6]. However, its high energy density (at reservoir pressure), its multisector capabilities (heating, electricity generation, transport) reduced environmental impact and increased safety are attributes which make it suitable for long term storage[7, 8].

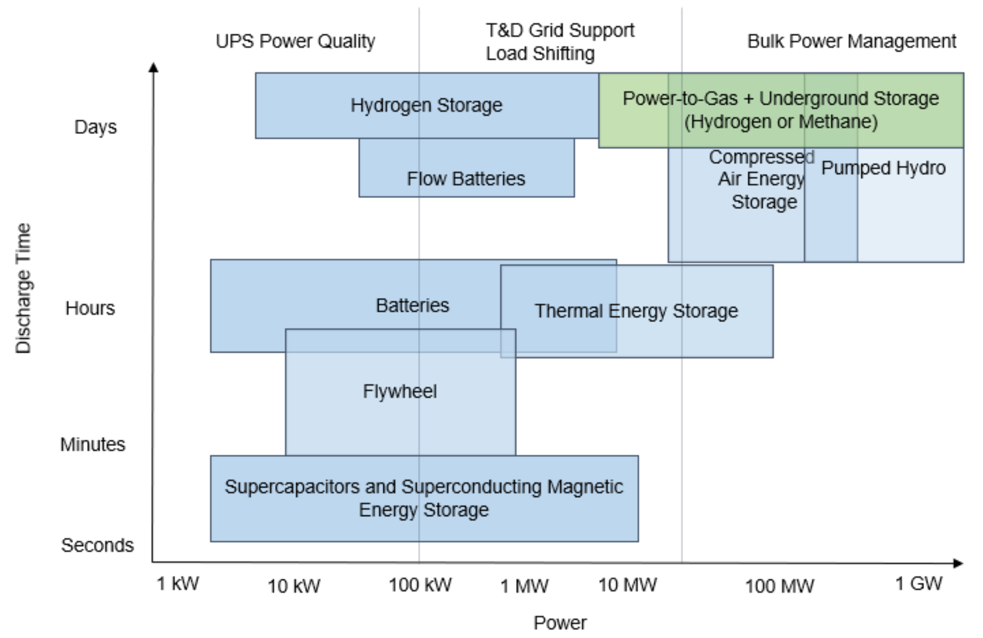

Figure 1. Graph displaying the power capacity and relative discharge times for various energy storage technologies, highlighted in green is the hydrogen storage considered in this review. Adapted from [6]

Hydrogen can be produced through a plethora of processes, however, when discussing production the two means normally considered are: 1) Steam methane reforming (SMR – grey hydrogen, SMR+ CCS(carbon capture and sequestration) – blue hydrogen), a carbon emitting endothermic process utilising a fossil fuel feedstock; and 2) Water electrolysis (green hydrogen), zero-emission technology (when powered through RES) requiring only water and electrical energy input[9, 10]. Hydrogen production technologies are out with the scope of this study; more on these can be found in [10-16].

The UK government anticipates hydrogen to play a key role in the net-zero transition, primarily aiding in the decarbonisation of heat and long-distance travel such as heavy goods vehicles[3]. This is outlined in the net-zero document where a minimum increase of over seven times the production capacity (27TWh) from the 2019 is estimated for blue hydrogen alone [3]. This capacity is reinforced by the UK's natural gas delivery network the *National Grid* in their recent *Future Energy Scenarios* (*FES*) paper, stating a minimum requirement of 190TWh to deliver a net-zero scenario[2]. However, in a fully adopted scenario, an annual production capacity of ~710TWh was estimated[17]. In all estimates, this capacity is anticipated to be met predominantly through SMR+CCS, however, where flow variability is not as constrained RES can offer a low carbon solution (i.e. storage)[3, 17]. This was predicted to require a minimum of 15TWh total capacity by the *National Grid* [2]. Utilisation of utility-scale hydrogen could provide a considerable contribution to the decarbonisation of the atmosphere; as well as aiding in the performance of the grid – allowing for better management of energy supply and demand[18]

Above-ground storage of this green energy vector is constrained through its relatively low density equating to roughly $11.9 m^3/kgH_2$ at atmospheric pressure and 15°C [19]. To create a viable storage option a mean of increasing the energy density is required; resulting in the compression, liquification and even molecular bonding mechanisms to do so. To induce the phase change at atmospheric pressure hydrogen must be cooled to -240°C which in an ideal scenario would require 6 $kWh/kg{\cdot}LH_2$; however, current technology requires 11-13 $kWh/kg{\cdot}LH_2$,the equivalent to one third of its energy content[20]. This has led to the development of subsurface storage, storing compressed hydrogen in geological formations to compensate for the storage volume required.

Subsurface hydrogen storage can be categorised by the mechanism in which the hydrogen is stored;

- Cavern – salt cavern and engineered (lined rock) caverns
- Porous storage – aquifer and depleted oil/gas fields (hydrocarbon deposits)

As this paper aims to address utility-scale capacities, engineered (lined) rock caverns are not considered due to its low capacity and increased costs[21]. Each technology has been proven for natural gas storage; however, salt cavern storage is the only utilised commercially for hydrogen with four sites globally – three in the U.S and one in Teesside, UK[20]. Drawing from this previous petrochemical experience will be essential in porous storage development, with 85 aquifers and 476 depleted oil/gas fields accounting for 12% and 80% of the global working gas capacity respectively[22].

This paper aims to provide an updated perspective on technologies capable of storing the capacities generated through renewable energy curtailment; as well as contributing the 15TWh stated by *National Grid*[2]. A case for utility-scale hydrogen storage development and implementation is presented through establishing potential requirements from wind power curtailment alone; as well as presenting the current gas infrastructure available if repurposing was conducted. A review of possible utility-scale technologies is presented with specific attention given to; challenges and barriers, geological criteria, cost and geographical availability. To conclude, this paper provides a more in-depth review than has previously been conducted on the models constructed and future aspects for developing them. Additionally, the current and future physical testing is discussed and avenues for development are suggested.

2. Why is Utility Scale Storage Necessary?

2.1. Curtailment of Renewable Energies

Renewable energy systems, specifically wind power in this scenario, are plagued with unpredictable intermittency at both seasonal and temporal scales, generating periods of both surplus and deficits in supply. In periods of deficits this can be addressed through use of non-renewable sources to ensure supply; however, when surplus energy is available and not required, in the absence of storage these systems must be curtailed. Other logistical reasons for curtailment include highly congested transmission networks, slow transmission network development, fuel price variability, varying demand profile (system balancing issues) as well as geographical location and inertial constraints (excessive wind speed)[23, 24].

The curtailment of wind power is not UK specific but is global in scope[24]. Comparing this to other countries within Europe, in 2015 the UK came only second to Germany when compared to Germany, Ireland, Italy and Spain; being only 32% of Germanys 4.12TWh. More recently, the UK has seen its 2015 value more than double in 2020, rejecting 3.70TWh of clean energy at a cost of £274m to the UK government(see *Figure 2*)[25].

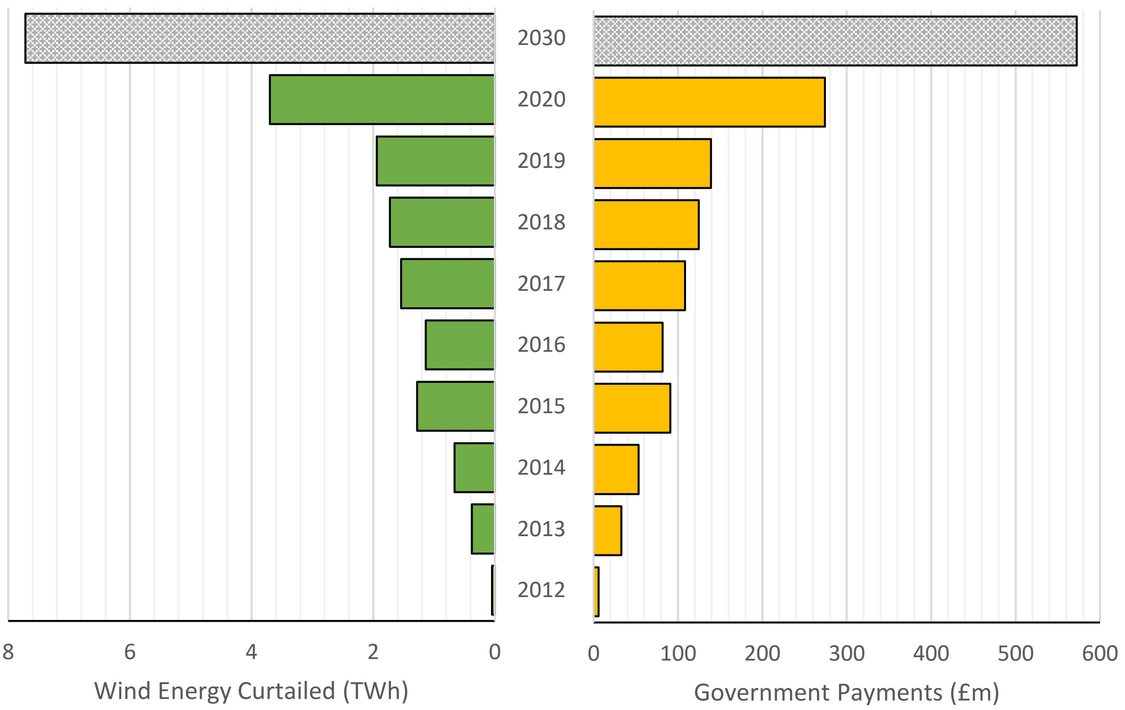

Figure 2. Historical annual curtailment of wind power within the UK and constraint payments made by the government, grey patterns represent projected values **[25]**

To assess how this could potentially develop by 2030 the historical installed wind capacity, generation and curtailment are required. Generally, an increased capacity would correspond to an increase curtailment; this is not always the case, as in 2016 (see *Figure 3* and [26]). As such an estimation based on the generation can provide a more representative value. To do such *Equation 1* was used.

$$E_{2030} = P_{2030} * \frac{\sum_{i=2012}^{2020}\left(\frac{E_i}{P_i}\right)}{9} \qquad [1]$$

where E_i is the electricity generation at year i; P_i is the capacity at year i. The average ratios of the electricity generation to the capacity over the previous nine years (taken from 2012 – 2020) were used to estimate the generation in 2030 (E_{2030}). This was accomplished for both onshore and offshore wind to consider their varying load factor, with predicted capacities being 30GW and 40GW (P_{2030}: total capacity of 70GW) respectively[1, 27]. This method was tested (based on previous years until 2012) as an approximation tool for 2013-2020 and found an absolute error of ±5.36% from the historical values. Furthermore, the accuracy of the prediction has been improved with an error of ±2.15% when the abnormally low generation of 2016 was excluded; hence, it was considered appropriate. The estimated generation is then multiplied by the historical average of the wind curtailment (2015-20) to produce the 2030 curtailment estimate. This was deemed sufficient as prior to 2020 (between 2015-19), curtailment had plateaued in relation to electricity generated at 3.095±0.075% of the total electrical energy generated[25, 26]. The installed capacity was taken as the Q4 value from the previous year as the initial value for the following year (i.e. the 2019 Q4 value was used for 2020)[26].

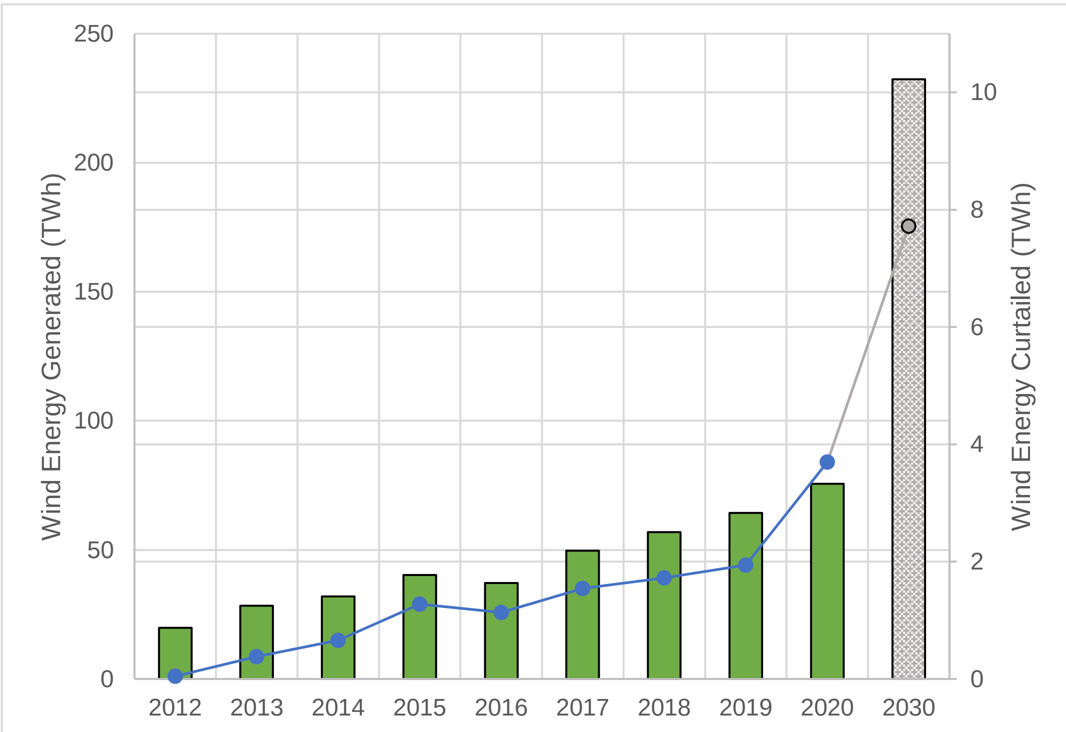

Figure 3. Historical UK wind generation (bar chart) and annual curtailed wind energy (line and marker). Grey values are estimates based on historical data[25, 26].

Under the assumption that both capacities are met[1, 27], a potential curtailment of 7.72TWh could occur in 2030. Utilizing the constraint payment values for 2020 (£74/MWh[25]), this would correspond to government payments of £573M by 2030(see *Figure 2*).

As can be seen in *Figure 3*, a considerable increase between 2019-20 curtailment occurs. This increase is expected to stem from both the slow transmission system development in relation to considerable increase in offshore production capacity (21%[26]) and the decrease in electricity demand resulting from COVID-19[28]. The influence of slow transmission system development is difficult to approximate and as such could result in a substantially underestimated value. In addition to this, the effect of the UK's increasingly decentralised energy network is not taken into consideration[29]. To provide a more robust approximation, consideration of factors such as, commitment of power generation units (difficult to reverse in short term), regional demand and generation profiles and distributed systems load profile and cost[23, 30].

Utilizing hydrogen as an energy vector for this curtailed energy would both reduce wastage and aid in the abatement of government spending; with additional value being found in the quality of hydrogen this can produce (e.g. can be used in proton exchange membrane fuel cell (PEM-FC))[31]. This 7.72TWh could produce over 133,000tonnes of hydrogen (58kWh/kg[32]), with a thermal energy capacity of 4.43TWh (based on a lower heating value of 33.3kWh/kg); a considerable contribution to the 15TWh minimum specified in the *Future Energy Scenarios* paper[2]..

By utilizing otherwise curtailed wind power for producing hydrogen for storage, the dependence on the intermittent source is reduced. Further flexibility can be provided PEM electrolysis allowing operation as low as 5% of the design load [14]. This aligns with reservoir filling as compared to grid requirements lower injection rates would be necessary; porous storage actually being restricted due to viscous forces[22, 33].

2.2. Natural Gas Infrastructure

Hydrogen is often considered a green alternative to natural gas as it emits zero CO_2 during the release of energy and provides the same multisector capabilities that natural gas does. This has led to the suggestion of repurposing natural gas infrastructure. The current UK storage capacity of natural gas, is approximately 16TWh; compared to that of hydrogen, wherein Teesside is the only large-scale storage with ~1000 tonnes (33.3GWh) [34]. This 16TWh of natural gas storage is a result of the closure of the *Centrica's Rough Gas Storage Facility* which previously held 71% of the UK's natural gas storage, reducing the subsurface storage capabilities to just six days of the average demand[35, 36]. When compared to that of Germany, which during 2015 was capable of storing 80 days' worth of consumption, this is substantially less[37]. Both the *Committee on Climate Change* (CCC) and the *National Grid* believe that some degree of repurposing will be required to deliver and store hydrogen[2, 3, 38]. *Equation 2* allows for the volumetric capacity to be compared.

$$Volume_{H_2} = \frac{Volume_{NG} * Energy\ Density_{NG}}{Energy\ Density_{H_2}} \qquad [2]$$

Where $Volume_{H_2}$ represents the estimated volumetric storage capacity of hydrogen, $Volume_{NG}$ represents the volumetric storage of natural gas, $Energy\ Density_{NG}$ and $Energy\ Density_{H_2}$ represent volumetric energy densities of natural gas and hydrogen, respectively. Based-on *Equation 2* (and utilising the lower heating value), to provide the same energy capacity of current natural gas storage, an additional 232% of the volumetric capacity would be required; which already stands at 1.73 billion cubic metres (bcm) of natural gas[39]. Furthermore, thermophysical phenomena such as viscous fingering that could reduce the recoverable hydrogen are not considered; suggesting an even greater volumetric capacity may be required [33]. Currently, this 1.73bcm of capacity is met with 24% depleted gas fields and 76% salt cavern storage (see *Figure 4*).

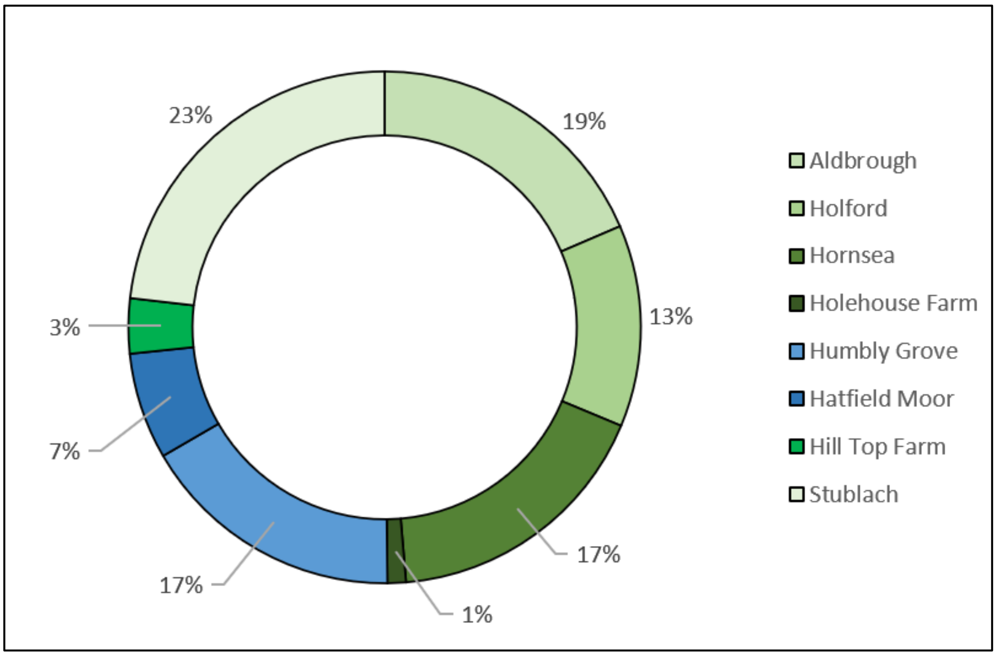

Figure 4. UK natural gas storage facilities and their share of capacity[39].

Building on the concept of repurposing, it is also suggested that the use of the national transmission system (NTS), a high-pressure pipeline rated to 85bar, could facilitate the storage of this hydrogen via blending with the natural gas[38, 39]. HyNTS is *National Grids* current project analysing the use of such for transportation of hydrogen; however, the use for storage is relatively unexplored[39]. Other initiatives such as Hy4Heat are assessing the low-pressure pipeline for 100% hydrogen use; however, operating at only 7 bar results in under 1/10th the density at 85bar[38, 39].

From pipe lengths and diameters specified in *The National Grids*, NTS transmission maps[39], and approximated minimum pipe thickness (18mm), the total volumetric capacity of the NTS system is estimated to hold an equivalent of ~30,000 tonnes could be stored (assuming an ambient temperature of 15°C). Without conversion losses this would equate to 0.99TWh of capacity, the equivalent to 6.62% of the *National Grid* specified minimum 15TWh capacity necessary for a successful net-zero transition by 2050[2]. This storage potential is further reduced when the operational requirement within the NTS is considered. A conservative approximation was used to estimate the capabilities of NTS, an 80-day period during both winter and summer were considered. *Equation 3* was used to determine the storage capacity.

$$\frac{V_{summer_{avg}}}{V_{NG(max)}} * V_{NTS} * \rho_{H_2} = M_{H_2} \quad [3]$$

Where $V_{summer\ avg}$ represents the average instantaneous flow for the 80-day period, $V_{NG(max)}$ represents the maximum natural gas capacity, V_{NTS} is the total internal pipe volume and ρ_{H2} is the density of hydrogen at 85bar and 15°C. This determined that a reduction to 10,446 and 18,336 tonnes of hydrogen could be stored in winter and summer respectively[40]. This is the equivalent to 0.35 TWh and 0.61TWh, a maximum of 4.07% of the minimum capacity required to meet net-zero in the *Future Energy Scenarios* paper [2]. Furthermore, this does not consider demand fluctuations which could require immediate increase in flow, reducing the storage potential further.

Of the net-zero meeting scenarios outlined in the Future Energy Scenarios paper, a minimum of 15TWh is required for balancing purposes, with an average of 17.7TWh[2]. Additionally, in the "System Transformation" scenario, 14TWh of natural gas storage is still required, as well as separate storage sites for both blue and green hydrogen due to purity variation [2]. Comparing requirements to the current hydrogen capacity, the construction of an additional 455 equally sized storage facilities to that of Teesside would be required[34]. This elucidates the scale of infrastructure development required to integrate hydrogen into the energy mix, and further highlights the need for utility-scale sub surface storage for meeting these goals.

3. Available Subsurface Storage Technologies

3.1. Technology Description

3.1.1. Salt Cavern Storage

Salt cavern storage makes use of chambers formed through dissolution mining (leaching) of naturally occurring salt formations such as domes or layers (beds)[22].These salt formations tend to be above 2000m below ground surface (bgs) as pressures and temperatures below this level make salt deformation more likely, posing stability issues even for well-engineered caverns[21].

Construction of salt cavern storage technologies is performed by injecting water of low salinity into the cavern formation through well boreholes, dissolving the salt in a controlled manner. The brine solution is then extracted from the cavern to leave the cavern geometry; this can be accomplished through the same borehole as a cost reduction measure. This process is known as leaching, and its utilisation is heavily constrained by geographical location[22]. This is where salt caverns are at a disadvantage to other technologies as, unlike porous storage where particles are displaced, the removal and environmentally safe disposal of this brine adds to the costs. The resulting cavern is then filled with a cushion gas, the minimum internal pressure required to prevent salt creep and maintain cavern integrity. The cushion gas should regarded as an initial investment as it is unrecoverable, in general this is taken between 22-33% of the volumetric capacity, meaning a working gas capacity (WGC) of up to 78% could be achieved[22]. Unlike porous technologies, salt caverns do not require intense consideration of multiphase phenomena that could reduce injection rate as residual water gathers at the bottom of the cavity. Other components such as mechanical and thermodynamic effects on the cavern walls geology do require consideration. This allows for numerous injection/withdrawal cycles (up to ten/year), providing the potential for more than just seasonal energy storage[22]. *Figure 5* provides a representation of the salt cavern storage and the effects of different dissolution techniques.

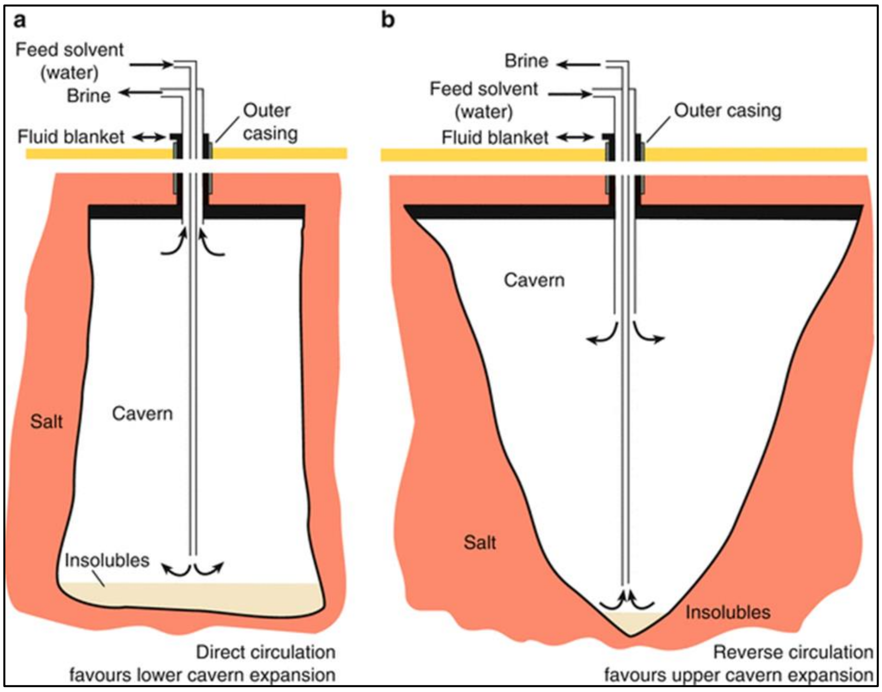

Figure 5. Salt cavern formation via different dissolution system setups [41]

3.1.2. Aquifer Storage

Being an already established technology within natural gas storage (82 sites across the world[22]), aquifer storage has yet to be implemented for hydrogen. Aquifer storage utilises the inherent porous nature of subsurface rocks which occur in sedimentary basins across the world. The aim is to replace these water occupied porous spaces with hydrogen gas [42]. This is accomplished at injection pressures greater than reservoir capillary pressure and less than that of the caprock capillary pressure. This is to allow evacuation of water within reservoir pores throats while preventing leakage through caprock [42]. Water is displaced downwards and outwards creating a seal encapsulating the hydrogen between the low permeability caprock (typically salt or mudstone) and its boundaries. The rate at which this is accomplished must be controlled to prevent gas loss out-with the recoverable boundary[33].

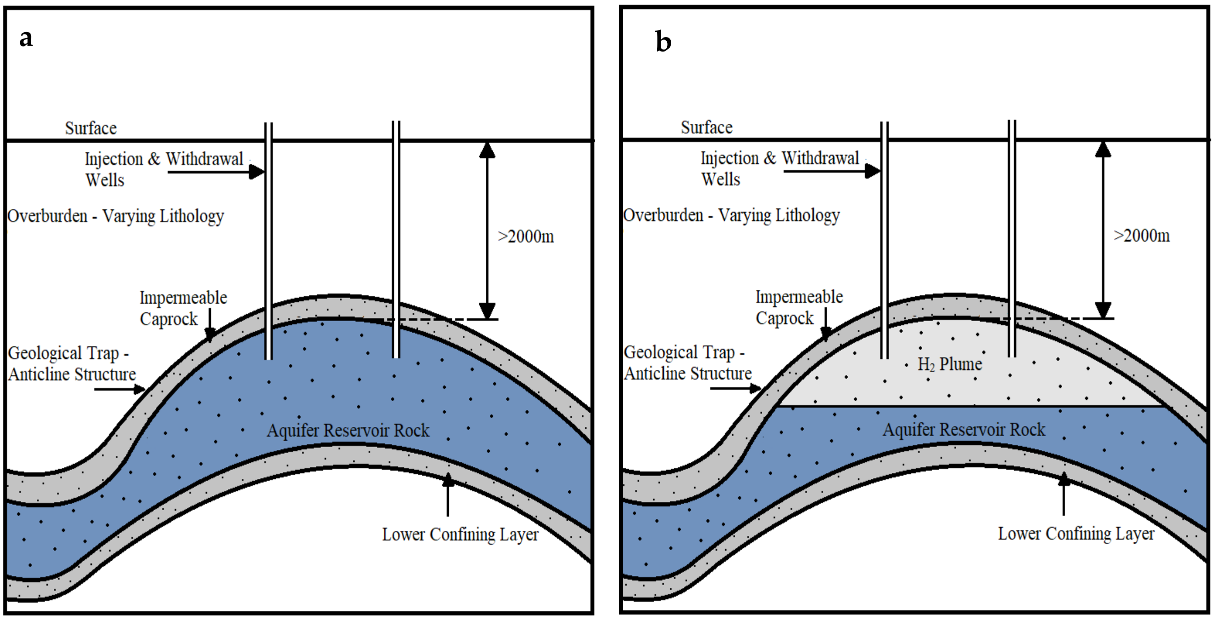

Figure 6. a) Aquifer prior to hydrogen injection b) Aquifer after hydrogen injection is complete. Adapted from [43]

Cushion gas within aquifers is necessary to prevent inwards migration of the water/gas interface and is estimated between 45-80%, suggesting the WGC could be as little as 20% [6, 21, 22]. This is typically accomplished at pressures in excess of 100 bar with formations depths ranging from 500-2000m bgs[6]. Withdrawal is then accomplished through expansion up one of several borehole wells[8]. *Figure 6* presents the injection process and the steep anticline structure necessary to reduce lateral dispersion.

3.1.3. Depleted Oil/Gas Fields

As in aquifer storage, depleted oil/gas fields are proven for natural gas storage, accounting for 75% of the WGC of subsurface storage systems globally[22]. Depleted oil/gas fields can be considered as a specific portion of aquifers (geological trap), where only residual amounts of water are within the pores which are predominantly occupied with trapped oil/gas [6]. Extraction of these hydrocarbons leaves a depleted reservoir with only the native gas required to maintain formation integrity; these traps can then be utilized for hydrogen storage by the same means as that of aquifers (*Figure 7*).

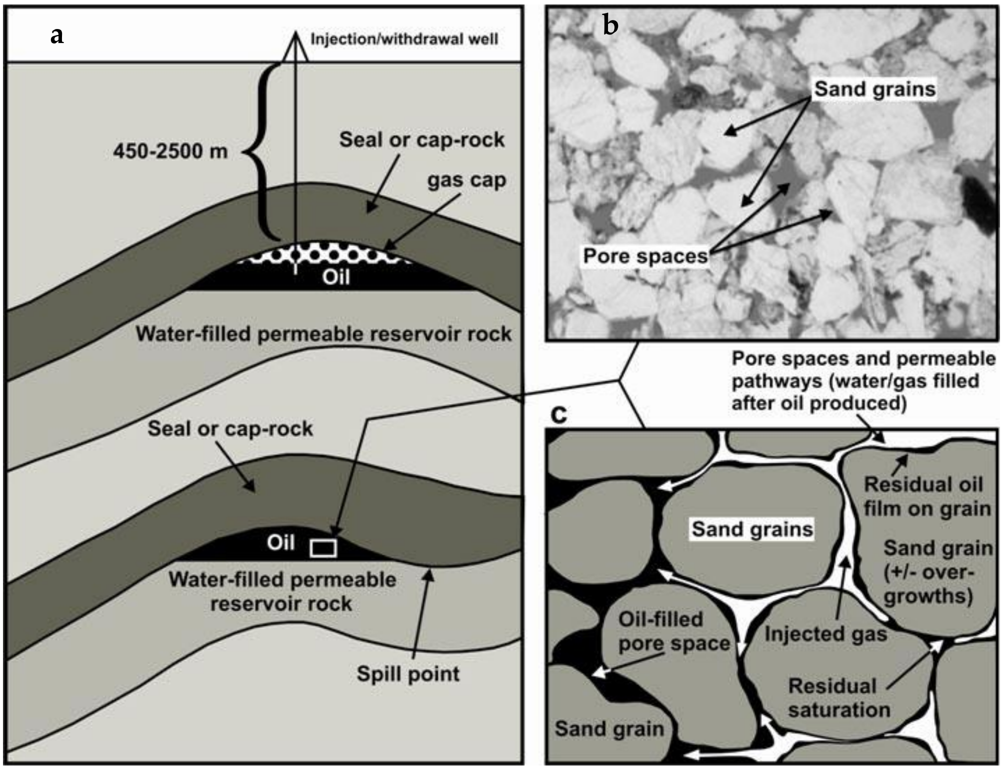

Figure 7. a) Overview of how reservoir depletes and is filled. b) Microscopic image of reservoir pores filled with oil c) Schematic of how injected hydrogen occupies and native gas (oil) evacuates pores [44]

The residual native gasses can be utilised to reduce cushion gas, granted no hydrogen depleting/contaminating reactions occur with injection[33]. This can reduce the required cushion gas to between 50-60% from the possible 80% required for aquifer storage[6, 21]. The multiphase-multicomponent interactions within these heterogeneous reservoirs enables mixing and thus necessitates post-storage separation processing to purify the contaminated hydrogen. As in aquifer storage, optimal depths for reservoirs reside approximately 2000m bgs, with greater depths providing a lower chance of methanogenic (MB) and sulphate reducing bacteria (SRB) being present due to temperature increases[22, 45]. Operating pressures for such systems are similar to aquifers, ranging between 100-400 bar to prevent intrusion of the evacuated water. These pressures, as with aquifer storage, are restricted by both the reservoir and caprock rock fracture pressures[21, 33, 36].

3.2. Challenges and Barriers

3.2.1. Salt Caverns

Although widely implemented across the world for natural gas storage, only four sites exist globally; three within Texas, USA - Clemens Dome, Spindlertop and Moss Bluff, and one in Teesside, UK[20]. The main benefits of salt cavern storage are its capacity for sealing and chemical inertness to hydrogen. Concomitantly, its deliverability rate and the multiple cycles per year also provide benefits[22]. This sealing capacity is accomplished through the cavern wall plastically deforming to prevent crack propagation[6].

The main constraint for salt caverns is their limited geographical availability compared to porous storage[46]. Other barriers/challenges of salt cavern storage are well known from natural gas storage. For instance: water management, formation of irregular caverns, and/or thermal and mechanical stability issues all contribute to the challenges associated with salt cavern storage.

3.2.1.1. Cavern Development

Problems incurred during the leaching and dissolution mining process can be categorised under resource management and process related challenges. The leaching process can be considered a convective mass transfer problem which is complicated by the moving boundaries, large volumes and long durations possible[47]. Low salinity water is required to provide effective dissolution of the salt into the extracted brine, creating a geographical constraint as access to a water source capable of providing quantities between 7-8 times that of the cavity volume are required[41]. On the other end of the development process, the extracted brine from the cavity requires management; mineral processing operations often utilise a closed loop system to save freshwater and comply with environmental regulations. However, with volumes in excess of 900,000m^3 – such as in the Spindlertop formation in Texas, USA – this may not be possible[20, 41].

The formation of irregular caverns is a process related challenge which brings about concerns of both safety (tightness and structural integrity) and effectiveness (reduction of capacity)[48]. Xue et al investigated mechanisms that could lead to the creation of these and determined three contributing factors: geological conditions, construction technology and tubing failures, with salt purity (heterogeneity) being a major contributor due to the increased interlayers[48].

3.2.1.2. Operation of Cavern

Challenges that arise during the cyclic loading of the cavern are considered operational challenges. This includes the effects from both mechanical and thermal loading from injection/withdrawal cycles and the effects these can take on the integrity of the surrounding formation. Habibi investigated the stability criteria required for both mechanical and thermal cyclic loading, stating that the fracture stress for the formation is a function of the rate of operation cycles[49]. This is exacerbated when fast cycles are considered, reducing the time increment in the changes in deviatoric stress (difference between internal pressure and geostatic stress)[49]. This suggests that although technically capable, the creep generated from ten cycles per year, may prevent such implementation. Furthermore, with increasing heterogeneity, additional deviatoric stresses between salt and other lithology need to be considered [50]. This is further complicated by mechanical properties varying on a case-by-case basis due to the environments in which the formation were formed, as well as sediment components, crystal geometries, content and distribution of impurities and tectonic histories[49]. Thermal stresses, induced through gas injection temperature, can result in microfracture development, a consequence of the tensile stress which it subjects the cavern wall to[49]. At an extreme state, in conjunction with over-pressuring, this can cause roof collapse within the cavern by inducing a tension state; hence, thermal variations of injected hydrogen must be considered during injection/withdrawal cycles[49].

3.2.2. Aquifers

The main benefit to aquifer storage is their offshore abundance and their substantially larger capacities. Lubon and Tarkowski estimate a potential 53,200 tonnes could be stored at one site; actual limitations are formation dependent and most probably exceed this[42]. Economically this technology may not be as attractive due to the uncertainty and expense of the site characterisation process. These expenses are associated with drilling operations that are necessary to determine if porosity and permeability of the reservoir/cap rock are adequate[22]. Hydrogen losses during operation are also of concern, such as migration along fault lines out-with the storage boundaries and losses occurring from thermophysical phenomena such as viscous fingering and upconing[22].

The challenges/barriers met in aquifer storage can be considered either developmental or operational. Developmental challenges consist of cost intensive processes such as, site characterisation and cushion gas reduction. Operational barriers consider more technical phenomena resulting from the variation in thermophysical properties between hydrogen and reservoir water. These include both viscous fingering and upconing. Operational barriers can affect a combination of injection rate and deliverability, quality and/or quantity of recoverable hydrogen, if not properly considered.

3.2.2.1. Site Characterisation

Estimated at approximately 20% of CAPEX by Lord et al., site characterisation encompasses both the drilling process and the assessment of the data acquired from this process[21]. This 20% was estimated for an inland formation (Yeso formation within the Estancia Basin, New Mexico), in the UK where offshore aquifers are the more likely option this will increase substantially. This creates an economic barrier/risk as there is no certainty that a site will be capable of storge prior to drilling. Although for new site exploration initial drilling is necessary to obtain core samples, 3D-printed cores could potentially be used to replicate samples of previous wells as a cost saving measure[51]. It is assumed that best practice for borehole drilling is already conducted due to the years of aquifer use in natural gas storage. Cost-reductive measures could be achieved by establishing an opensource data base of previous drill sites (similar to that constructed by BGS[46]), allowing for case development based off parameters provided.

3.2.2.2. *Cushion Gas Reduction*

With the cushion gas being potentially 45-80% of the volumetric capacity of the storage, and estimated to account for 52.4% of the cost by Lord et al., any means to reduce this would be beneficial[21]. Sainz-Garcia et al. presents the use of multiple shallow extraction wells, tactically positioned on the reservoir roof (caprock)[8]. This configuration allowed for recovery of up to 78% of the initial hydrogen injection[8]. Although successful for the Utrillas formation in the San Pedro dome, site specific data is necessary for accurate modelling[8]. Alternatively, Pfieiffer et al. suggest the use of nitrogen as a cushion gas, thereby reducing costs[8, 52]. The added complexity generated from gas mixing and additional costs for separation processes upon withdrawal would need to be factored in decision making[8].

3.2.2.3. *Viscous Fingering*

Viscous fingering is the unilateral displacement of a highly mobile fluid upon interacting with a sluggish native fluid[33]. Due to hydrogens high mobility ratio (estimated between 2-5[33]), a result of both its comparably low density and viscosity in relation to the saline water, the risk of viscous fingering and loss of hydrogen is considerable[33]. The result would be a reduction in recoverable hydrogen as lateral migration extends past the spill point of the plume [33]. To overcome both viscous fingering and the gravity override of the water phase, three methods are suggested: adjusting the injection rate, utilising a denser cushion gas and considering only deeply steeping anticline structures[8, 53, 54]. By reducing injection rates, the gravitational and capillary forces will override the acting viscous forces. This process can however result in several years for filling depending on site characteristics[33]. An alternative cushion gas during the developmental period would reduce the mobility ratios during the initial displacement of reservoir water, reducing the likelihood of fingers developing[54]. Sainz-Garcia et al. shows that the steeply dipping structure of the San Pedro dome provided an effective preventative measure[8].

3.2.2.4. *Upconing*

In addition to losses from viscous fingering, without alternative cushion gasses upconing is considered a major limitation in aquifers storage; with upwards of 90% of the withdrawn fluid being water[8, 42]. As withdrawal is initiated the pressure gradient between the water/hydrogen interface and the well is increased, creating an upwards migration of the water phase, mixing both phases[8]. The result of upconing is the withdrawal of hydrogen saturated with water, resulting in a more intensive separation process and potential well shutdown[8]. As with viscous fingering, an increased density and viscosity of the gas interface with the reservoir water could reduce this effect, thereby reducing the density gradient. Sainz-Garcia et al. determined that alternative well configurations, primarily focusing on higher extraction points, could also aid in reducing this[8].

3.2.3. *Depleted Oil/Gas Fields*

The main benefits to depleted oil/gas fields storage are the availability of pre-existing infrastructure, their geographical availability and their reduced cushion gas capacity (CGC)[22]. The use of existing infrastructure from the petrochemical industry contributes massively to it being estimated as the lowest costing technology analyzed by Lord et al.[21]. One pilot project "Underground Sun Storage" would imply this is possible, however, this is yet to be confirmed for high hydrogen content (projected utilizes 90%CH_4 10% H_2 blend)[55]. As such it still resides in the modelling stage of development.

Challenges/barriers faced by depleted oil/gas fields are similar to that of aquifers, due to both utilising porous storage mechanisms. These challenges can again be separated into developmental and operational challenges, the former consisting of the repurposing of current infrastructure while the latter is concerned with multiphase-multicomponent nature of the reservoir and problems that arise from this.

3.2.3.1. Repurposing of Infrastructure

The problems with repurposing equipment for hydrogen can be categorised into three forms: creation of internal flaws or blusters, hydride formation and steel embrittlement[56, 57]. Low and high alloy steels, plain carbon steels and stainless steels are examples of common materials used within the oil and gas sector which are at risk of exposure to hydrogen failure mechanisms[58]. Onshore the UK is conducting investigations into safety concerns and assessing gas losses with projects such as H21 Leeds city gate (*Northern Gas Networks)* and the proposed FutureGrid (*National Grid*))[34, 59]. H21 Leeds City Gate is a project undertaken by *Northern Gas Networks*, wherein demonstration of hydrogen usage throughout a purpose-built household is being conducted[34]. The second phase being the testing of previously used natural gas infrastructure with pure hydrogen and the development of a microgrid to do such [34]. Offshore repurposing creates additional challenges as the extremely corrosive environments that the equipment will be exposed to need to be considered in order to understand the accelerated degradation that would likely occur[58]. The "Underground Sun Storage" project has provided promising results at low hydrogen content, suggesting no negative effect on the facility[55]. Other than hydrogen induced problems, infrastructure corrosion of both surface level and subsurface will require assessment.

3.2.3.2. Multiphase-Multicomponent Mixing

The multicomponent-multiphase mixing within the reservoir is a product of thermo-hydro-mechanical-chemical processes and is heavily influenced by fluid velocity/injection pressure[33]. Although no direct mixing is intended, the porous nature of the reservoir and the flow of fluid through it induces mixing known as mechanical dispersion[33]. Additional mixing from molecular diffusion stems from the component concentration gradients. This can occur independent of advective/convective transport and is therefore a primary concern during idle periods[33]. The results of this mixing can be a heavily contaminated extracted product, generating additional costs for necessary separation processes. The degree of this mixing requires accurate model descriptions simulating thermo-hydro-mechanical-chemical processes and are thus the current focus of many research groups*[33, 42, 52, 60]*. "HyStorPor" is the UK's current program funded by the *EPSRC* conducted at *The University of Edinburgh* with the goal of investigating this at lab scale and the development of flow modelling approach at the utility-scale[61].

3.3. Geological Criteria

3.3.1. Salt Caverns

The selection of candidate host rock can be split into two sections: geological and geographical. The identification of candidate host rocks initiates with determining the type of formation. In Allen, Doherty and Thom's paper investigating geotechnical factors of compressed air energy storage within salt caverns, four features that suggest that dome formations are preferential to bedded formations are provided[62];

- Large deposits at relatively shallow depths
- Nearly homogenous lithology, 95% halite (reduced chance of contamination)
- Imperviousness to stagnant ground water
- Chemical compatibility with injected gas

To build on this, bedded salt formations provide a greater likelihood of embedded non-soluble materials such as dolomite, anhydrite and shale, a result of higher heterogeneity in their lithology[21]. There is no apparent reason this criterion would alter for hydrogen storage. Another negative to bedded salt formations is the operational pressure, which is limited by the fracture pressure of the weakest lithology within the formation, the minimum pressure to prevent roof creep and instability, and the maximum threshold pressures that could induce bedding plane slip[21, 63]. This reduced operational pressure correlates to lower attainable capacities for identical storage volumes. These opinions are consistent with the currently installed salt cavern storage, not including the Teesside facility, as each of the three out of four installed globally use salt dome formations[64].

Generally, these domes (elongated) salt formations are several hundred of metres in depth and tens of meters in diameter and can vary from 150,000-800,000m^3[6, 22]. As to the depth of these formations, Matos et al. states that between 1500-2000m bgs is ideal as the stability of salt at these depths is desirable, providing a reduced chance of leakage[65]. Lord et al. suggests that any deeper than such would not be advantageous as increased pressures and temperature, accompanied by reduced stability, would make it difficult to maintain[63]. Allen et al. suggests that a minimum of 600m depth to the roof of the cavern and optimal depth at 800m; while Bauer suggests a range from 500-1500m would be appropriate[62, 66]. However, of the four operational caverns in the world, the Teesside site in the UK operates at a depth just below 300m bgs, showing that the storage be accomplished at shallower depths, albeit at reduced capacities[67].

A framework utilising an analytical hierarchy process (AHP) was established by Lewandowska-Śmierzchalska et al. and was used to assess hydrogen storage sites in Poland[68]. Lewandowska-Śmierzchalska et al. determined that factors and their weighing were: reservoir lithology (33.2%), stage of exploration (32.1%), type of salt deposit (12.2%), reservoir volume (10.2%), depth of reservoir (6.3%) and geothermal gradient (6%)[68]. The importance of a homogenous lithology is signified through this AHP approach. Not only can heterogeneity restrict operational pressure, but embedded impurities can result in hydrogen consumption/contamination [68].

3.3.1.1. Biogeochemical Reactions

Although salt is chemically inert to hydrogen, the potential impurities embedded in the formation may not be and can result in a reduced quality and/or quantity of hydrogen. The most common forms of impurities being Ca^{+2}, Fe^{+2} , Fe^{+3} , Mg^{+2} , K^{+}, Cl^{-}, CO_3^{-2} 3 , and SO_4^{-2}[64]. $CaSO_4$ - also known as anhydrite – is highly hydroscopic, reacting with calcium sulphate dihydrate in the process of which small amounts of both SO_4^{2-} and Ca_4^{2+} are formed (which in the presence of hydrogen can create hydrogen sulfide, a toxic and corrosive gas contaminating the supply)[64, 69].

3.3.2. Aquifers

One of the key benefits to aquifer storage is the availability of formations, albeit at varying hydraulic conductivities[46]. When determining the effectiveness of an aquifer two parts need to be considered, the aquifer itself and the caprock (aquitard), each having opposing requirements. Where an aquifer requires high porosity and permeability to enable the flow of hydrogen into the formation's pores, the aquitard requires considerably lower permeability and porosity to prevent such flow and reduce hydrogen diffusion out with the boundaries[22, 70]. Homogeneity within these layers is preferential to reduce the complexity and provide even distribution of injected gas, as well as ensuring the absence of any gas permeable fault lines.

Tarkowski and Matos et al. both suggest formations utilised should be in the region of 500-2000m bgs[6, 22]. However, systems modelled by Sainz-Garcia et al., Pfeiffer et al. and Pfeiffer and Bauer focus on the sections between 450-700m below surface[8, 54, 60]. Although these modelled reservoirs provide valuable insight, candidate reservoirs would most likely be in the >1500m bgs to allow for hydrogen to be stored at a meaningful density. By increasing the depth, higher pressures can be utilised due to the higher *in situ* pressure generated by the overburden, allowing for larger capacities. However, a steep anticline structure is required to prevent lateral migration beyond the spill point which can act as a limitation on depth.

On top of these general requirements, candidate host rock is surveyed prior to construction to determine characteristics such as, reservoir rock permeability, sealing capacity of the caprock and the presence of biochemical reactors.

3.3.2.1. *Permeability of Reservoir Rock*

The intrinsic permeability of the reservoir rock is a property solely based on the characteristics of the formation; this is determined through *Darcy's Law*. *Equation 4* shows how this is determined under ideal conditions.

$$k = C * {d_m}^2 \qquad [4]$$

Where k represents the intrinsic permeability, d_m is the mean diameter of grain size and C is a constant of proportionality. Under real conditions C would consider other characteristics from the porous formation such as, distribution of grain size, the sphericity and roundness of grains and the nature in which they are packed[70]. Further complexities arise when assessing heterogeneous reservoirs with multiphase interactions, as relative permeability and capillary pressure require consideration[71]. The permeability and the capillary pressure of the reservoir rock determines factors such as the injection/withdrawal rates, storage capacity and gas mixing effects (i.e. mechanical dispersion)[52]. With increased permeability comes higher injection/withdrawal rates; however, this is still constrained by the occurrence of thermophysical phenomena (i.e. viscous fingering and upconing).

3.3.2.2. *Caprock Sealing Capacity*

Unlike depleted oil/gas deposits, where a degree of tightness is already assured due to the previously trapped gas, aquifers require extensive assessment[22]. Assuming a suitable trap structure, the sealing capacity of the caprock in a porous formation can be reduced to two factors: the permeability of the caprock and the occurrence of fault lines through this layer.

To prevent gas leakage through the caprock a considerably low – if not totally – impermeable stratum is required; this typically occurs as either salt rock, clay stone, shale or carbonate rocks[6]. Due to the higher operating pressures required to meet similar storage capacities, a low permeability stratum is required to mitigate any diffusion of hydrogen through the caprock.

Aside from regular diffusive losses, seismic factors such as fault lines can create preferential channels for migration from the reservoir to the overburden[68]. This can come in the form of undetected faults or as a consequence of recent seismic activity[22]. Fortunately, the UK has comparably inactive seismic activity relative to other parts of the world. However, neglecting to consider existing fault lines could result in a higher amount of unrecoverable hydrogen[46]. The best way to combat this is to utilise aquifers located within tectonic-traps, in steep domes to allow for the recovering of high quality H_2[72]. Although this requires additional surveying, and thus increases the cost, information on fault lines where these structures may occur is available[21, 46].

3.3.2.3. Biogeochemical reactions

During the surveying period of assessing the proposed aquifer, ensuring there is no hydrogen consuming/contaminating bacteria present within the formation is essential. Methanogenic bacteria and sulphate reducing bacteria (SRB) can have an impact to the point where an aquifer is considered unusable[45]. Both forms of bacteria consume hydrogen, however, methanogenic bacteria relies on CO_2 and is limited by its supply, meaning formations can still be utilised (depending on the concentration) if present[36]. If SRB's are discovered, in the absence of desulphurisation equipment, Amid et al. suggests that development should not proceed due to the substantially increased costs[36].

3.3.3. *Depleted Oil/Gas Fields*

Depleted oil/gas fields require identical conditions to that of aquifers. In contrast to aquifer storage, the characterisation process is less laborious as reservoirs have already been assessed by the petrochemical industry. However, as oil/gas is not as easily dispersed as hydrogen, trap formation should be reviewed with preference given to steep anticline structures preventing lateral dispersion[8]. Caprock tightness is often assumed due to the storage of native gasses over a geological time frame. This assumption is not assured as hydrogens molecular, thermophysical and interfacial properties vary greatly to oil/gas[73].

The required depth of these anticline structures is similar to aquifer storage, with up to 2000m bgs being considered sufficient[7, 22]. However, Amid et al. investigated the use of the rough gas storage facility, a reservoir located 2743m bgs[36]. These increased depths would allow for considerably higher capacity, as well as benefiting from the greater sealing and tightness associated with them, due to the generally decreased fracture and rock permeability[74].

Lewandowska-Śmierzchalska et al. presents factors and their weighting in assessment of potential reservoirs: overburden rock lithology (36.74%), tectonic activity (24.09%), deposit form (oil or gas) (15.98%), pore volume of reservoir (13.11%), depth of reservoir (5.90%) and stage of exploration (4.99%)[68]. The reduced weighing of tectonic activity (in comparison to aquifer storage) can be seen to stem from the storage of the native gasses over a geological period. In addition to this, under "deposit form" the selection criteria showed preference for natural gas reservoirs, presumably for their reduced cushion gas and more gradual density gradient[68]. Other considerations in assessment of geological formations involve, the presence of hydrogen consuming bacteria and the caprock tightness.

3.3.3.1. Methanogenic and Sulphate Reducing Bacteria

It is know from the petrochemical industry that both methanogenic bacteria and SRB – such as that of the Archaea domain – are capable of living within the naturally occurring reservoir[45]. The methanogenesis process mentioned briefly in *3.3.2.3* consumes both carbon dioxide and hydrogen to produce methane and water. A modelling study conducted by Amid et al. using *Phreeqc* determined that, in the presence of specified methanogenic bacteria, losses were restricted to 3.7% of volume, due to drainage of available CO_2[36]. This suggests that if CO_2 were implemented as a cushion gas this would increase exponentially. In addition to this, Amid et al. discusses how this could result in a reduction of pressure and hence, the recoverable amount of available hydrogen[36].

Other biogeochemical reactions that could reduce both the quality and quantity of hydrogen are that produced by SRB. The problem with SRB is threefold: as the sulphide created has a high toxicity for humans, erodes steel material used for structural purposes and can lessen the quality of hydrogen withdrawn from the reservoir[45]. These problems manifest primarily in two forms: mesophilic SRB, which are responsible for the corrosive nature in top facilities and thermophilic SRB, which are responsible for *in situ* reservoir souring (the main concern for hydrogen storage)[45]. As the prevalence of these bacteria is dependent on suitably high temperatures, deeper reservoirs are preferential for storage; again reaffirming the benefits of utilising deep geological features[45]. The avoidance of reservoirs rocks cemented with either anhydrite or gypsum is also recommended as these provide favourable characteristics for SRB growth[42]. Concomitantly, fluid/rock reactions – primarily hydrogen-driven redox reactions with iron bearing minerals – also cause concern, potentially influencing mechanical stability[75, 76]. Most of these reactions are anticipated to be negligible at low temperatures, with the exception of pyrite reduction to pyrrhotite. More information on this can be found in.

3.3.3.2. Caprock Tightness

Although a level of tightness is assured from gas storage over a geological timescale, the degree of which this tightness is not certain due to varying fluid properties. In a study into the site characterisation for CO_2 storage within a depleted oil reservoir, conducted by Li et al., it was found that the interfacial tension between CO_2/H_2O and oil/H_2O was significantly reduced[73]. The interfacial tension (IFT) can be defined as the cohesive energy present at an interface between two molecules stemming from an imbalance of forces between said molecules at the interface[77]. The result on this reduction in IFT is an increased rate of migration to the caprock interface, and hence, it is described as "crucial" in evaluation of the reservoirs repurposing[73]. With hydrogen being a more buoyant fluid than CO_2 this could potentially have a greater impact. To produce an accurate description of interfacial properties, other parameters such as, contact angle, the wettability and capillary pressure within the pores need to be considered[77]. In addition to this, the salinity of reservoir water can alter the IFT and hence, should also be considered in models[77].

3.4. Geographical Availability

When considering large scale hydrogen "play opportunities" the selection can be split into either onshore or offshore. Onshore storage offers reduced costs, but local safety concerns could create barriers. Conversely, offshore storage offers larger capacities with little sociological impact at considerable cost[74].

3.4.1. Onshore Opportunities

Of the papers reviewed, each one reinforces the importance of the geographical location when determining adequate storage site. Several key components and considerations include, but are not limited to, the local geology of the site, structural and tectonic factors, seismicity risks, hydrogeological and geothermal issues, geotechnical factors, demand location and right-of-way considerations for pipelines [6, 21, 22]. The correct selection of which will provide a more economically appealing system with an increased value in the supply chain. To provide a more meaningful presentation of onshore play opportunities (potential storage sites[74]), both the onshore wind farms (hydrogen production system) and the national transmission system (NTS) (possible delivery system) have been included in *Figure 8*, allowing for consideration of the supply chain to such storage sites.

From *Figure 8b* the lack of geographical availability can be viewed as an impeding factor for deployment of salt cavern storage across the UK. Although a mature technology, salt features reside exclusively within England (both north-east and sporadically down the west), constraining implementation within Scotland – a country that may rely on hydrogen more heavily for heating. If repurposed, this problem could be mitigated through utilising the NTS for delivery. However, additional efficiency losses will occur due to the higher pressurisation required. Building on the necessity for energy storage within Scotland, although generated in 2014, *Figure 8a* shows the distribution of onshore windfarms residing predominantly in Scotland. This is further confirmed with Scotland occupying a 59% share of installed capacity in 2019[78, 79]. Although this problem may seem localised to both Scotland and Northern Ireland, the volume of salt formations may not be capable to withhold the capacity required in a net-zero transition (minimum 15TWh) without sacrificing structural integrity[2]. This facilitates the exploration of porous storage options.

In addition to the salt formations being visible in *Figure 8b* the local aquifer and conductivity can be seen[46]. Although aquifers are available throughout the UK, unsuitable characteristics (depth of reservoirs), cultural constraints (i.e. public perception) and ensuring the integrity of potable water – such as the southern chalk group[46]– prevents the utilisation of these reservoirs[80]. However, one play opportunity proposed by Heinemann et al. is presented in *Figure 8c* within the midland valley; a porous formation bound to the north by the Highland Boundary Fault and to the south by the Southern Upland Fault[74]. Although considered to be of medium capacity (≈2000-3000 tonnes H_2), the colocation of the proposed play with both the NTS and wind capacity suggests that a seasonal storage site of green hydrogen could be utilised, providing peak shaving of demand for both Edinburgh and Glasgow[74].

Onshore hydrogen storage could provide an integral part in the development of porous storage, providing a cheap potential for developing demonstration projects. However, for sizeable capacities offshore systems must be explored. Additionally, with the offshore wind capacity assured to over triple (from Q2 2020) to 40GW by 2030, and the inherent wastage of renewable capacity presented, offshore production and storage of hydrogen within depleted oil/gas reservoirs or deep saline aquifers could provide a solution[1, 26].

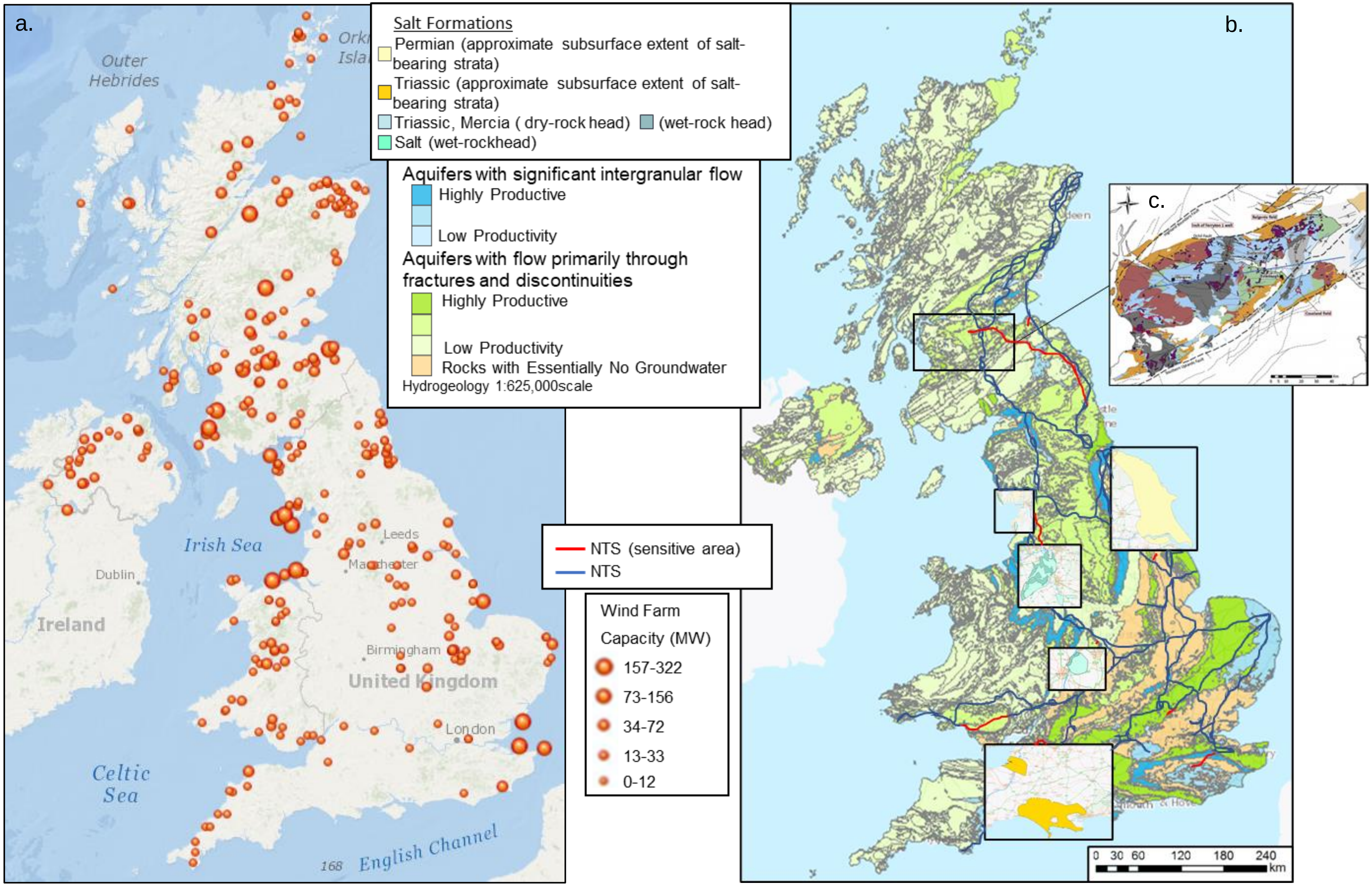

Figure 8 a) Map of onshore wind farms and their respective capacities as of 2014[79]. b) Map of onshore aquifers, salt features and national transmission system (NTS)[39, 46]. c) Proposed aquifer site for hydrogen storage by Heinemann et al [74]

3.4.2. Offshore Opportunities

By utilizing offshore geological formations sociological concerns which could hinder onshore development can be avoided. This comes with a substantial increase in cost in developing infrastructure[74]. However, these costs can be reduced through repurposing of offshore hydrocarbon well sites. The first repurposing of such for offshore green hydrogen production on a disused oil/gas platform is set to be in operation in 2021[81]. *Figure 9a* presents both confined deep saline aquifers and depleted oil/gas fields which could potentially be utilized for storage. In addition to that presented in *Figure 8*, the planned wind farms are displayed in *Figure 9a*, while *Figure 9b* presents the offshore oil/gas infrastructure including platforms and pipelines[82].

When considering offshore storage depleted oil/gas fields have a distinctive advantage over aquifers; this being that prospective sites are already identifiable based off previous petrochemical usage (*Figure 9b*). From *Figure 9a* aquifers containing depleted oil/gas fields can be seen to be well situated within England amongst an area planned for considerable wind farm development under *The Crown Estate Leasing Round 4*, as well as pipelines which could provide delivery. Comparing this with onshore availability (see *Figure 8b*), this comes in an area less populated with salt caverns, where the main aquifer is utilized as a primary water supply source[46]. Additionally, as shown in *Figure 9b* both the *Interconnector* and the *BBL* pipelines, connect the UK to Belgium and the Netherlands respectively. The proximity of these to storage sites could provide benefits if adapted for hydrogen exportation in the future.

The *Scotwind Leasing*, representing most planned turbines around Scotland, tend to align more with the saline aquifers; however, they are within reasonable distance to depleted oil/gas deposits. As expected, the NTS aligns well with these points due to it being the main form of transporting the previously stored native gasses within the depleted gas fields. One proposed hydrogen storage site by Amid et al. can be seen in the Mideast, the previously used Rough Gas Storage Facility[36]. The benefits to this repurposing would be alignment with cluster of lower capacity farms as well as the Hornsea project, which upon completion of phase four will be expanded to 6004MW, roughly a quarter of current wind capacity[83, 84]. The proposed play opportunity could provide large storage capacities at the immediate point of production of green hydrogen. This is within reasonable distance of Yorkshire salt deposits as can be seen in *Figure 8*a and thus will depend on functional purpose and economic factors. In the recent publication by Mouli-Costillo et al., offshore gas reservoirs off the coast of the UK were mapped and assessed for hydrogen storage[85]. Mouli-Costillo et al. calculates through a box conversion a potential 2661.9TWh of hydrogen could be stored off the coast of the UK[85]. It is further suggested that aquifers in this region could potentially surpass this is capacity; however, measuring such is made difficult through unavailable information[85].

Both onshore and offshore play opportunities need to be considered when determining the hydrogen grid required to meet net-zero, taking into consideration both deliverability and storage period requirements.

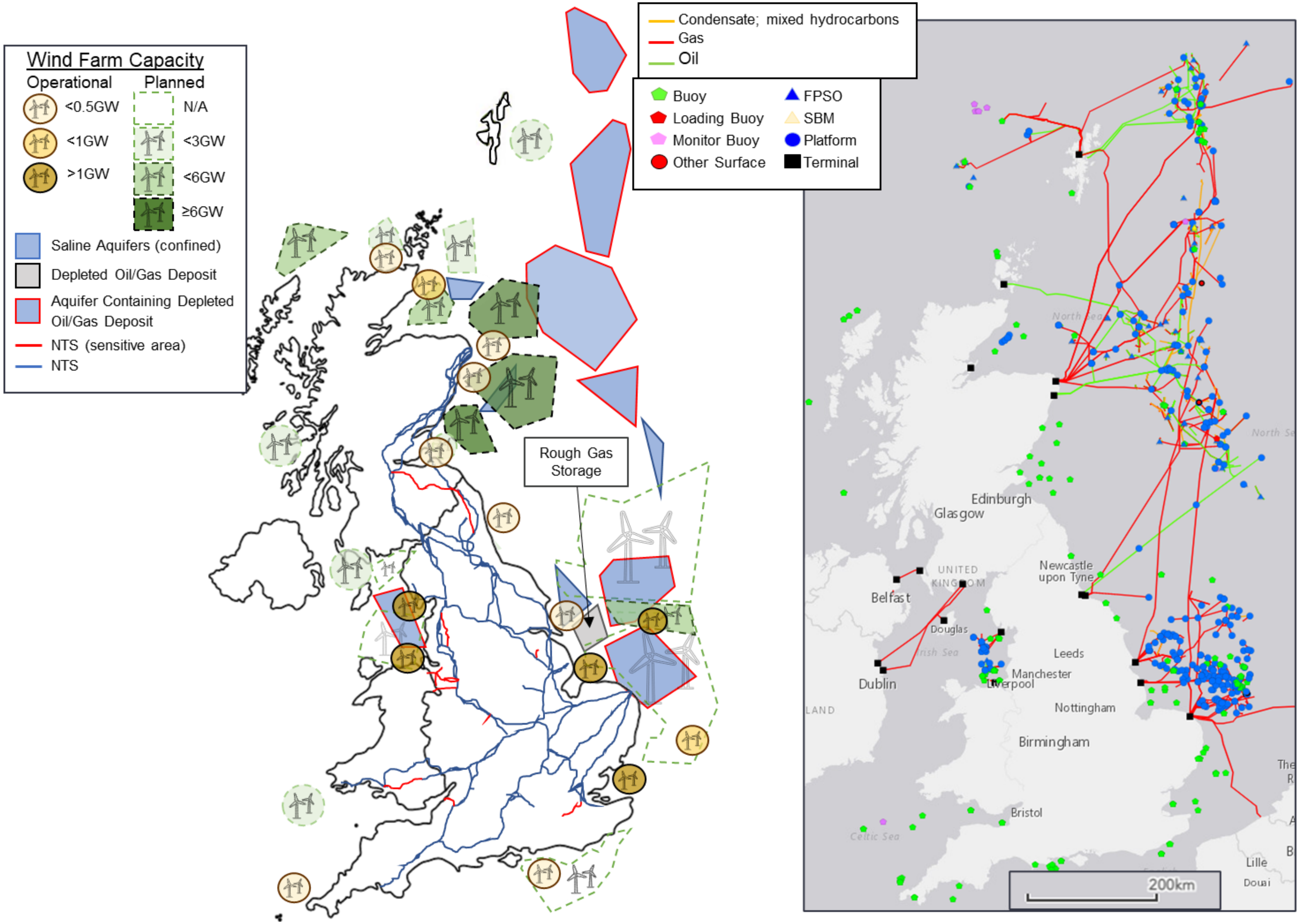

Figure 9. a) Map of the UK displaying operational and planned wind farms, confined aquifers, depleted oil/gas fields and the NTS[39, 83, 86] b) Offshore oil and gas infrastructure, lines representing pipelines and points representing surface infrastructure, FPSO – Floating Production and Storage Offshore, SBM – Synthetic-based Mud [82]

3.5. Cost

Costs of storage systems will vary on a case-by-case basis. Broadly speaking the various sources of CAPEX for subsurface storage technologies can be interpreted through the modelling results of Lord et al., who utilised the Hydrogen Geologic Storage Model (H2GSM) framework (*Figure 10*)[21].

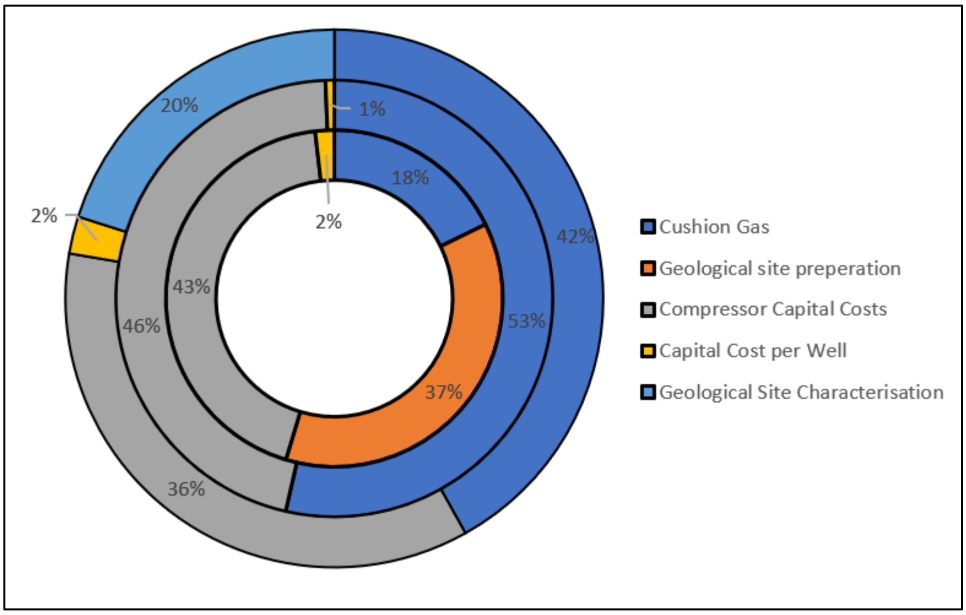

Figure 10. Various sources of CAPEX for subsurface storage technologies, from outwards moving in, aquifer, depleted oil/gas deposit and salt cavern[21]

3.5.1. Salt Cavern

One of the main impeding factors for deployment is both the capital and operational expenditure, at the surface and subsurface levels. Capital costs at surface level include gas compression equipment and building construction, whereas subsurface considers cavity development processes such as leaching and well development; cushion gas can also be considered within this category as it is unrecoverable[21]. The estimated share in capital expenditure for these variables can be seen in *Figure 10*. How these factors interrelate to each other is primarily governed by the depth of the storage. With reduced depth comes a lower injection pressure, reducing the load of compression equipment as well as the costs, at the necessary expense of a reduced storage capacity. By increasing the depth, larger capacities for hydrogen storage and lower requirements for cushion gas can be obtained[6]. A possible means of reduction would be an alternative (denser) cushion gas; gravitational sedimentation (assuming a sufficient idle period) would allow for the less dense hydrogen to be extracted from the top of the reservoir. This would however be subject to a degree of the upconing process as in porous reservoir storage. Unfortunately, deeper storage cavities are at a greater risk of foreclosure due to temperature variations and overburden pressure[6]. As with any technology these costs are not static, additional factors influencing costs include the number of boreholes, geographical location, cushion gas requirements and material costs[21]

As hydrogen production is out-with the scope of this paper; operational cost considered would only be that of further compression required for injection, maintenance and post-storage processing (information on production from various methods costs can be found in

[87-91]). As post-storage processing is a requirement due to residual water from the leaching process and insoluble impurities contaminating the hydrogen supply, the degree of post-storage processing would be dependent on the quality required for its purpose.

3.5.2. Aquifer

Lord et al. suggests that aquifer storage could provide a medium between depleted oil/gas deposits and salt caverns[21]. Alternatively, Tarkowski anticipates that due to the characterisation period this would be the most expensive subsurface system[22]. *Table 1* presents both the capital and operational costs with aquifer storage.

Table 1 Table of CAPEX and OP&M costs for aquifer storage of hydrogen

Capital Expenditure	Operational & Maintenance Costs
Above-ground Infrastructure Cushion Gas Geological Surveying Compressors Pipelines & Wells	Viscous Fingering Leakage from Wells Pipelines and Wells Hydrogen Compression Compressor maintenance Post-Storage Processing

Of the capital costs, the main contributor is anticipated to be the cushion gas, accounting for 42% of the total CAPEX; even when assuming a 1:1 WGC:CGC [21]. Methods in natural gas storage include the use of alternative gasses, including CO_2 and N_2; however, use of CO_2 would increase the supply available to any methanogenic bacteria and could risk greater hydrogen consumption. Based on the estimated costs of nitrogen alone >\$1.89/m^3 (if only 1200m^3 are required a month), for identical mass requirements this cuts the cost by more than a third compared to that used by Lord et al. [92, 93]. Alternatively, by utilising multiple extraction wells and various configurations the recoverable amount of hydrogen can be increased, as was accomplished by Sainz-Garcia et al.[8]. Concomitantly, this allows for a less intensive separation process as less native fluids are extracted.

Other than compressor equipment, which is out-with the scope of this study (more can be found in on its development in [94-96]), the characterisation process occupies the next largest share (see *Figure 10*). Site characterisations consider the drilling of explorative wells to determine geological characteristics and the assessment of such for storage. The surveying period is necessary to provide information on porosity, intrinsic permeability and the capillary entry pressure to allow for reservoir properties such as deliverability and capacity to be determined[21, 22]. Unfortunately, this is an unavoidable cost for new exploration.

Operational costs during aquifer storage can occur from either loss of hydrogen, compression equipment or post-storage processing. Post-storage processing considers both the dehydration of the hydrogen (which can be substantial[42]) as well as separation from other gasses utilised or produced through biological processes. One such method to add value, suggested by Court et al. for CO_2 storage, is the additional desalination of the extracted saline water (in water stressed regions) to provide use in either industry, agriculture or domestic applications[97]. Desalination is a cost intensive process which may be necessary if offshore production/storage is necessary.

3.5.3. Depleted Oil/Gas Fields

Lord et al. estimates that a cost saving of 4.7% and 23.6% from aquifer and salt cavern storage respectively could be attained with depleted oil/gas deposit storage[21]. These estimations were based on no site characterisation costs, assuming gas tightness of prospective reservoirs due to gas being trapped over a geological time period[21]. Although not as extensive as aquifer storage (as previous data is available from petrochemical industry), site characterisation is still required and costs will incur given the higher mobility of hydrogen gas than oil and natural gas[21, 74].

Possibly the main capital cost saving mechanism, of which is still uncertain, is the repurposing of current petrochemical infrastructure which (for offshore purposes) could save between \$200m-\$600m per site[98]. Additionally, the "plug and abandonment" project operating is estimated to cost the UK £48bn as well as the substantial job losses from these platforms[99]. In addition to this, rather than utilising native gasses to reduce cushion gas, the cushion gas can be injected at one end, creating a sweeping motion to allow for additional oil/natural gas recovery, generating value from what would initially be considered a loss[33]. In comparison to aquifer storage, the only additional operational costs would be more intensive separation processing due to native oil/gas and management of this by-product.

3.6. Comparison of Storage Technologies

Table 2 provides a comparison of the various storage technologies. Although *Table 2* suggests a higher deliverability was available for depleted oil/gas deposits, this value was based on the storage capacity over a set drainage period[36]. As a result of not having to consider inertia forces from viscous fluids, injection rates and withdrawal rates are greater for salt caverns. Feldmann et al. suggested a filling period of several years could be required to prevent viscous fingering occurring. This is however formation dependent and not conducive of all reservoirs[33]. Additionally, salt cavern storage can provide a higher number of cycles than both porous storage mechanisms, allowing for more flexibility as a storage system.

The capacity of deep aquifer storage is capable of an order of magnitude greater than that of salt caverns. It should be noted that real values were used for salt caverns, while data for porous storage stemmed primarily from numerical models [20, 42]. However, at identical capacities, in a worst-case scenario, aquifer storage could potentially require four times the cushion gas as that of salt cavern storage[21].

Few economic analyses have been conducted on utility-scale storage, with most including the entire supply chain. Lord et al. provides a storage-specific analysis[21], determining that although capable of higher deliverability, the development costs (leaching) of salt cavern storage makes it more expensive than porous forms; this was reinforced by Lepszy et al. determining a near identical cost[100]. Depleted oil/gas deposits have been suggested to be the cheapest, although the assumptions made in the study involve the use of previous petrochemical equipment and no site characterisation cost being considered[21]. This estimate also makes use of inland (onshore) reservoirs, which as mentioned in *section 3.4.* is not likely within the UK. Although costs play a major role in selection, the geographic availability takes precedence over this.

To reiterate the sentiments of *section 3.4.*, salt cavern storage across the north and south east of the UK is constrained by availability in these regions. Aquifers are considerably more accessible, however, onshore potable water should be protected from potential contamination[80]. Both deep saline aquifers and depleted oil/gas fields provided substantial availability offshore (see *Figure 9*), situated in points of great green hydrogen potential, as well as areas where onshore caverns are unavailable.

Table 2. Different utility-scale subsurface storage and aspects considered during decision making

	Salt Cavern	Aquifer	Depleted Oil/Gas Fields
Point in development	Commercial	Laboratory	Laboratory
No. injection/ withdrawal cycles	Up to 10 [22]	1-2 [22]	1-2 [22]
Capacity (tonnes H_2)	Small – Medium 1,000-3,500[20, 34]	Large – Very Large 7200-53,000 [21, 42]	Medium – Large 2,000-23000 [33, 74]
Cushion gas Requirements	20-33% [6]	45-80[6, 21, 36]	50-60[6]
Operating Pressure (bar)	45-202[20]	30-137.8 [42, 52]	100-400 [33, 36]
Discharge Rate (GW/day)	0.467-10.128[100]	1.09-8.55 [8, 42, 52]	2.66-100 [33, 36]
Geographical Availability (UK)	Onshore – Exclusive to England [46]	Offshore Available Across UK [46, 86]	Offshore Available Across UK [82, 85, 86]
Cost ($/kg$H_2$)	1.60-1.61 [21, 100]	1.29 [21]	1.23-1.48 [21, 71]

Moving forward, all aspects presented in *Table 2* must be considered, with geographical availability being the main factor. Additionally, the sociological concerns of onshore sites such as public opinion and impact to daily life need to be considered. It is anticipated that the development of porous storage will be essential in meeting storage demands. However, to provide a flexible 15TWh of storage both porous and salt cavern storage will be necessary.

4. Current and Future Research

4.1. Salt Cavern

4.1.1. Data Gathering

As there are only a few operational salt cavern facilities, real data provided from these could prove to be beneficial in providing more accurate model descriptions, potentially reducing the cost in the site characterisation process. Some methods suggested to do this include; geological surveys, periodical surveys during operation and establishing a geological database [22]. Through completing geological surveys of prospective formations and assessing their worth as not only a storage facility but their value in the supply chain, case can be developed to incentivise industry. Through conducting periodical surveys on existing caverns, investigating the effects of cyclic loading on cavern formation, optimisation of cycle times and withdrawal rates can be accomplished, and limits established. By establishing a geological and geographical database that includes key features such as gas network pipelines and potential sites for both green and blue hydrogen production, case studies can be developed for regional supplies such as those conducted by *ATKINS*[67].

4.1.2. Numerical Simulation

There are several models in the literature developed for natural gas storage within salt caverns, with more recent simulations being directed towards bedded and horizontal formations[102-104]. Models of hydrogen storage are not as readily available. Gabrielli et al. outlines how fundamentally the mechanisms in which hydrogen is transported is mainly unchanged, with the additional concern of a potentially increase gas flux into/out of the cavern wall due to its molecular size[105]. Gabriel et al. then determined this to have little practical implications allowing for a tank model to be used when utilising a mixed integer linear program optimization framework[105]. A basic cylindrical model was used, which some may consider an oversimplification of the cavern's geometry. Additionally, several assumptions were made to optimize this model, such as thermodynamic and transport properties being taken to be independent of pressure and it being assumed that there is no moisture in the cavern. However, the results held true to the more detailed model[105]. Böttcher et al.'s use of opensource software OpenGeoSys provides insight into thermo-mechanical effects of short cycles on the cavern walls due to cyclic loading [106]. Through simulation of 90 full cycles annually, Böttcher et al. was able to deduce that capacity would be reduced due to creep deformation[106]. This work could be furthered by incorporating cyclic fatigue within the material model. Passaris and Yfantis also conducted a thermo-mechanical investigation utilising a three-dimensional axis-symmetric model[107]. The model found that the distribution of the von Mises stress was restricted to 0.6m into the salt mass and, although subjected to moderate shear stress, cavern integrity remained unaltered after six years of operation[107]. This model does however implement a static deformation model for the vertical walls; allowing for further works by developing a dynamic model. Each model mentioned assumes a homogeneous lithology with isotropic material properties. By extending this to consider heterogeneities (impurities) within the formation/cavern wall, non-ideal scenarios can be investigated. Furthermore, the incorporation of the hydrodynamics during filling and chemical reactions that may occur would prove to be a more robust model description. As four caverns operate globally it cannot be assumed that sufficient models have been established.

4.2. Porous Storage

As porous storage will be essential in delivering net-zero for the UK, a more in-depth review of current research is presented. Focus is primarily given to simulation process as this is the current stage of development, other avenues have already been presented in *section 3.2* . To gain a critical understanding of porous storage, numerical models have been developed to consider a combination of four different processes;: thermodynamic, hydrodynamic, geo-mechanical and biogeochemical (THMC).

4.2.1. Current Research

4.2.1.1. Numerical Models

A wide array of professional reservoir simulation software exists for the petrochemical industry, some of which, *ECLIPSE* and *TOUGH*, have been used for hydrogen simulation. In addition to this *DuMu^x^*, *COMSOL* and *OpenGeoSys-ECLIPSE* have also been implemented. One common assumption made through all models is that of an impermeable caprock, to reduce complexities in the simulation.

ECLIPSE-E300 is part of the *ECLIPSE* software package for compositional flow, licensed by ©Schlumberger, capable of two-phase immiscible flow while modelling temperature dependent diffusion of both gas components into the water phase[52, 108]. Eclipse – E300 has been utilised in two publications of hydrogen storage within aquifers, first by Pfeiffer and Baur and more recently by Pfeiffer et al.[52, 54]. In Pfeiffer et al.'s recent publication a heterogenous model of the Middle Rhaetian deposit of the north German Basin was investigated[52]. The model framework allowed for effective representation of hydrodynamic processes associated with reservoir storage, with the outcome determining a recovered fluid composition ranging from 0.8-0.3 (molar fraction) by the end of withdrawal[52]. However, several aspects could be improved upon such as the adoption of a Neumann boundary condition, creating a hydraulically closed domain about each boundary. Realistically, these systems are not closed domains and the pressure response would vary to that displayed. Additionally, although *ECLIPSE-E300* has the capacity, diffusive and dispersive transport processes were neglected. This was justified as dispersion is a scale dependent process[52]. Mixing from reservoir heterogeneity was considered.

TOUGH2: EWASG (Equation of state for Water, Salt and Gas) is a partially licensed (open source within U.S.A) reservoir simulation software, capable of modelling water, salt and one non-condensable gas(NCG)[109]. Lubon and Tarkowski utilized *TOUGH2* module EWASG to model the storage of pure hydrogen within the Komorowo Formation layers within the Siliszewo anticline structure, located in NW Poland[42]. The model used by Lubon and Tarkoski makes use of real porosity values within the structure determined from previous exploration[42]. From this data, ten visible layers are determined and average permeabilities are utilized for modelling[42]. Lubon and Tarkowski determined that a maximum gas saturation of 48% would be attainable, occurring around the extraction point[42]. The percentage of water to hydrogen after extraction never dropped below 90%[42]. Unlike other simulations which utilise a Peng-Robinson EoS (the exception of [36]), Lubon and Tarkowski's model is restricted through the use of an ideal gas EoS[42]. Restrictions from the software come from only allowing the simulation of a single non-condensable gas, preventing the modelling of hydrogen storage in natural gas reservoirs or with alternative cushion gasses[109].

*DuMu^x^* is an open-source software based on the Distributes and Unified Numerics Environment (DUNE[2]) toolbox, allowing for the simulation of flow and transport processes within a porous media[33]. First implemented by Hagemann et al. for a homogeneous structure this was further developed to consider heterogeneous 3D-structures[110]. Feldmann et al. further extended the capacity of *DuMu^x^* by incorporating mechanical dispersion as a mixing process[33]. Feldman et al. pioneered modelling of hydrodynamic mixing of hydrogen within a gas reservoir. The zero-flow Neumann boundary condition initialized does however

[2] DUNE toolbox provides a foundation for the solution of partial differential equations with grid block-methods

restrict its applicability. The notable outcome from this model was that viscous fingering and gravity override have little impact within depleted gas reservoirs[33].

COMSOL Multiphysics (*COMSOL*) is a licensed software that offers an environment for defining and solving a wide array of engineering problems. Sainz-Garcia et al. made use of *COMSOL* to model various well configurations of hydrogen injection and withdrawal into the water saturated Utrillas formation within the San Pedro belt[8]. Dirichlet boundary conditions at both lateral ends set to the initial hydrostatic pressure allows for mass flow out-with the boundary, providing a more realistic description of the hydrodynamics[8]. In comparison to other studies where water mass dominated the extracted fluid, Sainz-Garcia et al. found a maximum of 6.49%[8]. Although reservoir formation affects the withdrawn fluid, it was proven that well configuration can reduce this substantially. Concomitantly, with each cycle a higher %H_2 is recovered and lower %H_2O of the withdrawn fluid. However, for the same cycle, a relationship between recovered H_2 and H_2O is observed, where higher recoverability encounters an increase in percentage mass of H_2O, exemplifying the trade-off necessary[8].

OpenGeoSys–ECLIPSE couples the open source Galerkin finite-element method *OpenGeoSys,* a software capable of processing THMC processes in porous and fractured media, with the *ECLIPSE* simulation suit, a commercially available multiphase-multicomponent flow software produced for reservoir engineering[60]. This was accomplished by Peiffer et al. where it was used to produce the first utility-scale model of THC processes hydrogen injection/withdrawal in a typical water saturated anticline structure[60]. A simplification of the biogeochemical processes was reduced to only considering methanogenesis; this is considered too simple to infer the impact of conversion[60]. It was determined that with each cycle reservoir temperature would increase, though this would be dampened through the caprocks conductive transmission[60]. Additionally, it was found that the impact of thermal change through expansion would have insignificant effects in comparison to that through hydrogen injection/withdrawal[60]. Unlike other models developed, Pfeiffer et al.'s model underwent a benchmark validation process to assure results.

4.2.1.2. Physical Testing

In addition to the numerical models constructed, physical research projects are being conducted such as "HyStorPor" which involves the testing of core samples to quantify likely chemical reactions[61]. At the large-scale "Underground Sun Storage", an Austrian project where a blend (10%H_2:90%CH_4) of green hydrogen and methane were injected within a small depleted gas reservoir has been accomplished[55]. The outcome being that the storage of hydrogen at this degree is possible, showing no migration out-with the reservoir and no negative effect on the existing storage facility[55]. Alternatively, the HyChico project intends to tap into the methanogenesis that may occur within the reservoir to produce "green methane", utilising the reservoir as a natural chemical reactor[112]. Although hydrogen storage is not the primary focus, kinetic rates and hydrogen displacement could provide valuable insight.

Table 3. Comparison of various models used in literature for porous hydrogen storage and the software packages utilised. Additional sources include [115, 116]

Authors	Ebigbo et al.	Hagemann et al.	Pfeiffer and Bauer	Feldmann et al.	Amid et al.	Pfeiffer et al.	Pfeiffer et al.	Sainz-Garcia et al.	Hemme & van Berk	Hassannayebi et al.	Lubon and Tarkoski
Year	2013	2015	2015	2016	2016	2016	2017	2017	2018	2019	2020
Model Configuration											
Biogeochemical	X				X	X			X	X	
Geo-Mechanical							X				
Hydrodynamics		X	X	X		X		X			X
Thermodynamics	X				X	X			X		
Multiphase-multicomponent	X	X	X	X		X	X	X			X
Equation of State [a]	IGL	PR	PR	PR	SRK	PR	PR	PR	n/a	n/a	IGL
Boundary Conditions	Dirichlet	Neumann & Dirichlet	Open	Neumann	n/a	Neumann & Dirichlet	Neumann	Cauchy	n/a	n/a	Neumann
Reservoir Type [b]	DGD	Aquifer	Aquifer	DGD	DGD	Aquifer	Aquifer	Aquifer	DGD	DGD	Aquifer
Model Validation						X			X		
Software Characteristics											
Software	n/a	Dumu^x	Eclipse E300	Dumu^x	Phreeqc	OpernGeoSys-Eclipse	Eclipse E300	Comsol	Phreeqc	Geochemists Workbench	TOUGH2 EWASG
Spatial Discretization [c]	FVM	FVM	FDM	FVM	FDM	FEM	FDM	FEM	FDM	FDM	FDM
Time Discretization [d]	Implicit Euler	BE	Implicit	BE	n/a	Implicit	Implicit*	Implicit	n/a	Implicit	Implicit*
Transport Processes											
Advection	X	X	X	X	X	X	X	X	X	X	X
Molecular Diffusion	X	X	X	X	X	X	X	X	X	X	X
Mechanical Dispersion			X	X	X	X	X	X	X	X	X
Availability	n/a	Open Source	Licensed	Open Source	Open Source	Open Source/Licensed	Licensed	Licensed	Open Source	Licensed	Licensed
Ref.	[113]	[110, 114]	[54, 108]	[33, 114]	[36, 118]	[60, 117]	[52, 108]	[8, 119]	[84]	[75, 120]	[42, 109]

[a] – PR – Peng-Robinson, IGL – Ideal Gas Law, SRK – Soave, Redlich and Kwong

[b] – DGD – Depleted Gas Deposit

[c] – FEM – Finite Element Method, FDM – Finite Difference Method, FVM – Finite Volume Method, * - Capable of multipoint

[d] – BE – Backwards Euler, * - Capable of IMPES (Implicit pressure and explicit saturation)

4.2.2. <u>Future Research</u>

4.2.3.Numerical Models

Ultimately, a model capable of providing full simulation of THMC processes would provide the most robust description of reservoir storage, as effects are often interrelated. However, as can be seen in Table 3. little exploration of the geo-mechanical component has been conducted.

The geo-mechanical problems within a reservoir can develop from either excessive pressure increase, cyclic loading, or stresses stemming from fluid sorption. The cyclic loading from seasonal operation can result in an increased rate of creep in turn accelerating crack growth. In combination with the excessive pressure from injection this can lead to premature failure of an otherwise safe process; little is known about these at the *in situ* characteristics of hydrogen reservoirs and hence offers a point for future works[76]. Sorption (swelling) of hydrogen in clay minerals within the reservoir, caprock and overburden can lead to irregular stress fields, potentially increasing point loads on low yield stress geology. At the same time, Heinemann et al. suggest that the dehydration of these minerals, could potentially open up swelling-induced fracture seals; with gas reservoirs being at particular risk due to only having residual water saturation at the beginning of operation[76]. Furthermore, the potential risk in structure change from fluid/rock reactions and the dynamic loading this will experience offers a point of research.

Biogeochemical research such as that produced by Ebigbo et al. Amid et al. Hemme and van Berk and Pfeiffer et al. provides a foundation for further research[36, 60, 84, 113]. The outcomes mainly affirming that, reactions are limited by available substances within the reservoir and could have significant impact on effectiveness of the storage system. Further works may include investigation into biofilm growth within a heterogeneously distributed water-saturated reservoir, and the effect this has on not only hydrogen consumption but also flow in sections of build-up. Additionally, the extension of Hassannayebi et al.'s work to consider non-isothermal conditions offers an opportunity to further understanding[75].

Hydrodynamic research topics include aspects related to the migration, mixing and dispersion of hydrogen. Hagemann et al. introduces a means to overcome the high lateral dispersion through low injection points within stratified reservoirs containing low permeability shale or mudstone layers[110]. The gravitational forces encourage vertical migration before lateral, while the low permeability layers act as resistors/barriers to the flow. Recovery is initiated as a hydrogen reaches the roof; before unfavourable lateral dispersion is observed[110]. However, this adds several complexities relating to the careful timing of the operational cycles and uncertainties that may arise from processes within the reservoir[110]. As such, this should only be pursued when the use of steeply dipping anticline structures is unavailable. Other hydrodynamic avenues for research include migration along fault lines within the reservoir and through the overburden, use of CO_2 as an alternative cushion gas and methods for enhanced recovery of native gas during cushion gas injection.

Thermodynamics affect all aspects of reservoir storage as changing thermophysical properties alter flow, mechanical properties, and biogeochemical reaction rates. Although non-isothermal flow has been accomplished at utility scale by Pfeiffer et al., the effect of this cyclic thermal loading on crack growth and hydrogen leakage is yet to be considered[60].

4.2.4. Physical Testing

Upon development of accurate model descriptions, the use of practical testing will be necessary to reaffirm conclusions drawn from models. By utilising coreflooding of reservoir rock samples, such as that employed in petroleum studies [121], aspects such as flow rate through the medium, hydrogen trapping as a result of heterogeneity, and migration along fractures can be investigated[61]. Additionally, core samples could provide answers to the effect of wettability as was done for CO_2 storage by Lv et al.[122]. Experimenting with biogeochemical consumption in a porous environment could also be tested through core samples.

In addition to this, further pilot projects like "Underground Sun Storage" are necessary to allow for an understanding of local geology within the UK. Avenues to build on this work would be through increasing the hydrogen blend (as it currently lies at 10%H_2:90%CH_4) and the extension of the injection cycle to a more realistic cycle (currently only three months). Longer shut-in periods would also allow for investigation of mineral reactions which do not typically occur in these short cycles; allowing for assessment of long-term storage potential.

5. Conclusions

It was found that currently within the UK, approximately 3.70TWh of renewable wind electricity generation was curtailed in 2020; this could further increase to 7.72TWh if the governmental goal of 40GW of installed offshore wind by 2030 is met[1, 25, 26]. By utilising this excess to produce hydrogen for storage, the intermittent nature of renewable energy that creates the curtailment can be overcome, potentially leading to the conversion and storage of 4.43TWh in 2030 – nearly two thirds of that outlined by the *Future Energy Scenarios* paper[2, 123]. Additionally, this would aid in the abatement of government spending for curtailment which if unaltered could reach £1.18bn/annum.

The UK currently only has one subsurface hydrogen storage facility with a capacity of approximately 1000 tonne (0.033TWh); meaning an additional 454 equally sized facilities would be required to deliver net-zero carbon emissions by 2050[2, 34]. A potential conversion of natural gas storage facilities may be possible; a box conversion would suggest that this would provide under one third (4.85TWh) of the necessary requirements for net-zero[39]. This could potentially be increased to 5.45TWh if an empty NTS was utilised, but this neglects daily operation and changeover periods. The notable outcome to be highlighted is that there is an urgent need for utility-scale hydrogen storage development.

Of the utility-scale hydrogen storage technologies available salt cavern storage is the most technologically mature, with four operational sites currently being implemented globally[20]. Salt caverns hold an advantage over porous storage technologies when considering the operational flexibility of the system, due to their increased number of annual cycles and higher deliverability. However, caverns are heavily constrained by their geographical availability both onshore and offshore within the UK, as well as their considerably lower capacity and increased costs[46]. This geographical constraint partnered with the capacities that will be necessary for net-zero facilitates the development of porous storage; however, the multiphase-multicomponent storage within porous reservoirs generates added complexities.

Current research for porous storage focuses on the development of simulation software to accurately model these reservoirs. To provide valid description software developed should include transport processes such as advection, molecular diffusion and mechanical dispersion as a minimum. Furthermore, software developed should consider non-isothermal, multiphase-multicomponent flow within a heterogeneous reservoir to account for; temperature variation of injected hydrogen, multiple gas component mixing and the heterogeneity of real-life reservoirs.

To further progress the development of porous hydrogen storage (be it aquifer or depleted oil/gas deposits) efforts should be directed towards constructing models capable of considering thermo-hydro-mechanical-chemical processes to allow for more robust descriptions. Additionally, small scale testing – such as that conducted by "HyStorPor" – will provide a basis for further subsurface testing as in "Underground Sun Storage"[55, 61].

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