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Subsurface carbon dioxide and hydrogen storage in a sustainable energy future

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Abstract |
Limiting climate change to less than 1.5^{o}C would require vast quantities of CO_2 storage in subsurface geological formations. Global injection rates projected by integrated assessment models synthesised in IPCC reports are on the order of ten gigatonnes per year by 2050. Industrial experience with megatonne per year storage projects allows us to evaluate the feasibility and potential limitations of a transition to the gigatonne scale. The successes with CO_2 have also led to interest in new energy technologies using subsurface fluids, including hydrogen storage underground. We review the role of subsurface CO_2 and H_2 storage in a sustainable energy transition. We have found that current deployment demonstrates the viability of CO_2 storage in a variety of geological, social, economic, and technological contexts, and is making contributions to climate change mitigation today commensurate with the impact of solar photovoltaics in the USA market. The implications of this are that CO_2 storage is well positioned to play an important role in the energy transition, and H_2 storage may benefit from this experience. However, these are not certain outcomes, with many hurdles – the development of multi-site regional scale storage, viable business models for accelerated deployment, demonstrating environmental sustainability and achieving societal acceptability – yet to be addressed.

Key points

- Subsurface carbon dioxide storage is demonstrated at industrial scales in a variety of geological, socio-economic, and technological contexts and is making significant contributions to climate change mitigation today. In that regard it is well positioned to play a significant role in a sustainable energy future, even as this role is far from certain.
- Projections of the future role of CO_2 storage suggest its existence as a permanent rather than a transitionary feature of energy systems, with fluid handling by mid-century at scales commensurate with the oil and gas industry today. While this does not appear limited by geological or engineering constraints, scaleup trajectories to mid-century are exceedingly fast when compared to historical devlopment of analogous energy infrastructure, and should be further constrained by empirical and physical models of subsurface resource use.

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- Hydrogen storage underground has emerged as a prospect for terawatt scale energy storage, a close industrial analogue is with natural gas storage. The technology is in the early development stage and immediate development is addressing uncertainties regarding the flow properties, the impacts of cycling on store integrity, and the management of microbial degradation of stored H_2.
- Both public awareness and public acceptance of carbon capture and storage is low, and the leading technical concerns are related to the subsurface. These issues have posed barriers, at times insurmountable, to project deployment with leading concerns focused on leakage and seismicity, the continued dependance on fossil fuel technologies, and lack of trust in project operators which generally comprise the oil gas industry. Underground hydrogen storage may face many of the same concerns.
- The geological understanding of CO_2 storage sites is now framed within the concept of the storage complex with multiple containment reservoirs and trapping mechanisms, and extended to complex geological settings that may include fault compartmentalised systems, and reliance on residual and dissolution trapping for injected plume immobilisation. Advances in understanding how reservoir heterogeneity controls CO_2 plume dynamics, and how subsurface fluid injection impacts reservoir mechanics open the possibility of predictive modelling of CO_2 flow and pro active management of seismicity to ensure their management within envelopes of safe project operation.
- A number of viable business models have been demonstrated for CO_2 storage, although revenues from enhanced oil recovery underpin commercial viability for most current projects, and due to technological synergies it is plausible that this will continue as CO_2 storage scales up to gigatonne scales. This poses significant challenges that remain little studied, including technical issues in the quantification of the climate benefit, socio-political barriers to public acceptance and ensuring a just transition, and policy and economic challenges in incentivising the development CO_2 storage in the absence of co-current oil production.

1. Introduction

Carbon capture and storage (CCS) comprises the capture of CO_2 from anthropogenic emissions sources or the atmosphere and the permanent sequestration of the CO_2 in the deep subsurface. In existing projects, the carbon dioxide is captured from industrial processes and power production, transported by pipeline, and stored by injection underground into geological formations, either oil and gas fields or porous sedimentary rocks filled with brine known as saline aquifers (Figure 1).

There is a vast deployment of CO_2 storage in model projections of futures in which climate change is limited to 1.5 ^{o}C or less than 2^{o}C. The global injection rate in scenarios compiled by the United Nations Intergovernmental Panel on Climate Change are between 3 and 10 gigatonnes CO_2 per year by 2050 (IPCC, 2014, 2018, 2022). This deployment is a similar scale to the presenty-day hydrocarbon industry and implies a scaleup of subsurface CO_2 storage over the next 30 years at rates of growth rarely achieved in the history of energy technology (Zahasky & Krevor, 2020). In contrast to the widespread view of CCS as a transitionary technology, these scenarios show CO_2 storage as a central feature of a sustainable energy future, mitigating emissions from difficult to decarbonise industry and in the generation of negative emissions.

There are increasing examples of technical and commercial success in the execution of megatonne per year CO_2 storage projects (Figure 1). In 1996 the Sleipner Project began injecting CO_2 at rates close to 1Mt yr^{-1} into the Utsira Sandstone beneath the Norwegian North Sea. By 2020 there were 26 commercial CCS projects injecting into saline aquifers and mature oil fields storing around 30 Mt CO_2 annually. While considered a nascent technolgy, this rate of CO_2 mitigation is significant, and can be compared with the ~60 Mt of CO_2 equivalent emissions avoided from solar photovoltaic in the USA in the same year (IRENA, 2019). On the other hand, far more projects were ultimately halted due to a range of social, economic, legal, political, engineering, and geophysical barriers (Abdulla et al., 2020). There remain significant uncertainties around the feasibility of achieving gigatonne-scales.

Underground carbon storage has achieved a stage where it is demonstrated in a variety of settings and is providing a significant climate change mitigation benefit today (Ringrose, 2020; Zhang et al., 2022). At the same time, its role in a sustainable energy future is far from established. We can thus evaluate future projections of vast and rapid deployment with the knowledge acrrued from decades of research and project development, successes, and failures. The successes of CO_2 storage are also giving rise to further interest in the use of subsurface fluids, including underground carbon mineralisation (previously reviewed in Snæbjörnsdóttir et al., 2020), and as energy carriers for dispatchable consumption. We include a brief review of underground hydrogen storage, making use of lessons from CO_2 storage to identify potential and key issues to address in the coming years.

This Review assesses the feasibility of the projected roles of CO_2 and H_2 storage in the sustainable energy transition. We find that existing projects demonstrate deployment in a diverse range of geological, technological, social, regulatory, and economic contexts. Viable business models exist in localities, like the USA and Norway, with concentrated sources of anthropogenic CO_2, the necessary legal framework, and where cost recovery can take place of around \$30tCO_2^{-1}. The past 25 years of deployment are yielding significant climate change benefits. Analogous subsurface fluid technologies like hydrogen storage underground may see the benefit from the knowledge accrrued from both CO_2 and natural gas storage. In the near-term, CO_2 storage would gain from the resolution of uncertainties over the quantification of the climate benefit when combined with enhanced oil recovery, the inclusion of constraints in integrated assesment models on scaleup rates, and the factors underpinning current low public acceptability and awareness of the technology. Over the coming decade it will be important to develop approaches to more accurate forecast modelling and verification of CO_2 plume migration and trapping, the proactive management of seismicity, multi-site regional storage resource management, and the verification or mitigation of CO_2 leakage from very large stores, guaranteeing rates of less than 0.01% of the injected volume annually. Addressing these issues would enable for CO_2 storage to evolve from a technology demonstrated at industrial scales today to the envisioned global scale business rivalling the current oil and gas industry.

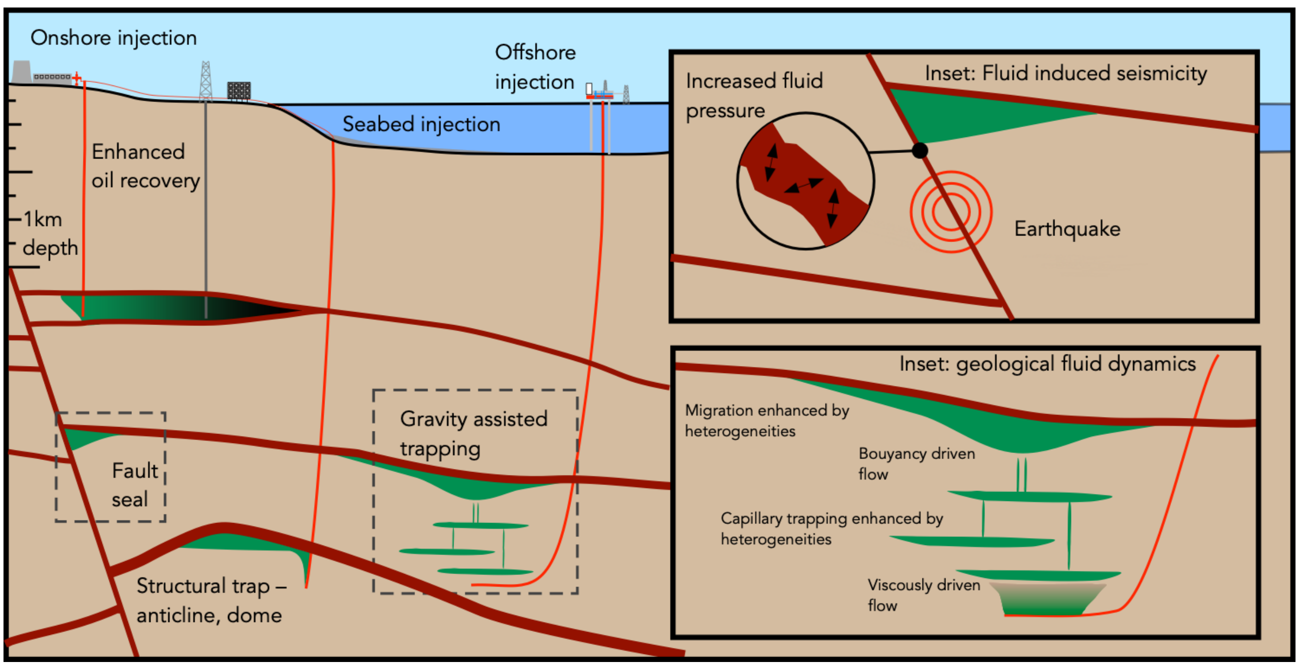

Figure 1. Geological storage complexes in use by industry scale projects today. The insets show features of the reactive fluid dynamics discussed in §2.2 and the injection induced seismicity discussed in §2.3

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2. Geological opportunities and limitations of carbon storage underground

Topics in Earth Science are central to the definition, possibilities, and limitations of carbon storage. Subsurface geology underpins the geography of storage, defines how much CO_2 can be injected and how quickly, controls trapping, and determines the risks of CO_2 escape and seismicity.

2.1 The Geological Storage Complex

The geological storage complex is made up of the subsurface strata into which the CO_2 is injected and which ensure its containment. The complex comprises a porous and permeable reservoir targeted for storing the CO_2, an impermeable overlying caprock preventing upward migration, and a combination of geological structures and characteristics of the rocks that combine to ensure that the CO_2 is trapped underground permanently (Figure 1). This combination of features occur in sedimentary rock systems. The geography of sedimentary basins places the upper most bound on the global distribution of storage resources (Benson & Cole, 2008).

The lithologies of the reservoirs where CO_2 is stored are either siliclastic, e.g., sandstone, or carbonate rocks. Reservoirs for existing projects have average permeability of 10^{-15} m^2 or greater, and porosity ranging 0.07 – 0.22 (Krevor et al., 2019). They must be deep enough such that the injected CO_2 is in a liquid or supercritical state, typically below 800-1000m in the subsurface. Two dominant reservoir types have been used over the past 25 years as industrial scale storage resources: brine-filled porous rock formations known as saline aquifers, and depleted or depleting hydrocarbon fields (Orr, 2018). Saline formations offer the greatest storage capacity yet have the least characterised properties, particularly in regions that are not hydrocarbon provinces. Hydrocarbon reservoirs offer the opportunity for revenue from enhanced oil recovery, proven sealing caprocks, data, and infrastructure. These can combine to result in significant cost and risk reduction (Alcalde et al, 2019; Gross, 2015). However, complications can arise from the risk of leakage through legacy wells in an oil field, differences in fluid properties between CO_2 and hydrocarbons, production history, and upgrades required for using infrastructure with CO_2 (Loizzo et al., 2010; Hannis et al, 2017; Raza et al., 2018).

Following from the geological requirements of a suitable store, identification of suitable sites must focus on assessing containment, the capacity, and injectivity (Lloyd et al., 2021; Ringrose et al., 2021). Sealing caprocks for oil and gas have been dominated by two categories of sedimentary process – shales formed during marine transgression, and evaporite deposits, originating either from sabkhas or evaporitic interior basins (Allen & Allen, 2013). However, there are many exceptions and fine grained clastics and carbonates can serve as sealing layers. The key is that there are low permeability rock units that are both pervasive and ductile, such that their sealing qualities can endure throughout tectonic events over geological timescales. Workflows to quantify long-term fault seal performance for CO_2 are being developed (Miocic et al., 2019; Wu et al., 2021; Bentley and Ringrose et al., 2021). In addition to the seal itself, the overlying rock layers, known collectively as the overburden, are now considered as important for ensuring containment security. These can include secondary or tertiary reservoirs and pressure seals (Hannis et al., 2017; Roberts et al., 2017).

Site identification criteria have broadened with experience to include migration-assisted trapping as well as closed or semi-closed traps. The storage sites for the Northern Lights and Quest Projects have no defined trap structure such as the arch-like anticline, or a dome (Equinor, 2020; Shell Canada Energy, 2021). The Tubaen formation at Snøhvit is bound, or compartmentalised, by faults (Grude et al., 2014). The Gorgon project makes use of water production wells for pressure management (Chevron, 2022). To date, CCS deployment has been restricted locations known as extensional basins where tectonic plates are stretching, as these are characterised by low background seismicity. However, widespread storage will require a wider range of settings including locations that are not hydrocarbon bearing and where geological data is sparse (Sun et al., 2020, 2021).

2.2 Reactive fluid dynamics, plume migration and trapping

The predictability of a CO_2 plume injected into the subsurface is important for permitting, and site assurance through monitoring and verification of stored CO_2. The migration is driven by the pressure gradients between the target reservoir and surrounding formations, pressure gradients induced by injection, and buoyancy forces associated with the density difference between CO_2 and ambient brine (Huppert et al. 2014; Szulczewski et al. 2012). This presents both a challenge and an opportunity. Flows in the near well-bore environment may be influenced by injection strategies. Once CO_2 moves further, the path of migration is controlled by features of the rock and fluids – buoyancy, reservoir heterogeneity, and the geometry of the stratigraphic trap.

Important examples of exhaustively characterised CO_2 migration are the Sleipner and In Salah projects, with injection rates of roughly 1Mt yr^{-1} (Bickle et al. 2007; Verdon et al. 2013). At the Sleipner project offshore Norway, the reservoir is very permeable, and migration is dominated by buoyancy-driven spreading. This is particularly clear at the top of the reservoir where the topography of the bounding cap rock, the Nordland Shale unit, dictates the evolving pattern of flow (Cowton et al. 2018). Carbon dioxide temperature and fluid composition also play a role in plume footprint and matching to observed data at Sleipner (Hodneland et al., 2019). This is in contrast to the In Salah project where the project was halted due to excessive reservoir pressurisation. Here the reservoir was a thin (20m thick) and low permeability fractured sandstone. In this scenario, injection pressures controlled plume migration.

The chief uncertainty in predictions for plume migration is the heterogeneity of subsurface reservoirs (Figure 1). It remains a significant challenge to characterise reservoir scale heterogeneities at scales below the resolution of seismic imaging, typically a quarter of the seismic wavelength. Centimeter-to-metre scale capillary and permeability heterogeneities may have a significant impact on the larger scale flow and trapping (Benham et al. 2021; Boon & Benson, 2021; Jackson & Krevor, 2020). Because they are difficult to characterise, they are a major source of uncertainty.

The immobilisation and trapping of CO_2 plumes is important for the long-term security of stored CO_2. For many scenarios, trapping of the CO_2 primarily occurs due to a structural trap. Subsequent plume immobilisation may be driven by the capillary trapping of residual CO_2 and through dissolution of CO_2 in water. Residual trapping occurs simultaneous with plume migration. The residual trapping of CO_2 may be greatly enhanced by heterogeneities which act to disperse the plume, and provide barriers to buoyancy-driven flow (Hesse & Woods 2010; Krevor et al 2011). At the largest scales residual trapping can immobilise plume migration (Hesse et al. 2008), a process which has been observed with modest injection volumes at the Otway test site in Australia (Popik et al. 2020).

Dissolution trapping may require decades or longer depending on the extent of fluid convection in the reservoir (Nordbotten and Celia, 2012). The dissolution of CO_2 into water produces dense CO_2-saturated waters (Riaz et al. 2006). This may lead to convection in highly permeable reservoirs (Neufeld et al. 2010), and enhanced dissolution rates in highly heterogeneous formations (Gilmore et al. 2020). As with residual trapping, the dissolution of CO_2 can act to halt the advance of the CO_2 plume (Gasda et al. 2011; MacMinn, Juanes 2013). Significant dissolution rates have been inferred at field scale for magmatically derived CO_2 (Sathaye et al. 2014). Mineralisation of the CO_2 may also serve as a trap. However, in sedimentary systems there may be an insufficient supply of reactive minerals, and rates of chemical reactions are often sluggish, requiring millenia, and generally much longer timescales than in igneous rocks (Snæbjörnsdóttir et al., 2020; Krevor et al., 2019).

These trapping mechanisms act to immobilise the CO_2 plume, and hence minimise any risks of leakage through pre-existing wells or fault systems (Nordbotten 2009; Gilmore et al. 2021). It is plausible that enhanced trapping rates will mitigate leakage rates in many scenarios (Jones et al., 2015; Alcalde et al., 2018).

2.3 Managing induced seismicity

The potential for subsurface CO_2 injection to cause earthquakes, and approaches for managing and derisking this outcome, has been an area of increasing interest for subsurface CO_2 storage. Earthquakes occur when faults rupture, leading to runaway slip and the radiation of elastic waves (Scholtz, 1998). The fundamental mechanism to induce fault slip—and, potentially, earthquakes— is a combination of two types of stress changes: an increase in shear stress on the fault, and a reduction in compressive normal effective stress clamping the fault. The former can occur in bounding faults as a result of fluid withdrawal, as was the case in the Groningen gas field (Candela et al., 2019). The latter occurs as a result of fluid injection leading to an increase in pore fluid pressure. Coupling between pressure diffusion and rock deformation results in changes in stress, known as poroelastic effects (Figure 1, inset) (van der Baan, 2021). Poroelastic effects are often secondary, and they can play a role in triggering distant earthquakes (Zhai et al., 2019). Cumulative injected volume will impact the total pressure increase, which will affect the slip tendency on reservoir faults, especially in reservoirs that are compartmentalized or have low permeability (McGarr, 2014; Watkins et al., 2022). A growing number of field observations suggests that fluid injection rates are also a determinant for induced earthquakes (Weingarten et al., 2015; Tang et al., 2018). This effect has its underpinning in the frictional behavior of faults under varying normal stress and can be explained from the onset of frictional instabilities (Olsson, 1988; Linker and Dieterich, 1992; Alghannam and Juanes, 2020).

While most earthquakes—and certainly the most damaging earthquakes—are of tectonic origin, earthquakes can be triggered by human activities (National Research Council, 2013; Ellsworth, 2013; Grigoli et al., 2017). These include fluid injection processes analogous to CO_2 storage including subsurface disposal of wastewater (Healy et al., 1968; Raleigh et al., 1976), conventional oil and gas production (Segall, 1989), gas injection (Gan and Frohlich, 2013; Cesca et al., 2014), geothermal energy extraction (Brodsky and Lajoie, 2013) and groundwater pumping from shallow aquifers (Amos et al., 2014).

Because of the similarities with large-scale geologic wastewater disposal, concerns about seismicity hazard have been raised in the context of geologic CO_2 storage (Zoback and Gorelick, 2012; Verdon et al., 2013; Jha and Juanes, 2014; White and Foxall, 2016). The dramatic increase in seismicity in the mid-continent of the United States starting in 2009 is a cautionary tale on the potential effects of large-scale subsurface fluid injection (Ellsworth, 2013; Keranen et al., 2014). This increasing trend, however, has reversed in recent years as a result of imposing limits on per-well injection rates and injecting into more permeable geologic strata and away from faults (USGS, 2019). The most immediate lesson learned is that site selection is key.

While certain geologic settings, such as those dominated by granitic rocks, would be prone to induced earthquakes and leakage risk that could compromise a CCS project (Chen et al., 2000; Zoback and Gorelick, 2012), in the short term induced seismicity should not pose a barrier to CCS deployment. Many formations exhibit excellent promise for storing very large quantities of CO_2, especially in normally-consolidated, shallow (< ~3km) siliciclastic sequences (those characterized by alternating sand-dominated and clay-dominated sediments) where ductile rocks can accommodate substantial deformation and faults behave aseismically (Ikari et al., 2009; Bürgmann, 2018). Indeed, large volumes of buoyant fluids have remained stable in geologic traps over millennia in regions experiencing strong and frequent earthquakes, like Southern California, even under substantial overpressures (Juanes et al., 2012). These environments include offshore sedimentary formations, which can have high injectivity and storage capacity, and in many areas, like India, provide the only viable geologic storage reservoirs (Ringrose and Meckel, 2019).

A priori prediction of induced seismicity is challenging for a number of reasons. The state of stress on a fault and the fault strength are heterogeneous and uncertain. The evolution of stresses on faults is coupled with fluid pressures and therefore depends on reservoir architecture and hydraulic properties like porosity and permeability, which are also heterogeneous and uncertain. However, the frictional behavior—seismic vs aseismic slip—depends on the lithology, and this offers an opportunity to select storage sites where faults slip aseismically, minimizing the risk of induced seismicity.

In the absence of sufficient information to determine and mitigate the processes that trigger earthquakes, authorities have set up regulatory monitoring-based frameworks known as “traffic-light systems” with varying degrees of success (Baisch et al., 2019). These are intended to reduce the chance of induced earthquakes by specifying circumstances when injection should be halted or reduced. These frameworks are empirical and reactive.

There is broad consensus that more sophisticated approaches are needed (Lee et al., 2019). Ideally, such methodologies should be built on comprehensive information about the subsurface to calibrate geomechanical and earthquake source physics models. These physics-constrained models should then be validated by comparing their predictions with subsequent observations made *after* calibration, allowing for forecasting and proactive management of reservoir operations to mitigate triggered seismicity (Hager et al., 2021). Potentially, such approaches would also permit judicious placement of new injection wells and implementation of remedial measures (such as balancing injection or fluid withdrawal). We anticipate that this type of model-based management and mitigation could play an important role during the scale-up of CO_2 and H_2 geologic storage.

3. Underground hydrogen storage: lessons learned from underground CO_2 storage

The commercial demonstration of CO_2 storage has increased confidence in the use of subsurface fluids in energy applications. Underground hydrogen storage (UHS) is one such technology envisioned to play a role in seasonal-based energy storage at the grid scale (Kabuth et al., 2016; Heinemann et al., 2021b). In this role, the storage will be cyclic, with H_2 gas temporarily stored to be later extracted to meet demand. This differs with CO_2 storage with its focus on permanent sequestration, and is more similar to the use of underground natural gas storage (UGS) today (Figure 2). The potential for subsurface H_2 storage reaches terawatt hours of energy content globally, far exceeding foreseeable demand (Heinemann et al., 2021a). However, the knowledge base and industrial experience is just beginning. We summarize some similarities where experience from CO_2 storage can be exploited to accelerate UHS technology development.

The geological host for hydrogen storage must meet some of the requirements for CO_2 storage: away from sensitive faults, sufficient capacity, good injectivity, and a secure trap. However, there are many important distinct features. Carbon storage is for permanent sequestration, and open ended complexes relying on residual and dissolution trapping can be used. Hydrogen is a commodity where its purity loss should be minimized during storage and extraction, implying that structural traps a requirement (Amid et al., 2016). The hydrogen rich fluid has lower compressibility than CO_2. The lack of sharp fluid density increase with depth opens up shallower options for hydrogen. The seasonal cycling of UHS may place greater emphasis on the co-location of sites with hydrogen production to minimize cost and transport risk, and streamline storage operations (Simón et al., 2015). Since H_2 has low volumetric energy density and carries a high risk of steel pipeline embrittlement, it is poorly suited for long-distance pipeline transport or shipping (Hafsi et al. 2018). This implies that proximity will need to be weighted more heavily than for CCS in site selection criteria.

Salt caverns have been used for decades for natural gas storage appear especially well suited for hydrogen storage. Example projects in the UK and USA have operated for many decades (Tarkowski et al., 2021). However the capacity of salt caverns is limited by the lower volumetric energy density of H_2 gas compared to CH_4. The availability of sufficiently thick salt deposits is geologically restrictive (Heinemann et al., 2021b; Caglayan et al., 2020). Expanding available capacity through engineered salt caverns has high capital costs (Tarkowski, 2019). Saline aquifers and depleted oil and gas reservoirs are ubiquitous, considered low risk, and were recently identified as the most cost-effective H_2 subsurface storage option (Tarkowski, 2019; Hashemi et al., 2021; Heinemann et al., 2021a).

Hydrogen storage will cause a variety of physically and chemically complex effects that are currently not well constrained. Understanding flow, containment and hysteresis of H_2 in rocks is not as advanced as CO_2 and presents a critical knowledge gap for H_2 storage (Hashemi et al., 2021; Heinemann et al., 2021a,b). Injectivity loss due to salt precipitation is a well-studied phenomenon for CO_2 storage (Miri and Hellevang, 2016), while for UHS there is still uncertainty around analogous evaporative processes. The intermittency of injection and withdrawal cycles on shorter time-frames, compared to monotone storage of CO_2, raises additional challenges for wellbore integrity and rock plastic deformation under cyclic loading (Carroll et al., 2016; Kumar et al., 2021). In addition, fault integrity could be a greater risk with increased cycling frequency and loads, as observed in petroleum applications (Kaldi et al., 2013). The challenges of microbial conversion could limit underground storage to deep, high salinity formations to suppress microbial activity (Dopffel et al., 2021; Thaysen et al., 2021). Increased understanding of microbial conversion is needed to unlock the potential for re-use of depleted hydrocarbon fields and aquifers.

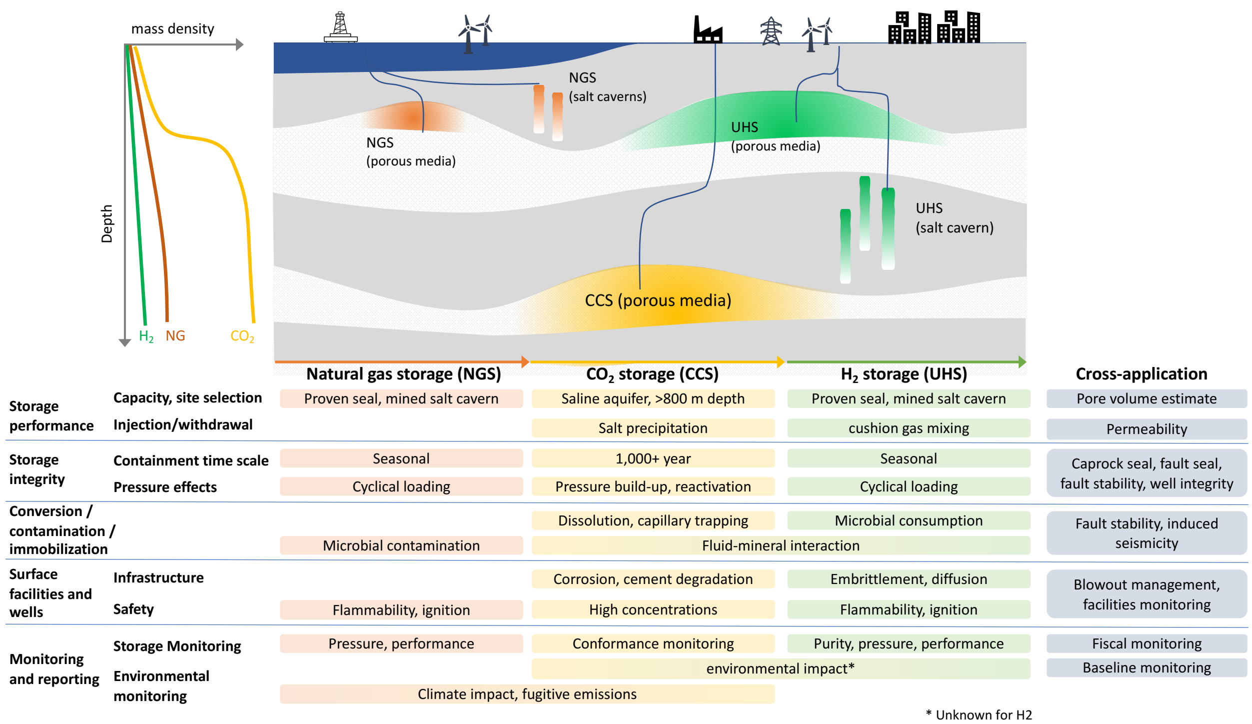

Figure 2. Cross comparison of subsurface storage of natural gas, CO_2, and H_2
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4. The contribution of CO_2 storage to sustainable development

Sustainable development has been a part of the discussion around carbon capture and storage from its inception (IPCC, 2005). It has been used by the IPCC as an organising framework for evaluating approaches to mitigating climate change (IPCC, 2014, 2018, 2022). Definitions emphasise the need for development in ways that do not compromise opportunities for others (See Principle 3 of the 1992 Rio Declaration, United Nations, 1992). Recent IPCC reports have linked technologies, including CCS, with their contribution to and detraction from the Sustainable Development Goals (SDGs) and these are shown in Figure 3 (IPCC, 2018; Mikunda et al., 2021). The contributions of technologies to sustainable development are evaluated through consideration of their impacts on environmental, economic, and social issues.

Carbon capture and storage is frequently discussed as a transitionary technology towards a sustainable energy system (Herzog and Drake 1996). The technological maturity of CCS components suggested potential for cost-effective, large-scale emissions reductions from coal-fired power production on a shorter time frame than alternatives, and as a potential stepping stone to a hydrogen energy system (IPCC, 2005; Hetland and Anantharaman 2009; Audus et al. 1996; Mathieu 2002). In contrast to this transitionary framing, modelled development pathways synthesized by the IPCC suggests a long-term role for CO_2 storage in energy systems associated with power production, industrial processes, and negative emissions chains (IPCC 2014, 2018, 2022). In these scenarios, CCS scales up to mid-century and is then sustained or increased to 2100. Within these narratives CCS contributes to sustainable development through its contributions towards climate change mitigation (environment) and the provision of a cost-effective low-carbon energy source (economic). More recently, the potential for CCS to facilitate employment opportunities in industrial regions has also been identified as a contribution towards just transition (social) (Swennenhuis et al., 2022).

Figure 3. United Nations Sustainable Development Goals with potential contributions and detractions from subsurface CO_2 storage identified in *IPCC, 2018*.

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4.1 Environmental sustainability

Environmental sustainability is the purpose of subsurface CO_2 storage as a climate change mitigation technology. Lifecycle analysis has been extensively applied to a variety of CCS chains and ongoing operations demonstrating its efficacy and potential. These analyses underpin their representation in energy systems models, and the resulting projections of gigatonne scale deployment featured in the IPCC reports. The leading environmental impacts are associated with surface operations including the energy and chemical consumption of the CO_2 capture processes and energy for the compression for transport. Energy consumption from subsurface operations, including field development, injection and monitoring, comprise 1% or less of the lifecycle costs (Volkart et al., 2013; Pehnt & Henkel, 2009). However, two areas in which life cycle emissions are sensitive to aspects of the subsurface are in the potential CO_2 escape, or leakage, from the subsurface store, and the use of CO_2 to produce oil in enhanced oil recovery processes.

The permanence of stored CO_2 is central to its effectiviness in emissions mitigation. There are no examples of CO_2 leaking to the atmosphere from existing industrial CO_2 storage sites. However, the issue receives major focus in project development where well integrity is the considered the leading risk of injected CO_2 escape (Alcalde et al., 2018; Pawar et al., 2016). This follows from experience in the hydrocarbon industry where gas esccape from the subsurface through leaky wells is pervasive (Kang et al., 2016; Davies, 2014). Risk analysis in FEED studies of industry projects consider that over 30% of abandoned wells have potential to serve as leakage pathways (Shell UK Limited, 2016).

The leading environmental concern of CO_2 leakage is the impact on climate change, although there may be impacts on drinking water quality and offshore ecosystem health (Jones et al., 2015). Because of the very large amounts of CO_2 storage envisioned in climate mitigation scenarios, e.g., 1000 Gt CO_2 stored by 2100, models show that annual leakage rates of greater than 0.01% of stored CO_2 will negate the climate mitigation benefit of having stored the CO_2 (Shaffer, 2010; Hepple & Benson, 2005; Haugan & Joos, 2004). Regulations generally require the remediation of leaking wells, and there is significant industrial experience in carrying this out (See EPA, 2018). At the same time, there is a gap in identifying worfklows for verifying storage integrity to the level of precision, e.g., <0.01% annually, required.

Most CO_2 storage today takes place in oil fields where it is used to boost oil production, a process known as enhanced oil recovery. The revenues are so significant that economic models show that enhanced oil recovery could be the dominant CO_2 storage configuration as CCS scales up to gigatonnes per year (International Energy Agency, 2015; Kolster et al., 2017; Edwards and Celia, 2018; Hepburn et al., 2019). Life cycle analysis of existing operations and envisioned scenarios with incentives for maximising CO_2 use shows that for every one ton of CO_2 stored underground 1.5-3 tons of CO_2 are emitted to the atmosphere, primarily from combustion of the end products of the produced oil (Jaramillo et al., 2009; Cooney et al., 2015; Sminchak et al., 2020; Stewart & Haszeldine, 2015; Núñez-López & Moskal, 2019). The net climate benefit hinges on the extent to which the oil will add, or is additional to, total oil production in a market. If it is additional the emissions from combustion negate the benefit of the CO_2 storage. If instead the produced oil displaces production from other parts of the market, there will be no net increase in greenhouse gas from the oil. This topic has seen little analysis. In an economic modelling study the IEA found that as little as 20% of the oil in a global market could be additional, largely preserving the climate benefit of CO_2 storage when combined with enhanced oil recovery (International Energy Agency, 2015). However, there are questions around how the climate benefit can be monitored at the market scale, and whether this will be supported by the public.

4.2 Societal acceptability

The widespread use of CO_2 storage will require broad societal engagement. Case studies demonstrate that social impact assessment, community engagement, and participation must be considered from project outset and tailored to local context (Mabon et al., 2017; Ashworth et al., 2015; Alcalde et al., 2019; Haug & Stigson; Akerboom et al., 2021). Indeed, as with other energy technologies, insufficient community support has contributed to the failure of attemps to implement CCS (Brunsting et al., 2011; van Egmond & Hekkert, 2015). Further, openness of technology, transparency of information and citizen participation are necessary to achieve broad acceptance for CCS (Glanz et al., 2021). Public attitudes towards CCS have been evaluated throughout Europe, in Canada, the United States, Brazil, Japan, China, Indonesia, and Australia (Buck, 2021; Broecks et al., 2021; Tcetkov et al., 2019 ; Selma et al., 2014; Whitmarsh et al., 2019; Chen et al., 2015).

The leading predictor for the acceptance of CO_2 storage is how the public perceives the benefits of the CCS technology chain relative to the risks (Selma et al., 2014; Tcvetkov et al., 2019). Publics perceive the leading benefits of CCS to be its contribution to climate change mitigation. Job creation and investment in a community are also frequently cited in surveys. The leading risks perceived for CCS are associated with the subsurface (Whitmarsh et al., 2019; Gough & Mander, 2019; Selma et al., 2014). Publics cite risks of CO_2 leaking to the atmosphere and associated industrial catastrophes, and the potential for induced earthquakes. People are also concerned about the long term fate of CO_2 and storage site management challenges (Vercelli et al., 2017). The gap between public perception of leakage risk compared with experts who consider the risks small suggests an opportunity for communication to improve public acceptance (Broecks et al., 2021).

Concerns around sustainability are also frequently captured. Issues raised include the character of CCS as an end-of-pipe solution, its association with the continued use of fossil fuels, and its potential to divert financial and other resources from renewable energy development (de Coninck, 2008; Selma et al., 2014). There is a perception that CCS does not address the root cause of CO_2 emissions, and upholds the status quo of non-sustainable production (Vergragt et al., 2011; Cox et al., 2020). There is also a lack of trust in industry and in the sincerity of efforts by corporations to transition towards a more sustainable future (Gough et al., 2017, 2018). There may be an opportunity to change this outlook with new narratives that position CCS as a component of carbon dioxide removal chains, addressing concerns about CCS as an end-of-pipe solution only (Gough and Mander, 2019; Janipour et al. 2021).

Studying public perception is challenging for emerging technologies (Ashworth et al, 2015). A prevailing feature of societal research in CCS is that there are low levels of public awareness (Whitmarsh et al., 2019; Pianta et al., 2021; UK Department for Business, Energy & Industrial Strategy, 2021a; Ostfeld & Reiner, 2020). Perception also varies with geography with increasingly negative opinions the closer a storage site is located, and whether or not the source of the CO_2 is domestic or imported (Haug & Stigson, 2016; Akerboom et al., 2021; Merk et al., 2022). There is evidence that benefit perception varies depending on the particular CCS chain (Dütschke et al., 2016; Gonzalez et al., 2021; Glanz et al., 2021).

Public perception of CCS will evolve further with deployment. Concerns might decrease with increasing experience or might increase according to how projects are perceived in terms of procedural and distributive fairness, and tangible economic and wider benefits (Hansson et al., 2022; Dowd et al. 2015). Social science research emphasises the importance of understanding the local community context within which CCS developments sit. Project-specific measures to increase societal acceptance may include early and open engagement of stakeholders, provision of information and sources to support familiarity with CCS, and understading of community context and possible societal impacts, as well as tools such as community compensation. In short, societal acceptability of CCS will be place and application specific, and depends on when, where, at what scale, how it might be implemented, and trust in local industry and decision-makers (Whitmarsh et al, 2019; Gough & Mander, 2019).

4.3 Regulatory frameworks

There are mature and detailed legal frameworks enabling CO_2 storage at the international, national, and sub-state level in Europe, the United States, Canada, and Australia (Table 1). These address issues from permitting and environmental assessments, to public consultation, tax credits, and long term liability (Ghaleigh, 2016; Havercroft, 2018). These instruments set out requirements for site permitting including exploration, and development; clarify ownership issues with respect to existing regulations around pore space and subsurface mineral rights; define requirements for succesful operation and monitoring; and specify requirements for post-injection site stewardship and eventual closure. There are broad similarities among the enacted frameworks with some significant variations in how pore space ownership is designated and the length of time required for stewardship of the site post-injection, from 15 years in Australia to 50 years in the USA.

We use the EU's CCS Directive as illustrative. The Directive has the objective of permanent storage, prohibits ocean storage, requires the permitting for exploration and storage, emphasises careful site selection, risk assessment and monitoring, and links with the EU's trading scheme. Monitoring injected CO_2 is linked to that required by the Emissions Trading Scheme (ETS) such that liability for climate damage as a result of leakages requires surrender of emissions trading allowances for any leaked emissions – a rigorous level of monitoring. Furthermore, operators are required to provide financial security (i.e. to provide for 30 years of monitoring). However, after closure of the storage site, liability transfers from the operator to the state (or 'competent authority' in the language of the Directive) after no less than 20 years. This transfer of responsibility takes place after a process of 'history matching' whereby the monitored CO_2 is demonstrated to have behaved in a manner consistent with the operator's ex ante modelling, there is no detectable leakage, and the CO_2 is moving towards long-term stabilization (CCS Directive, Recital 30, Articles 18-19).

Jurisdiction; treaty body	**International legal instruments**
International; International Maritime Organisation	London Protocol
NE Atlantic; European Union & 15 countries	OSPAR
European Economic Area & UK	European CCS Directive (Directive 2009/31/EC)

Country and states	Country and state specific regulations	Policy market support
European Economic Area & UK	EU CCS Directive transposed to domestic law	EU Emissions Trading Scheme Norwegian Carbon Tax
USA	US Safe Drinking Water Act Underground Injection Control Program	45Q tax credit
North Dakota	ND Century Code Ch. 38-22 & ND Administrative Code 43-05	
Wyoming	WY Stat §35-11-313 (2019)	
Other	Several states have enacted laws and obtained legal primacy over the USDWA for enhanced oil recovery and extended those laws to regulate CO_2 storage with enhanced oil recovery	California Low Carbon Fuel Standard
Canada	Primary authority with individual provinces	
Alberta	Carbon Capture and Storage Statutes Amendments Act 2010 Technology Innovation and Emissions Reduction Regulation (TIER)	 TIER fund price
Australia	Offshore Petroleum and Greenhouse Gas Storage Act (2006); National Greenhouse and Energy Reporting Act (2007)	
Victoria	Greenhouse Gas Geological Sequestration Act 2008; Offshore Petroleum and Greenhouse Gas Storage Act 2010	
Queensland	Greenhouse Gas Storage Act 2009	
Western Australia	Barrow Island Act 2003	
South Australia	Petroleum and Geothermal Energy Act 2000	

Table 1. Indicative international, national, and sub-state laws governing the underground storage of CO_2 and policies supporting market based development of projects. For additional policies directed at specific projects, e.g., government grants, see compilations at Rassool et al., 2020 and IEA 2022.

5. Technical feasibility of scaling up

The technology required for subsurface CO_2 storage at the single field scale is mature, including resource classification, appraisal, site development, operation, and CO_2 plume monitoring. At the same time, these technologies are evolving as experience is gained, and with an eye towards scaleup driven by expectations about the increasing role of subsurface storage in climate change mitigation plans.

5.1 Storage resource assessment

Estimates of the storage resource base have been a focus from the initial development of subsurface CO_2 storage. Resource assessments have been performed by government and research organisations for approximately 20 countries. Compilations of this data suggest that 10,000 – 30,000 Gt may be stored in suitable subsurface geology around the world (Figure 4)(Benson et al., 2012; Baines et al., 2022).

Recently, the United Nations Economic Commision for Europe and the Society of Petroleum Engineers Storage Resources Management System (SPE SRMS) asset classification systems have been developed for storage resources (UNECE, 2016; Society of Petroleum Engineers, 2017). A hierarchy of categories, e.g., from Resources to Capacity, is driven by the state of commercial feasibility (Figure 4). These systems emphasise near term commerciality, and the highest level of classification is only achieved with imminent or ongoing project investment and operation. An evaluation of global storage resources found that approximately 96% would classify as “Undiscovered Resource” in the SRMS, and a further 4% as “sub-commercial” resource. Much less than 1% of the resource has been developed to the commercial status which is termed “capacity”.

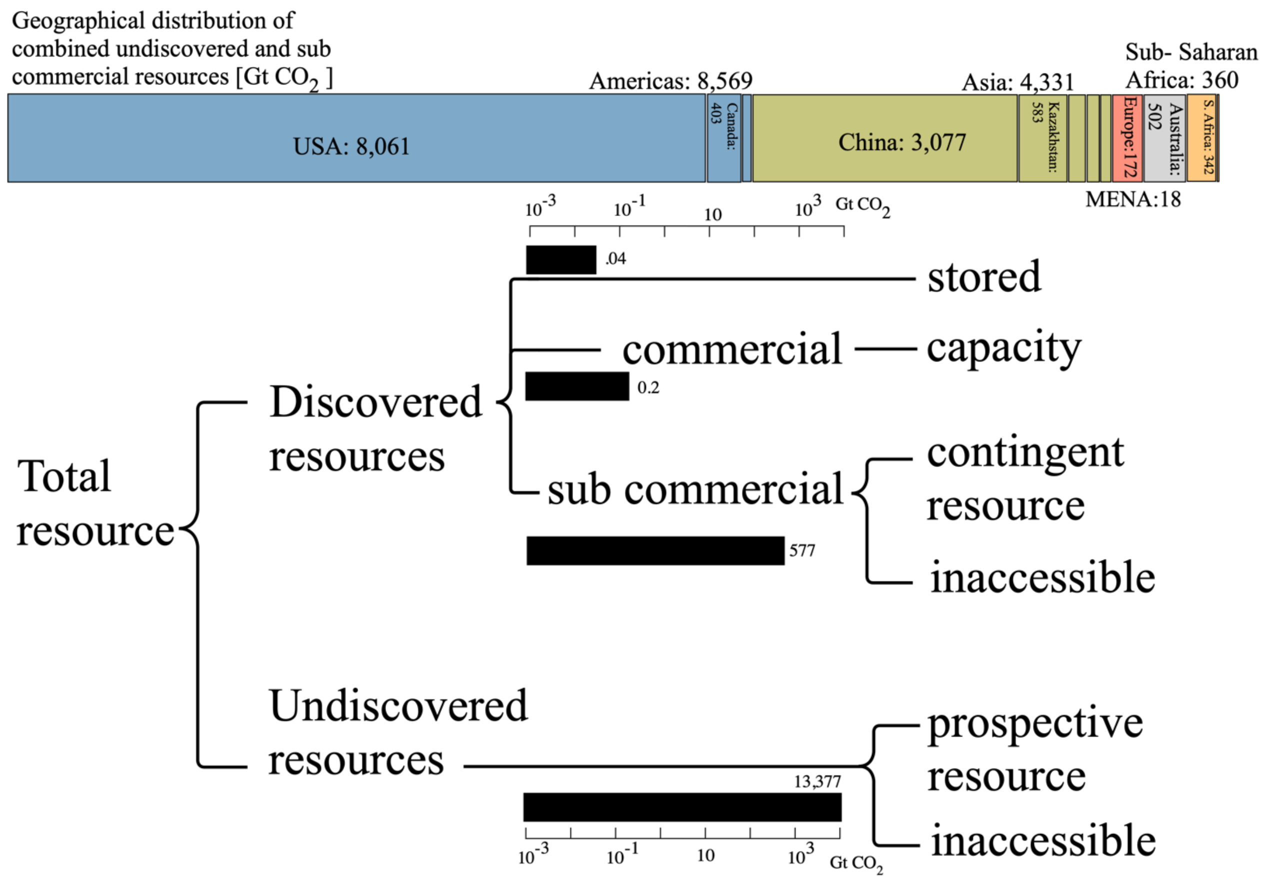

Figure 4. Global Storage resources by geography and by resource classification in the SPE Storage Resources Management System. The geographical distribution shows the combined undiscovered and sub commercial resources by country and region. In the classifcation graph, black bars show on a logarithmic axis global estimates for resources currently achieving the criteria for classification as undiscovered, sub commercial, commercial, and stored resources (Baines et al., 2022).
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5.2 Site development and engineering

Industry best practice for maturing storage resources from prospective to commercial has developed with project experience (Duong et al., 2019; Alcalde et al., 2021; Dean & Tucker, 2017; Ringrose 2018, 2020; Equinor, 2020). The Storage Readiness Level (SRL) is a recent framework developed to track the degree of maturation for specific sites (Akhurst et al., 2021). The process follows established workflows from the oil and gas industry and includes site screening, selection, and characterisation (National Energy Technology Laboratory, 2017). Typically the process will take 2-4 years.

Monitoring the CO_2 injection gives operators assurance that the project is in conformance, reduces uncertainties existing at the outset of the operation, and addresses societal concerns (Dean & Tucker, 2017; Barros et al., 2021). Monitoring plans need to balance cost-efficiency and value of information (Bourne et al., 2014). Geophysical techniques are indirect methods to interrogate the storage reservoir and monitor plume migration. Time-lapse seismic imaging is the most important geophysical technique for CO_2, but gravimetric and electromagnetic methods, and distributed fibre optic sensing have also been developed (Chopra & Castagna, 2014; Tveit et al., 2020; Pevzner et al., 2021). The observed plume can be used to confirm or update model predictions (Furre et al., 2017). Downhole pressure and temperature measurements at the injection well are used to monitor injectivity and detect leakage into overlying aquifers. Significantly, there are no commercial techniques for observing residual or dissolution trapping, which is currently addressed through simulation based history matching (Mykkeltvedt et al., 2012; Moghadasi et al., 2022).

Risk management is central to the planning and operational phases of CO_2 storage projects (Pawar et al., 2015). In practice the risk of unsustainable injection rates is the largest risk to a commercial project (Nicol et al., 2011; Guglielmi et al., 2021; Duguid et al., 2021). Site engineers have several tools and resources available to address risk, ranging from models and simulation, data acquisition, and geophysical monitoring. Storage projects expect a risk profile that decreases steadily during site planning, operation, and closure (de Coninck & Benson, 2014). If anomalies are observed, such as gas detected at the ground surface or seafloor, or unexpectedly rapid plume migration, a new evaluation of risks will determine if an operational change is needed (Dean et al., 2020; Waage et al., 2021; Glubokovskikh et al., 2020).

With increasing demand for storage, individual site development will need to be put in the context of a portfolio of storage sites (Figure 5). A portfolio of sites may be connected by a common aquifer and a pipeline distribution network (bp, 2022). This comes with additional challenges. Pressure communication and interference between sites can significantly impact the risk of injectivity and capacity loss at individual sites (De Simone & Krevor, 2021; Birkholzer et al., 2009). There may be need for regional scale pressure management (Bandilla and Celia, 2017; Cihan et al., 2015; Birkholzer et al., 2012). This will require forecasting pressure over space and time over scales well beyond that of any given site (Gasda et al., 2017; Pettersson et al. 2022). Uncertainty, data scarcity, and lack of acceptable regional scale models makes this difficult (Elenius et al., 2018).

5.3 Business models for carbon storage

Project costs and revenues are central to the deployment or failure of carbon capture and storage chains. Minimising costs associated with capture by obtaining CO_2 from high-purity sources, generating revenue from the sale of CO_2 for use in enhanced oil recovery, and minimising total project size are leading factors in project progression (Abdulla et al., 2020; Martin-Roberts, 2021; Wang et al., 2021).

The subsurface component of costs are well established for projects with capture and injection rates in the range 0.5 – 5 Mt CO_2 yr^{-1} and injection lasting between 10 – 30 years. Detailed cost models, regional storage cost supply curves, and Front End Engineering Design (FEED) studies covering a range of storage environments are publicly available (Rubin et al., 2015; Morgan & Grant, 2014; Shell UK Limited, 2016; ACT Acorn, 2018; Equinor, 2020; Smith et al., 2021; Torp & Brown, 2005). Over the life of a storage project, costs in 2020 values range USD $5-15 per tonne of CO_2 stored for storage onshore and USD $15 – 25 per tonne when storage is offshore. The leading cost components include site characterisation, the construction of wells, and site monitoring pre- and post-injection, primarily seismic imaging. To place this in context, capture costs associated with power production range from $30-100 per tCO_2 and transport costs range $1-5 per tCO_2 for every 100km distance (Smith et al., 2021; Rubin et al., 2015). As a result storage costs comprise 10-20% of the total CCS chain when CO_2 is captured from dilute flue gas streams, whereas they can dominate full chain costs when CO_2

is obtained from a high purity source such as natural gas processing, or when capture rates are below 500,000 $tCO_2\ yr^{-1}$ (Leeson et al., 2017; ACT Acorn, 2018).

Costs are recovered through a combination of government grants, policy support in the form of tax credits or avoided tax (Table 1), revenue from the sale of carbon credits, or the sale of CO_2 for enhanced oil recovery (Whitmarsh, 2022; Rassool et al., 2020; Herzog, 2016). When CO_2 is captured from low-purity streams like flue gas from power production, government supported capital grants have been required (Herzog, 2016). When CO_2 comes from high purity streams like natural gas processing or ethanol production, there are a number of demonstrated business models. In Norway, the Sleipner and Snøhvit projects are economic because the costs of storage are less than the cost of a tax imposed on CO_2 emissions (Torp & Brown, 2005). A number of storage projects in the USA have succeeded entirely from revenue from the sale of CO_2 for enhanced oil recovery, around \$30 tCO_2^{-1}, and now obtain tax breaks of a similar magnitude through the 45Q policy (Herzong, 2016). In Alberta, Canada, the Quest project obtains significant revenue through the generation and sale of carbon credits under the Technology Innovation and Emission Reduction regulation (Shell Canada Energy, 2021).

Business models are now emerging to overcome the barriers of costly infrastructure and expensive CO_2 capture from dilute emissions streams. The Norwegian government financed the Longship Project with capture and storage of 800,000 $tCO_2\ yr^{-1}$. The Northern Lights Joint Venture was awarded the role of the CO_2 transport and storage operator (Norwegian Ministry of Petroleum and Energy, 2020). There is extra injection capacity, up to 1.5 Mt yr^{-1}, and the Northern Lights project may sell this to other carbon capture operators. The UK government, similarly, is establishing a private transport and storage operator that will own an initial pipeline and storage infrastructure (UK Department for Business, Energy, & Industrial Strategy, 2021b). While initial capture projects will be government financed, the storage operator will subsequently generate revenue through a user-pays model where industries contract for the offtake of their CO_2 emissions.

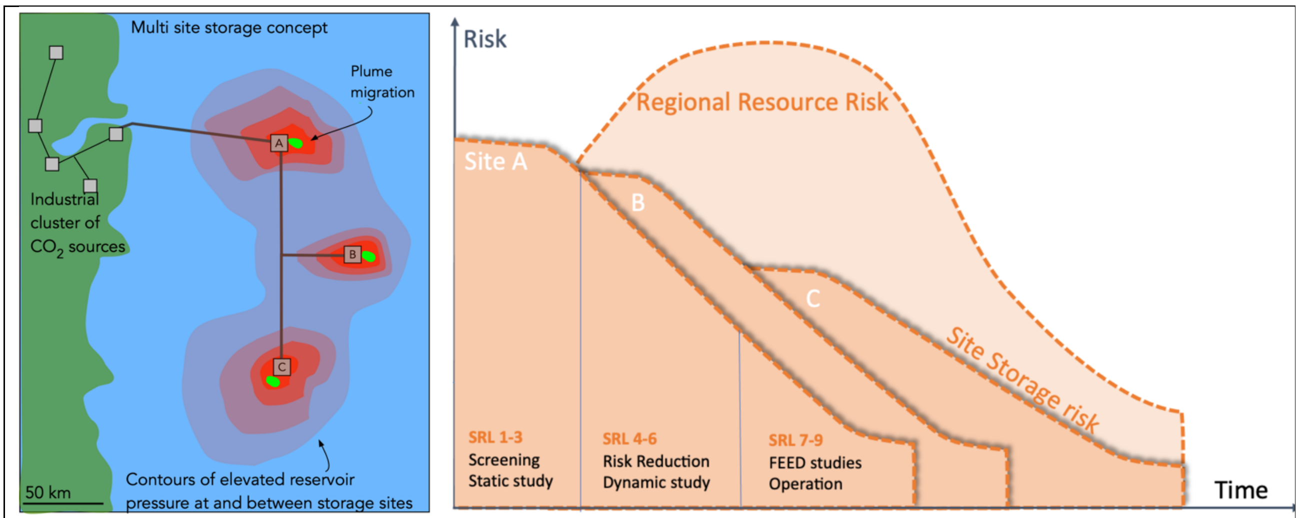

Figure 5. Left: Schematic offshore multi-store development with CO_2 derived from an onshore industrial cluster where sites A, B, and C are sequentially developed. Right: Schematic risk profiles for the individual sites and regional resource risk in aggregate as Storage Readiness Level (SRL) progresses. Knowledge gained from the development of earlier sites serves to de-risk subsequent development of sites in a region NOTE TO REVIEWERS: all figures are “mock-up” and will be professionally developed by NREE

5.4 Current deployment and scaleup to climate relevant injection rates

There are 26 commercial CO_2 storage sites operating around the world at injection rates between 0.5 – 2 $MtCO_2\ yr^{-1}$ (Global CCS Institute, 2021). This corresponds to a CO_2 capture capacity of around 40 Mt yr^{-1} (Figure 6). Between 200-300 Mt of CO_2 has been stored underground since 1996 (Zhang et al., 2022). These projects operate in a range of settings. Sleipner, the first dedicated CO_2 storage site, and Snøhvit are offshore and associated with natural gas production (Bicklet et al., 2007; Furre et al., 2017; Ringrose 2018, 2020). The In Salah, Quest, and Decatur projects are all onshore projects with storage in saline aquifers (Duong et al., 2019; Finley et al., 2014; Ringrose 2018, 2020). The remainder of projects are onshore with CO_2 injection into oil fields, with concurrent enhanced oil recovery.

Projects comprising over 100 Mt per year capture capacity have been announced in some stage of development, with injection planned to begin before 2030 (Global CCS Institute, 2021; IEA, 2021). A number of projects in the North Sea are designed around systems which allow access to multiple suppliers of CO_2. This includes the Aramis and Porthos projects offshore Netherlands, and the Northern Lights Project, offshore Norway. Business models involving static consortia include the Hynet (UK), Northern Endurance (UK) and Green Sands (DK) projects. Injection wells for CO_2 storage comprising between 15 – 30 Mtpa have recently been permitted in the USA indicative of the impact of policy support (EPA, 2022). Reviews of past project development suggests that many, if not most, of these projects may ultimately stop prior to injection taking place (Wang et al., 2021). However, the number of projects in development has been steadily increasing since a nadir in 2017, suggesting an upward trajectory of development (Global CCS Insitute, 2021).

Projections of future demand for CO_2 storage are found in techno-economic studies evaluating climate change mitigation, and government roadmaps for achieving greenhouse gas emissions reductions. For mitigation achieving less than 2^{o}C of warming, global storage rates scale up rapidly to on average 5-10 gigatonnes of CO_2 injection per year by 2050. These rates are sustained, resulting in 350 – 1200 Gt of CO_2 stored underground by 2100 (Huppmann et al., 2018; IPCC 2014, 2018, 2022). The UK Government has identified mitigation trajectories with scaleup of CO_2 storage to 75-175 Mt yr^{-1} by 2050. The European Union and the US Governments have identified trajectories with 2050 storage rates raning from 80-300 Mt yr^{-1} and 1 Gt CO_2 yr^{-1} , respectively, by 2050 (European Commission, 2018; U.S. Department of State, 2021).

A number of analyses suggest that this scaleup is not limited by geology or engineering. Well construction for oil and gas in the Gulf of Mexico and North Sea have achieved analogous rates of development sustained over decades (Ringrose & Meckel, 2019; Lane et al., 2021). Wastewater injection into deep sedimentary formations in the United States reached approximately 1.2 Gt in 2012 (Veil, 2015; Krevor et al., 2019). Regional and global scale analysis of pressure limitations suggests their impact will be limited to a few locations (Szulczewski et al., 2012; Vilarrasa and Carrera, 2015; De Simone and Krevor, 2021; Lane et al., 2021). Source sink matching suggests that the global distribution of suitable geology will facilitate regionally disperse use of CCS (Wei et al., 2021).

Achieving these trajectories requires high rates of growth for an infrastructure-intensive energy technology (Figure 6) (Zahasky & Krevor, 2020). Regional variation in historical oil production suggests that CO_2 storage rates in China and India may be even more limited (Lane et al., 2021). At the same time, current progress in CO_2 storage is commensurate with significant levels of mitigation. Annual storage rates of 30 Mt yr^{-1} achieved in 2019 are around half of the ~60 Mt of CO_2 equivalent emissions avoided from solar photovoltaic in the USA in the same year (Zhang et al., 2022; IRENA, 2019). The announced project pipeline is within the lower range of scenarios in IPCC projections for 2030 (Figure 6). Maintaining existing growth would lead to cumulative storage amounts by 2100 commensurate with 1.5^{o}C mitigation pathways (IPCC, 2018; Zahasky & Krevor, 2020).

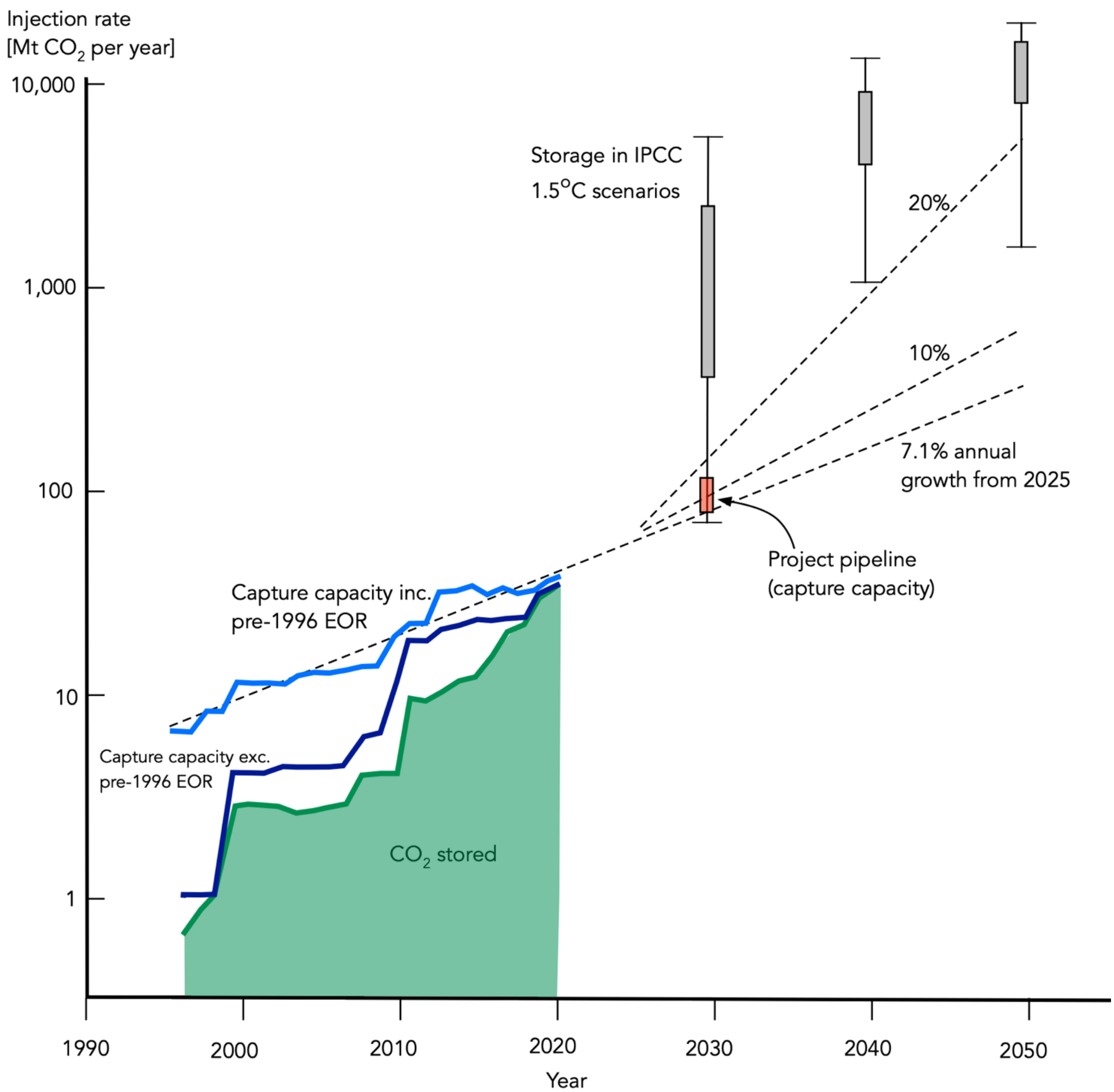

Figure 6. Current deployment, project pipeline, exponential growth trajectories, and storage rates in techno-economic scenarios synthesized by the IPCC

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6. Summary and future Perspectives

Industrial scale CO_2 storage is demonstrated in a variety of geological settings and is making a significant contribution to climate change mitigation today. The understanding of the geology of CO_2 stores has evolved beyond simple analogue to oil and gas systems to a variety of settings with complex geology and plume immobilisation achieved through both the use of geological structures and residual trapping. Studies in fluid dynamics have identified the key controls of buoyancy, small scale reservoir heterogeneity, and residual and dissolution trapping on plume dynamics. The understanding of seismic risk during CO_2 storage has benefit from experience in managing seismicity associated with wastewater injection in the United States, highlighting the importance of site selection in mitigating seismic risk. Hydrogen storage underground has emerged as a prospect for terawatt scale energy storage, and can benefit from a range of geophysical similarities to both subsurface CO_2 and natural gas storage.

In socio-economic dimensions, the potential contributions of CCS to environmental sustainability are demonstrated at the single site scale, including support for the permanence of stored CO_2 and lifecycle climate benefits of the entire CCS chain. Leading public concerns around technical aspects of CCS are related to the subsurface including leakage and seismicity. Other leading concerns include a continued dependance on and legitimization of fossil fuel technologies, and a deferment of investments in renewable technologies. Legal instruments at international, national, and sub-national levels have been developed and facilitate successful project deployment.. Carbon storage project development must be tailored to the local societal context to ensure public acceptance.

There are few engineering limitations to the near term scaleup of CO_2 storage. Engineering tools including site development, management, and plume monitoring are mature. Similarly, storage resource assessment and classification is mature. Successful business models exist today where project cost recovery through revenue from enhanced oil recovery, carbon credits, and tax schemes of \$30 tCO_2^{-1} is possible in association with CCS chains capturing CO_2 from high concentration sources.

At the same time there are key areas where further development would support or is necessary for the scaleup envisioned over the coming 30 years. The progress in understanding the reactive fluid dynamics of subsurface CO_2 offer the promise of accurate predictive and history-matched modelling of plume behaviour. An evolution is underway in managing seismic risk, moving from the reactive traffic-light system towards a more sophisticated approach analogous to history matching in plume management. These advances would enable significant risk and cost reductions in the operation of sites. Subsurface hydrogen storage is comparatively little studied, but experience with CO_2 storage can guide approaches for efficient resolution of unknowns around the fluid flow properties, the impacts of cycling on store integrity, and the management of microbial degradation of stored H_2.

There are many uncertainties that arise from the scale of envisioned storage. At these scales, resource use expands well beyond the consideration of single sites to entire basins. New tools will be required to characterize these systems, and optimize resource development and management at regional scales. At gigaton scales, leakage rates must be kept to on average <.01% annually, but approaches for monitoring and verifying storage to this precision have not been developed. Business models supporting more expensive project chains have yet to be demonstrated. Techno-economic modelling shows that CO_2 storage with enhanced oil recovery can be a contributor to climate change mitigation, but there are questions about the environmental benefits and societal acceptability. Given the extent of policy and financial support likely required, major efforts must be made to increase both public awareness and societal acceptability. Model projections of the large and rapid scaleup of CCS should be revisited with more realistic constraints placed on growth trajectories, based on historical analogues and known geophysical limitations.

Thus CO_2 storage sits at a crossroads. It has developed to sufficient scale and varying contexts that it is as well placed as any low carbon energy technology to be considered in projections of future energy systems. The magnitude of its role, however, is far from certain, and the evolution from megatonne to gigatonne scale presents at least as many challenges as have yet been overcome.

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9. Competing interests

The authors declare no competing interests

10. Author contributions

All authors contributed to writing the introduction, summary and future perspectives, and reviewing and editing the manuscript
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§ Economics was principally written by: SK
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