CARBON SEQUESTRATION LEADERSHIP FORUM (CSLF)

TECHNICAL GROUP

TASK FORCE ON

IMPROVED PORE SPACE UTILISATION

# Improved Pore Space Utilisation: Current Status of Techniques

APRIL 2019

# Executive Summary

At the 2015 CSLF Ministerial Meeting in Riyadh, Saudi Arabia, a Task Force was formed to investigate Improved Pore Space Utilisation. The Task Force mandate was to investigate the current status of techniques that have the potential to improve how well the capacity of reservoirs for $CO_2$ storage are utilised. This document is a summary of this investigation.

This investigation represents a review of the current status and potential for various technologies to improve Pore Space Utilisation and does not necessarily represent the views of individual contributors or their respective employers.

For CCS to achieve the required contribution to the Paris Agreement's aim to keep the global temperature increase from anthropogenic carbon dioxide ($CO_2$) emissions to 2°C or below, the annual $CO_2$ storage rate needs to increase dramatically (from < 40 in 2018 to 2,400 million tonnes per annum storage by 2035). Internationally, this requires a significant increase in CCS infrastructure development, as recommended in the CSLF Technology Roadmap (2017a). Present progress towards CCS infrastructure is not on target, and strong actions are required to rectify this.

Better utilisation of 'investment ready' storage resources and 'discovered' resources is recommended to potentially improve the path towards the 2035 target, and broadly to significantly improve the economics of the CCS projects.

The pore space of a $CO_2$ storage system is the 'resource' to a $CO_2$ storage site operator. Presently, the efficiency of the storage resource is quite low, with only 1 to 4% of the bulk volume being utilised to store $CO_2$ in saline formations. A poor utilisation of this pore space resource means that the resource is wasted, and the opportunity to reduce the cost per tonne of $CO_2$ stored is significantly hindered. Conversely, a resource that is effectively utilised is likely to significantly improve the economics of CCS projects.

From a non-technical basis, the issue of effective storage space utilisation, including when competing subsurface uses exists, has been reviewed. While jurisdictions managing $CO_2$ storage on this first-come first-serve basis has short to medium term sustainability, competition for the pore space is likely to become an issue as CCS matures. A strategically managed approach is recommended in certain scenarios of future $CO_2$ storage, particularly for regions with multiple or connected storage options. To ensure effective utilisation of the pore space resource, a degree of pre-competitive characterisation would also be required including a detailed techno-economic evaluation of the storage region. This evaluation would include injection rate, cost, risk minimisation, multi-resources and would need to be considered within the framework of government energy policies.

This task force has included a review of mature capabilities from the petroleum sector in improving hydrocarbon sweep efficiency, including enhanced oil recovery techniques. This review found strong applicability in the use of foams as physical barriers in high permeability streaks to encourage better vertical sweep, and potential also for the application of polymers and surfactants to modify flow properties in $CO_2$ storage.

Four evolving technologies were reviewed as potential methods for improving the utilisation of pore space associated with $CO_2$ storage:

1. Pressure Management
2. Microbubble $CO_2$ Injection
3. $CO_2$ Saturated Water Injection & Geothermal Energy
4. Swing Injection

Combined with existing petroleum sector techniques, these technologies were reviewed in terms of prior R&D and application, technical readiness for commercial deployment, and the prospectively of the technology in improving pore space utilisation. All technologies reviewed represent strong value to the optimisation of site storage operations, yet many of them require further technical development before they could be deployed at scale commercially. A recommended action for the technology development is given for each technology.

*Comparison table of pore space utilisation technologies. Technologies are ranked in order of priority (column 'P') for continued technology maturation. Green indicates high perspectivity for the technology, light green less urgency, while orange indicates lower technology prospectively broadly, yet strong niche opportunity.*

| P | Technology Type | Prior R&D and application | Technology Readiness Level (TRL) | Technology Prospectively |
|---|---|---|---|---|
| **1** | Microbubble $CO_2$ Injection | Laboratory and Modelled, prototype | TRL 4 | High potential |
| **2** | Swing Injection | Laboratory and Modelled | TRL 3 | High potential |
| **3** | Increased Injection Pressure | Laboratory and Modelled | TRL 3 | High potential |
| **4** | Active Pressure Relief (increase sweep & reduce lateral spread) | Enhanced Oil Recovery (EOR), planned for Gorgon $CO_2$ injection project | TRL 6 | High potential |
| **5** | Foams (block high permeability pathways) | EOR | TRL 6 | Reasonably well understood |
| **6** | Passive Pressure Relief | Modelled | TRL 4 | Limited effectiveness |
| **7** | Polymers (increase formation water viscosity) | EOR | TRL 7 | Reasonably well understood |
| **8** | Surfactants (reduce residual saturation of formation water) | EOR | TRL 7 | Reasonably well understood |
| **9** | $CO_2$ saturated water injection & geothermal energy | Laboratory and Modelled | TRL 3 | Site specific & lower volume |

* minor modelling and laboratory investigations may be required prior to commercial scale application

# Contents

# Acknowledgements

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# 1 Introduction

The priority recommendation of the CSLF Technology Roadmap (2017a) is for CCS to have achieved a storage rate of at least 2,400 Mt of $CO_2$ per year by 2035, to ensure that CCS contributes its share to the Paris Agreement's aim to keep the global temperature increase from anthropogenic carbon dioxide ($CO_2$) emissions to 2°C or below.

18 large-scale $CO_2$ geological storage projects are presently in operation internationally, with a further five under construction, and 20 in various stages of development (Global CCS Institute, 2018). Together these facilities are storing almost 40 million tonnes (Mt) of $CO_2$ per year. These $CO_2$ injection projects include storage into saline formations for permanent storage including the Sleipner, Quest, Illinois Industrial CCS, and Snøhvit projects; and into producing oil fields for $CO_2$- enhanced oil recovery (EOR), including the Weyburn, Abu Dhabi CCS, and Petra Nova projects (source: Global CCS Institute).

These $CO_2$ storage projects have proven very effective in the safe storage of commercial quantities of $CO_2$. Presently however, these saline formation storage projects do not approach the technical storage capacity limit, nor do they have the onus to increase the rate of storage. Further, oil produced from $CO_2$-EOR projects carries a $CO_2$ footprint of 0.43 t $CO_2$ per barrel, in effect reducing the net $CO_2$ pore space utilisation (EPA, 2016). Technical solutions do exist to maximise $CO_2$ storage in an advanced $CO_2$-EOR operation so that net negative $CO_2$ emissions (Lipponen, 2015), yet this approach presently lacks a strong economic case to do so commercially.

For CCS to achieve the required targets for the Paris Agreement's aim, the annual net volume of $CO_2$ storage and abatement needs to increase dramatically (~60-fold by 2035). This will require many new commercial scale storage projects, and there are a number of efforts internationally to bring new CCS projects on line. In addition, being able to improve the utilised storage capacity of these new (and existing) projects could significantly improve the economics of the CCS projects.

## 1.1 Background

### Initial "raison d'etre" as Presented to CSLF Ministerial Meeting

*With straightforward $CO_2$ injection, in particular when storing in saline formations, a large portion of available pore space in a geological storage site is bypassed, or storage rate is limited by pressure build up. Utilised storage capacity is typically about two orders of magnitude lower than the pore space resource (the United States Department of Energy (DOE) estimate this efficiency factor to be ~1-4 % of the pore space resource for saline formations), and in many cases a resulting large lateral spread of $CO_2$ requires costly monitoring relative to the volume stored. Being able to improve pore space* *utilisation may be very beneficial in terms of increased storage capacity, reduced monitoring costs, and increased ability for 'hub[1]' style storage operations.*

The pore space of a $CO_2$ storage system is the 'resource' to a $CO_2$ storage site operator. A poor utilisation of this pore space resource means that the resource is wasted, and the opportunity to reduce the cost per tonne of $CO_2$ stored is significantly hindered.

Typically, $CO_2$ injected into saline formations will rapidly migrate to the top of the reservoir unit due to buoyancy, and then migrate laterally, following dip along the base of the primary seal. The bulk of the reservoir rock's pore space is bypassed due to the rapid buoyant rise of the $CO_2$. Projects such as Sleipner, designed in a similar manner to hydrocarbon production in its early years (i.e. without significant integrated reservoir management techniques) show this effect. In this project, only a small fraction of the available pore volume in these storage sites is utilised for $CO_2$ storage due to both buoyancy and uneven $CO_2$ distribution due to "fingering" where large areas have not been penetrated by $CO_2$ at all.

Added to this is the large areal extent of the $CO_2$ plume, as volumetrically the $CO_2$ plume would be thin yet have a wide areal extent. A large areal extent could in some circumstances increase the probability of leaks along intersecting faults, abandoned wells, and other permeable zones in the seal. Therefore, pre-injection appraisal will need to be more extensive and monitoring strategies must cover large areas.

Much effort has been spent by the technical CCS community in improving the estimation of storage resource. These have resulted in publications providing methodologies for the estimation of storage resource of $CO_2$ in saline aquifers, hydrocarbon reservoirs and coal seams. These include the 'Methodology for Development of Carbon Sequestration Capacity Estimates' prepared for the National Energy Technology Laboratory, U.S. Department of Energy (US DOE, 2006), and the 'Estimation of $CO_2$ Storage Capacity in Geological Media – Phase II' prepared for the Carbon Sequestration Leadership Forum (CSLF, 2007). These two methodologies have since been compared by CSLF (CSLF, 2008) and by the CO2CRC Ltd. in 2008 (CO2CRC, 2008). Recently the Society of Petroleum Engineers (SPE) has addressed inconsistency with the development of a Storage Resource Management System (SRMS), improving the confidence regarding pore space resource assessments for $CO_2$ storage. The SRMS was applied to regional storage assessments for North America, the UK, Norway, China, Brazil, Australia and the Indian Subcontinent, to re-assess $CO_2$ storage capacity estimates. Of the 12,000 gigatonne total storage resource, enough work has been completed to mature only ~750 MT into 'investment ready' storage resources.

These studies have led to significantly improved global storage estimates and highlight two very important facts:

1. 'Investment ready' storage resources, whilst currently an order of magnitude higher than present day storage rates, are small relative to the target storage rate of 2,400 MT by 2035. Effort is required to increase the 'Investment ready' storage resource.

[1] Hub – A single storage location where $CO_2$ is transported from a range of different $CO_2$ sources.

2. Utilisation, or storage efficiency, into the existing 'Investment ready' storage resource must be optimal.

Presently, storage efficiency, the proportion of pore space utilised, is very low. In the case of saline formations (with a 15 to 85% confidence), $CO_2$ storage efficiency represents between 1 to 4% of the bulk volume. Storage efficiency is higher in depleted petroleum fields, however, to meet the required $CO_2$ storage targets, these large saline formations form the basis for Improved Pore Space Utilisation review.

Economies of scale dictate that the better the utilisation of a resource the more cost-efficient an operation (unless the cost of advanced utilisation outweighs the benefit). The capital cost of a pipeline, and development of a storage site, in most cases, would be further offset if the pore space utilisation is enhanced. The scale of the site to be appraised and monitored, including number of wells and impact to land owners, would be significantly reduced, if the pore space utilisation is enhanced.

The purpose of this task force study is to examine options to improve the utilisation of the pore space resource. This study considers modifying the manner of $CO_2$ injection to better utilise the resource. The key challenges for better utilisation of the resource addressed in this study are associated with overcoming the effect of buoyancy, improving the residual trapping process, and increasing the rate of transition from free-phase to dissolved phase.

This includes the examination of existing technologies developed in the hydrocarbon industry, maturing pressure management technology, and innovative emerging technologies, as well as general principles for storage operations.

1. Improved sweep efficiency techniques from the oil and gas sector
2. Pressure management
3. Microbubble injection
4. $CO_2$ saturated water injection combined with geothermal energy production
5. Compositional, temperature and pressure swing injection

This report **does not** go into details around well design (well orientation, number of wells, perforation, flow controls, well switching, etc), as these approaches are site specific and are reasonably well understood in the petroleum industry. However, the authors do recommend a future investigation of key learning from existing well design and well operation practices for improving reservoir utilisation.

The report also **does not** address any technical concepts regarding reservoir stimulation to increase utilisation. The authors see these as unnecessary techniques at the present level for the CCS industry, and present unnecessary risk in terms of long–term, safe $CO_2$ containment.

## 1.2 Storage Efficiency

The storage efficiency is a key parameter which describes the proportion of pore volume within the target storage complex reservoir volume that can be filled with $CO_2$ given the development options considered.

This ranges from 2 to 5% in some open aquifers without structures, through to 70-80% in highly depleted gas fields (see Figure 1 for an example from the UK). It is broadly the equivalent of recovery factor in the oil and gas industry.

The lifecycle unit cost of $CO_2$ transport and storage developments is complex and dependent upon many factors. The influence of some factors such as the length of the pipeline or the number and depth of wells required are both obvious and clear. Factors such as the volume of $CO_2$ stored in any project are equally important but often less obvious. Whilst storage efficiency is less well understood than other factors, it is a fundamental influence on overall lifecycle costs. Storage efficiency is high in pressure depleted gas fields which means that a large mass of $CO_2$ can be stored safely in a relatively small area. This means fewer platforms and wells and lower monitoring costs.

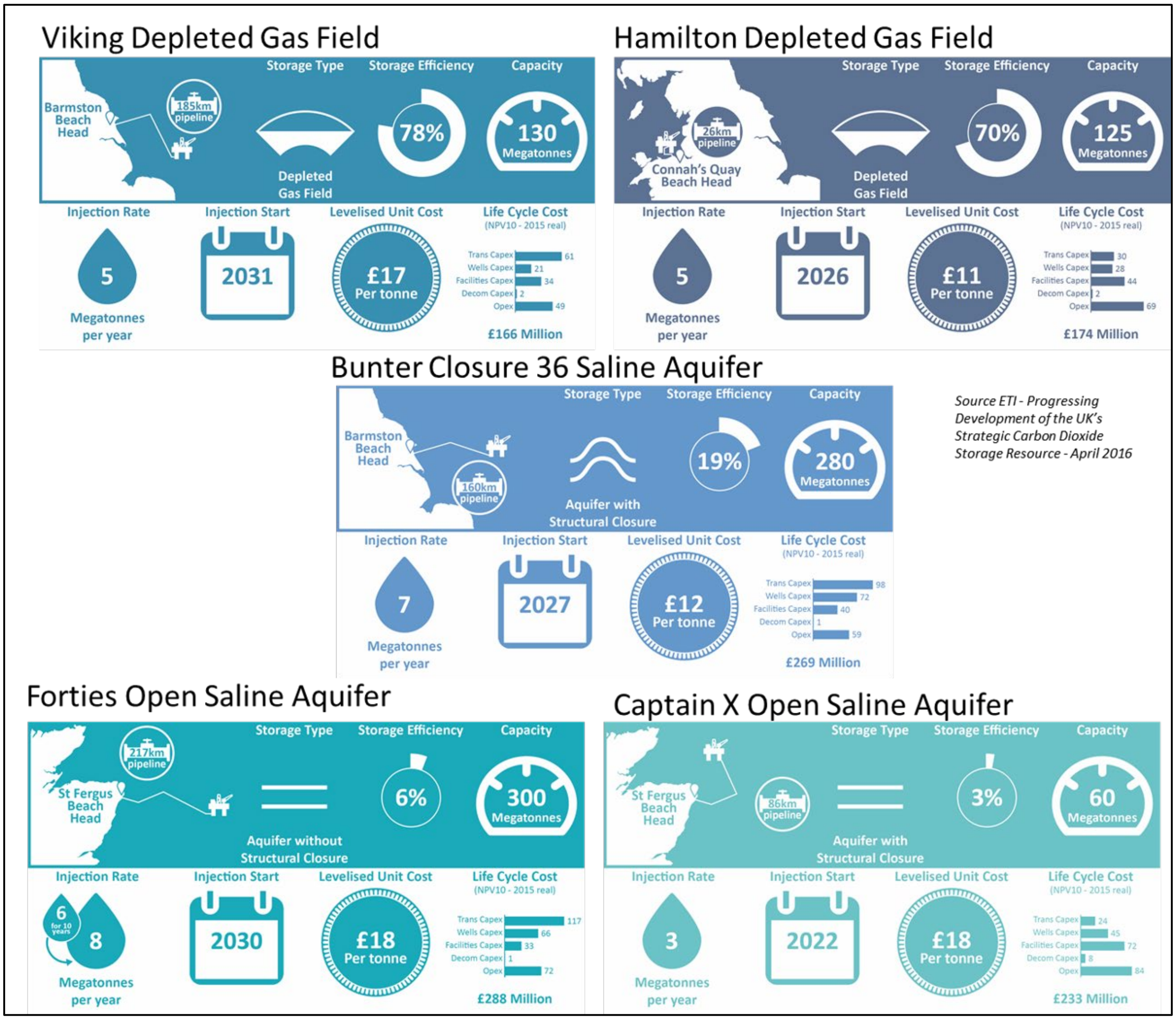


*Figure 1: Source ETI - Progressing Development of the UK's Strategic Carbon Dioxide Storage Resource - April 2016. A clear difference in storage efficiency is noted between the depleted gas fields (70 – 78%) to the saline aquifers (3 – 19%)*

## 1.3 Dynamic Capacity

The dynamic capacity of the formation also plays an important role in how much of the pore space can be ultimately utilised. While there are cases where high storage efficiency can be achieved, a rapid build-up in pressure due, in some saline formations, to the injection of $CO_2$ results in much of the overall pore space resource not being accessed. An understanding of the dynamic capacity is therefore required to plan an appropriate injection rate and number of injection points to manage pressure build up whilst utilising the site effectively.

There are two methods for assessing $CO_2$ storage capacity:

1. Static (independent of time and including volumetric estimates using pressure build-up data)
2. Dynamic (where properties vary with time and include analytical approaches and numerical simulation) as defined by Pickup, 2013.

These methods are summarised in Table 1.

*Table 1 Summary of static and dynamic capacity methods (after Pickup, 2013)*

| | Method | Summary |
|---|---|---|
| Static | Volumetric | Calculate formation pore volume<br>Assume a storage efficiency<br>Simple approach |
| | Pressure build-up | Assume a closed system<br>Estimate the maximum allowable pressure build-up<br>Calculate $CO_2$ volume from total compressibility and pressure increase |
| Dynamic | Semi-closed | Similar to pressure build-up method, but allows water to leak through the seals<br>Does not assume zero permeability in seals<br>Assumed $CO_2$ will not leak out because capillary entry pressure too high |
| | Pressure build-up at wells | Assumes pressure at injection well is the limiting factor<br>Uses an analytical formula to estimate the injection pressure<br>Assumes average pressure build-up throughout aquifer<br>Assumes homogenous aquifer and sharp interface between $CO_2$ and brine |
| | Material Balance | Similar to the pressure build-up method, but update calculations with time |
| | Decline curve analysis | Monitor pressure build-up in a $CO_2$ injection site<br>Opposite of decline curve analysis in a hydrocarbon reservoir<br>Injection rate gradually declines as pressure builds up |
| | Reservoir simulation | Construct a detailed geological model<br>Perform fluid flow simulations<br>Requires most data and is the most time-consuming method |

Dynamic $CO_2$ storage capacities are estimated using a 3D model that incorporates a structural framework with information such as porosity, permeability and geological formation character. Dynamic simulations using this model are then required to make the capacity estimate by utilising information about the effects of dynamic variables such as the number of wells, length of injection, rate of injection and the time to inject a given mass of $CO_2$ into a target storage volume. Temperature, pressure and total dissolved solids (TDS) data can also be used in the models to determine fluid properties such as $CO_2$ density, viscosity and dissolution coefficients (Gorecki *et al.* 2014). There is a risk that storage capacities could be overestimated if dynamic conditions are not applied and the properties of open and closed formations are not considered. These numerical simulations can be used to assess pressure build-up in order to help with the design of injection strategies (Babaei *et al.* 2016).

The size of the storage site and the type of boundary is of importance, for example in a small closed aquifer injected $CO_2$ will quickly reach the boundary and the $CO_2$ must be accommodated by compressibility of the formation and water (Bachu, 2015). In an actual storage site in this scenario the maximum pressure is likely to be reached around the injection wells or at the shallowest part of the structure and the pressure is limited by regulatory agencies to a percentage of the fracture pressure (Bachu, 2015).

## 1.4 Residual Trapping

There are several $CO_2$ trapping mechanisms which operate over different time scales: structural/stratigraphic and hydrodynamic trapping; residual trapping (capillary trapping); dissolution/solubility trapping; and mineral trapping (Bachu *et al.* 2007, Holloway *et al.* 2006).

Residual trapping, along with dissolution and mineral trapping, occurs over longer timescales than structural/stratigraphic and hydrodynamic trapping. These trapping mechanisms are an important aspect of storage security and safety when storing $CO_2$ in geological formations and primarily occur once injection into the storage formation has ceased (Bachu *et al.* 2007, Gorecki *et al.* 2014, Juanes *et al.* 2006). Recent studies suggest that up to 90% of the total storage capacity may be associated with residual trapping which will affect the extent of plume migration within the reservoir (Warwick, 2013; Nui *et al.* 2015). Research at the Frio Brine pilot study, USA, estimated that residual trapping for the conditions encountered there accounted for approximately 30% of the injected $CO_2$ (Horvorka *et al.* 2004).

Residual trapping has been extensively researched in the field of hydrocarbon exploration, mainly because it influences the ultimate oil recovery during production processes. When water is injected to enhance the recovery of hydrocarbons, there will ultimately be residually trapped oil remaining and this provides an analogue for residual trapping in $CO_2$ storage capacity (Nui *et al.* 2015).

As the injected $CO_2$ moves through the pore space of the formation it migrates upwards under buoyancy-driven flow and continues to do so after the cessation of injection. In most cases the pore space that $CO_2$ is injected into is naturally water-wet (wetting-phase) and the $CO_2$ being injected into the reservoir is a non-wetting phase (Juanes *et al*. 2006). When $CO_2$ enters the pores, some of the pore fluid remains in place (i.e. not all of it is displaced). As the plume continues to migrate through the formation, some of the pore space that the $CO_2$ occupied is refilled by the pore fluid. As the $CO_2$ is displaced at the trailing edge of the $CO_2$ plume, snap-off/disconnection of small amounts of $CO_2$ (part of a process known as imbibition) may occur (Juanes *et al.* 2006). These disconnected fractions of $CO_2$ are immobile and remain in pore spaces isolated from the main plume and is known commonly as residual trapping (Bachu *et al.* 2007; Juanes *et al.* 2006; Nui *et al.* 2015; Zuo and Benson, 2014).

Bachu *et al.* (2007) link residual trapping to hydrodynamic trapping because of its relationship with a migrating plume of $CO_2$. Their definition of residual trapping is '*the irreducible gas saturation left in the wake of a migrating stream or plume of $CO_2$ when water moves back into the pore space, after it was expelled from the pore space by the injected and/or migrating $CO_2$*'.

They present the following equation for storage capacity in residual-gas traps:

$$\mathbf{V_{CO2t} = \Delta V_{trap} \phi S_{CO2t}}$$

Where:

**$V_{CO2t}$** is the theoretical volume available for $CO_2$ storage

**$\Delta V_{trap}$** is the rock volume previously saturated with $CO_2$ that is invaded by water

**$\Phi$** is the formation porosity

**$S_{CO2t}$** is the trapped $CO_2$ saturation

It should be noted that, because residual trapping is time dependent, the amount trapped by this method can increase over time while the $CO_2$ plume continues to migrate (Bachu *et al.* 2007) and the trapped $CO_2$ saturation (**$S_{CO2t}$**) and the rock volume (**$\Delta V_{trap}$**) can only be determined using numerical simulations (Juanes *et al.* (2006); Bachu *et al.* 2007).

Juanes at al. (2006) created simulations of injection and migration of $CO_2$ in a reservoir, one of the models assumed that all the injected $CO_2$ would migrate vertically as one plume with no residual $CO_2$ trapped. This model assumes a gas cap is formed under the cap rock creating the seal for the reservoir. A different scenario assumed there would be $CO_2$ residually trapped in pore spaces at the tail end of the migrating plume. This model predicted that after 500 years or less almost all the $CO_2$ is trapped within the geological formation and the $CO_2$ is spread over a larger area within the reservoir (differing from the first model which would have a concentrated plume of mobile $CO_2$). The second model is assumed to be more realistic and is likely to be more advantageous for storage of $CO_2$ by lowering the risk of leakage due to the presence of less mobile gas and increasing the chances of dissolution or mineral trapping (Juanes at al., 2006; Bentham & Kirk, 2005). Juanes at al. (2006) also conclude that high-resolution models are necessary to make an accurate assessment of the different storage/trapping mechanisms, if the model is too coarse it can result in an over-estimate of the sweep through the formation and the subsequent capillary (residual) trapping.

# 2 Non-Technical Issues Related to Improved Pore Space Utilisation

Current regulations concerned with $CO_2$ capture and storage (CCS) mean that the licensing of $CO_2$ storage sites is likely to be undertaken on a first-come, first-served (FCFS) basis. Applications for licenses of individual projects are submitted to regulators and the basis of the regulators' assessment will be primarily to consider if the site is fit for purpose as a storage site for $CO_2$ and is designed to protect the interests of pre-existing users. The following summary on storage resource optimisation is based on an IEAGHG report (2014), 'Comparing Different Approaches to Managing $CO_2$ Storage Resources in Mature CCS Futures'.

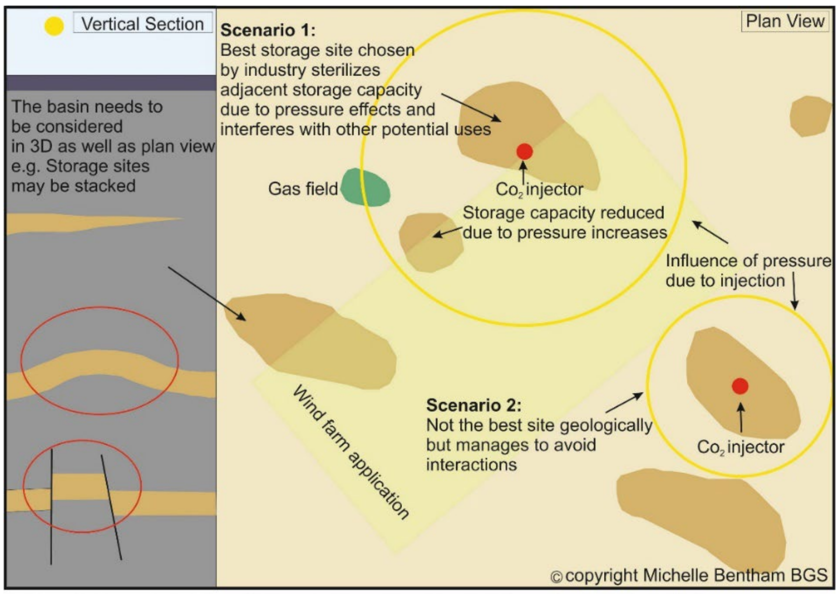


*Figure 2: Conceptual view of spatial and subsurface interactions which might limit storage site selection, using a hypothetical example of gas fields and two storage site scenarios in the UK Southern North Sea*

Storage sites for $CO_2$ will be selected by the operators on a 'most economically advantageous' basis, to meet the needs of individual clusters of CCS projects. Another IEAGHG study (2013), 'Interaction of $CO_2$ storage with subsurface resources', highlighted that sedimentary basins have multiple potential uses – hence there is potential for $CO_2$ storage projects to conflict with other subsurface and surface users (example shown in Figure 2). This report showed that increased pore fluid pressure in any reservoir formation (resulting from the injection of $CO_2$) may reduce storage capacity and increase costs in adjacent sites, which could potentially reduce the efficient use of the storage resource. Therefore, a more strategic approach would be required when dealing with sedimentary basins to ensure such formations realise their full resource potential. This raises important questions, including:

- How can $CO_2$ storage capacity be fully utilised in the presence of potentially competing uses of the subsurface and overlying ground surface or seabed?
- How should storage boundaries be defined in potentially pressure-interacting projects?

- How should potentially interacting resources e.g. $CO_2$ storage, hydrocarbon exploration and production and natural gas storage be developed most economically in the light of national or jurisdictional policies?

Factors which may influence the optimisation of a basin include the cost, risk minimisation, access to a range of uses of the basin including the ground surface and seabed, and the value of the resource. Such factors would need to be considered within the framework of government energy policies. It may also be necessary to look at other, perhaps less tangible potential future uses of the basin.

It is crucial for the operator and regulator to understand the consequences of a pressure increase over an area much larger than the extent of the $CO_2$ plume itself. It makes sense that an overview of the region (including future uses of the subsurface) is the responsibility of the relevant authority. The operator should be responsible for simulating the extent of the pressure footprint and the regulator for assessing the validity of this modelling. The main benefit of a FCFS approach is that the operator has the final decision on where to develop $CO_2$ storage, and the approach should work for multiple-stacked sites. Potential drawbacks of this approach include possible reduced storage capacities (in adjacent future storage sites), difficulties for monitoring and a lack of regional storage optimisation. In addition, the FCFS methodology may not lead to a pathway of overall least cost development for storage. To avoid or reduce potential negative interactions, some strategy management is likely to be necessary in most regions.

## 2.1 UK Regulations and Southern North Sea Case Study

The 2012 UK CCS Roadmap noted that the UK has extensive storage capacity in the North Sea and clusters of power stations/industrial plants which could share knowledge and infrastructure to develop $CO_2$ storage. At the time the storage roadmap set out specific activities that the UK government would focus on. This has been recently (November 2018) reset through the publication of the 'Clean Growth The UK Carbon Capture Usage and Storage deployment pathway An Action Plan' (UK Government, 2018) The UK Government has undertaken several significant activities for storage research and demonstration (R&D) including a commercialisation competition, the 2016 UK storage appraisal project (ETI, 2016) and a coordinated research, development and innovation programme.

UK-specific case studies described in the IEAGHG (2014) report illustrate the range of potential users/ conflicts which could be anticipated as more storage sites are developed. The main classes of potential $CO_2$ storage sites used are saline water-bearing domes in the Bunter Sandstone formation; gas fields in the Bunter Sandstone; gas fields in the Leman Sandstone; and gas fields in Jurassic limestones. Potential users or conflicts identified in IEAGHG's report include hydrocarbon operations, gas storage and other CCS sites (all subsurface users), and wind farms, dredging areas, pipelines, other operators, environmental protection areas and shipping routes (surface users). Scenarios were developed (FCFS and managed storage resource) to run from 2020 to 2050, to illustrate the interactions that may occur because of $CO_2$ injection.

The managed storage resource scenario demonstrates that CCS could face competition from other nearby CCS projects, offshore wind farms, gas storage sites and hydrocarbon production operations; however, it is likely that the development of both options could occur as demand for storage capacity increases, for reasons explained in the report. For example, offshore wind farms could present a physical barrier to accessing any potential storage sites in terms of laying down infrastructure and monitoring above a site, including the safety zones that may be imposed around turbines.

## 2.2 Underground Storage Permitting for $CO_2$ in the Netherlands

There are many R&D efforts underway in the Netherlands, and the national government works along an organisational model of a privately-run CCS market (where the initiative for action comes from the emitting operators themselves) and the government's role is one of a supervisor. It is interesting to note that the 'Inpassingsplan' (July 2008) under the Spatial Planning Act gives the Dutch government the right to adapt spatial planning by district/local governments in the circumstance of projects of national importance. The Dutch subsurface contains numerous gas fields and the policy of government is aimed at the use of depleted gas fields as $CO_2$ storage facilities.

There is the potential for competition within the surface and subsurface in the Netherlands. Using existing infrastructure is much more favourable than drilling new wells, but additional issues at the surface may arise, including land use conflicts, potential ground movements and induced seismicity. Public acceptance is likely the biggest barrier to $CO_2$ storage in the Netherlands and for this reason, at this stage it is only being considered offshore. In the subsurface, competition between users may arise in an onshore environment, where the storage of $CO_2$ may theoretically prevent gas fields from being used for other storage. Other potential competition in onshore areas may arise from nearby geothermal producers and injector pairs, or salt production activities from layers directly above the storage reservoir. A key potential offshore conflict is the issue of connectivity and pressure communication with adjacent fields under development or production.

## 2.3 Managing the Pore Space in Alberta, Canada

There are various activities and legislations to enable CCS and the storage of $CO_2$. The Alberta government assumes long-term liability (a significant uncertainty for CCS) for a storage site once a closure certificate has been issued, thus improving the ability for operators to plan/execute and ensuring the protection of the public. Steps have already been taken by the government to manage the positive and negative interactions between CCS and hydrocarbon resources. It is explicitly mandated in legislation that 'CCS projects will not interfere with or negatively impact oil and gas projects in the province'. The 'pore space tenure' process is the primary process to ensure that CCS development will not negatively impact the hydrocarbon industry in any way. Where there is high demand for pore space tenure in an area where pore space tenure has already been allocated, the provincial government must introduce policy and regulations to incentivise operators to allow access to their pore space for the storage of $CO_2$. There are currently no regulations for this, but portions of some Acts allow for the transfer of tenure and for Alberta, it is clear that 'market considerations should be a primary driver behind third party access to sequestration tenure and $CO_2$ injection'. The Albertan energy regulator has a well-developed process for evaluating and managing subsurface resource interaction, another process to encourage development in CCS.

## 2.4 Conclusions & Recommendations

There are various approaches to storage management, which are highly dependent on the jurisdiction involved. Most commonly, jurisdictions manage their pore space on a FCFS basis, in which operators will be able to identify their preferred $CO_2$ storage site. The operators' decision on a preferred site will be based on their specific geological, technical and financial criteria.

Management of storage on this FCFS basis is likely to be sustainable in the short to medium term especially in areas with abundant storage potential. However, there will be competition for the pore space in all regions; an issue likely to become more pronounced as CCS develops and matures, particularly in systems where pressure build is high. In some jurisdictions there is already a determined hierarchy of uses or constraints, but it must be noted that in some countries onshore storage is not considered due to public acceptance issues. Because of this, planning frameworks have already been developed to some extent in many countries considering the deployment of CCS. A strategic managed approach to a large formation or regional area may be desirable in certain scenarios of future $CO_2$ storage. The costs and benefits of such approaches have not yet been established, so studies that evaluate methods to optimise infrastructure for exploration will become increasingly important.

To understand the potential consequences of multiple storage scenarios occurring at the same time, a regional storage characterisation is recommended. Clusters of storage sites could be developed where regions have multiple or connected storage options. However, there is a current knowledge gap, and related policy approach, to determine the amount of pre-competitive characterisation needed to help develop policy for leasing. In addition to site characterisation, a detailed techno-economic evaluation of storage clusters would also be required. The UK case study detailed in Section 4 of the IEAGHG 2014 report demonstrates that targeting fewer, but larger, more geographically dispersed storage sites could meet future requirements as an alternative to clusters. Such large sites could provide enough storage capacity for multiple capture plants, and, in the USA, private pore space ownership may inhibit the development of clusters (if a lack of strategic policy occurs).

EOR sites have been identified as potential CCS resources but uncertainties arise for $CO_2$-EOR storage for various reasons. For ensuring net $CO_2$ emission reductions, an 'advanced $CO_2$-EOR' operation should be considered, where more $CO_2$ is stored permanently than the resulting operation and produced oil would emit. The economic viability of $CO_2$-EOR operations is a major issue as there are unknown cost-curves (cost of supplied $CO_2$ and future oil price fluctuations) and uncertainty with capital markets. Other uncertainties include the regulatory environments and public acceptance. EOR for the storage of $CO_2$ is an interesting and attainable strategy but would need much legal and regulatory management and policies that do not disincentivise existing commercial $CO_2$-EOR.

# 3 Improved Sweep Efficiency from the Oil and Gas Sector

Improving sweep efficiency in any injection project has been a popular topic during past decades. Much work has been done using water and $CO_2$ to enhance oil recovery, yet limited effort has been carried out to transfer these lessons to the $CO_2$ storage field. This study has undertaken a short literature review of some of the improved sweep efficiency technologies that have been considered for application in the geological storage of $CO_2$.

The main adding agents for improving sweep efficiencies in the oil and gas industry have been polymers, surfactants and foams and infill drilling.

1. Polymers: Commonly used as thickening agents to increase the viscosity of the formation fluid in the high permeable zones to redirect the injected fluid into the low permeable layers.
2. Surfactants: Used to change the interfacial tension between the injection and the formation fluid to reduce the residual saturation of the formation fluid.
3. Foams: Used to physically block the high permeable zones around the wellbore to redirect the injection fluid towards low permeable layers.
4. Infill drilling: Used to introduce new and different flow paths from injectors reaching parts of the reservoir that were previously unswept. Selective perforation within the injection interval and horizontal well geometries can also assist with this. As noted previously, this report does not go into details around wells and completion design.

Kim and Santamarina (2014), who undertook a study of engineered $CO_2$ injection, categorised four different methodologies to improve the sweep efficiency of $CO_2$ injection as follows:

1. Increased $CO_2$ viscosity and foams: Increasing viscosity can be achieved by using polymers (Alvarado and Manrique, 2010; Enick *et al*. 2010; Huh and Rossen, 2008). Whereas, foams enhance sweep efficiency by preferentially blocking the larger flow channels forcing $CO_2$ migration into smaller pores (Enick and Ammer, 1998; Farajzadeh *et al*. 2009).
2. Modifying the capillary factor: the most obvious strategy is to modify the $CO_2$–$H_2O$ interfacial tension using surfactants (da Rocha *et al*. 1999; Dickson *et al*. 2005; Ryoo *et al*. 2003; Stone *et al.* 2004).
3. Sequential fluid injection: Viscous fingering is lessened, and $CO_2$ displacement is enhanced by the intermediate injection of a fluid with density, viscosity, and wetting properties that are between the properties of brine and $CO_2$ (Alvarado and Manrique, 2010).
4. Bio-clogging: Preferential bio-clogging of the larger water-filled pores will cause flow to divert to low-permeability channels. Compiled results suggest that bio-clogging will be most effective most sediments (Rebata-Landa & Santamarina, 2012).

The effectiveness of foam injection for improving the efficiency of $CO_2$ displacement in $CO_2$ EOR has been performed in lab-based experiments on core (Casteel and Djabbarah, 1998). The core-flow experiments involved the simultaneous injection of $CO_2$ into two water flooded cores (Berea Sandstone). The cores were arranged in parallel and had different permeabilities. The test temperature and pressure were constant and above the critical conditions for $CO_2$. Three types of core-flow tests, involving injection of $CO_2$ to displace oil, injection of alternate slugs of $CO_2$ and brine, and injection of foaming agents, were conducted. The foaming agents were injected before $CO_2$ injection and after $CO_2$ had displaced oil from the more permeable core. The results show that in-situ foam generation is an effective method for improving $CO_2$ displacement efficiency. Foam was most effective when the foaming agent was injected after $CO_2$ displaced the oil from the more permeable core. The improved sweep efficiency was caused by the tendency of the foam to be generated preferentially in the more permeable core. The foam increased resistance to flow in this core and caused more $CO_2$ to flow through the less permeable core. Although the experiments were performed to assist EOR related projects, it can also be applied for $CO_2$ storage projects and the same experimental approach can be deployed to understand the impact of foam injection on $CO_2$ injection efficiency in CCS projects.

University of Texas Austin and Rice University developed innovative $CO_2$ foam concepts and injection schemes, based on core flooding experiments, for improving $CO_2$ sweep efficiency for both sandstone and carbonate formations (Nguyen *et al*. 2015). One of the important findings was that at very low fluid rates (i.e. far field rate conditions), the mobility of $CO_2$ in foam is quite uniform in both high and low permeability rocks. This indicates that in higher permeability zones foam is better for restricting the preferential flow of $CO_2$, resulting in higher sweep efficiency. For high flow rates (i.e. near wellbore rate conditions), the effective permeability of $CO_2$ increases with injection rates. Therefore, strong foam that reduces injectivity does not develop near the wellbore region. The core flood results are also useful for understanding local foam rheological behaviours and empirical approach-based foam modelling.

Hughes (2010) performed a study to evaluate the enhancement of $CO_2$ flooding. The project focused on relating laboratory, theoretical and simulation studies to actual field performance in a $CO_2$ flood to understand and mitigate problems of areal and vertical sweep efficiency. The work found that an understanding of vertical and areal heterogeneity is crucial for understanding sweep processes as well as understanding appropriate mitigation techniques to improve the sweep. Production and injection logs can provide some understanding of that heterogeneity when core data is not available. The cased-hole saturation logs developed in the project were also an important part of the evaluation of vertical heterogeneity. Evaluation of injection well/production (or monitoring) well connectivity through statistical or numerical techniques were found to be successful in evaluating $CO_2$ floods. Detailed simulation studies of pattern areas proved insightful both for doing a “post-mortem” analysis of the pilot area as well as a late-term, active portion of the Little Creek Field. This work also evaluated options for improving sweep in the current flood. The simulation study was successful due to the integration of a large amount of data supplied by the operator as well as collected through the course of the project. While most projects would not have the abundance of data, integration of the available data continues to be critical for both the design and evaluation stages of $CO_2$ floods.

Shamshiri and Jafarpour (2010) developed a new framework to optimise flooding sweep efficiency in geologic formations with heterogenous properties and demonstrate its application to waterflooding and geological $CO_2$ sequestration problems. The results from applying the proposed approach to optimization of geologic $CO_2$ storage problems illustrate the effectiveness of the algorithm in improving residual and solubility trapping by increasing the contact between available fresh brine and the injected $CO_2$ plume through a more uniform distribution of $CO_2$ in the aquifer.

Good vertical injection conformance is required for good sweep efficiency. If the $CO_2$ is not able to sweep all the layers, the overall storage capacity will diminish. Goyal et. al. (2017) introduced new high expansion ratio inflatable plugs to be applied in a polymer injection field. This is a mechanical solution that helped the operator to selectively produce from the poorly swept zones. A similar solution can be deployed in the case of $CO_2$ injection by isolating the zones which have been overly flooded and expose the injection stream to isolated zones.

Enick and Olson (2012) performed a literature review of the history and development of $CO_2$ mobility control and profile modification technologies in the hope that stimulating renewed interest in these chemical techniques will help to catalyse new efforts to overcome the geologic and process limitations such as poor sweep efficiency, unfavourable injectivity profiles, gravity override, early breakthrough, and viscous fingering. $CO_2$ mobility control technologies are in-depth, long-term processes that cause $CO_2$ to exhibit mobility comparable to oil. Profile modification and conformance control are achieved by a near-wellbore, short-term process primarily intended to greatly reduce the permeability of a thief zone.

The results of 40 years of research and field tests clearly indicate that mobility and conformance control for $CO_2$ EOR with thickeners, foams, and gels can be technically and economically attainable for some fields. Although the compiled literature review $CO_2$ EOR related, the suggested techniques can also be used in the geological $CO_2$ storage. The following technologies were recommended as results of their work:

1. $CO_2$ Viscosifiers (Direct Thickeners)
2. Near-Wellbore Conformance Control with $CO_2$ Foams and Gels
3. In-Depth Mobility Control $CO_2$ Foams

Another issue that sometimes reduces the efficiency of using the pore space is the existence of high permeability features, such as fissures, fractures and eroded-out zones. Placing crosslink conformance polymer gels or other types of blocking agents in injection wells might generate the required diversion agent. Crespo et. al. (2014) evaluated a high molecular weight organically crosslinked polymer gel system for such scenarios. Similarly, this has been tested for EOR projects and yet to be examined in $CO_2$ storage reservoirs where we only have two phases of $CO_2$ and brine.

Although the previous literature has primarily been IOR/EOR related, most of the techniques can be applicable for geological $CO_2$ storage in saline aquifers as well after being tested in laboratory scale or field trial projects.

# 4 Pressure Management

The displacement of native pore fluids during $CO_2$ injection operations causes an increase in the pore pressure in the region surrounding the wellbore. In sites where geological integrity is insufficiently understood, excessive pressure increases could initiate failure of the caprock and reactivation of existing faults, putting secure containment of $CO_2$ at risk. Removal of brine from a $CO_2$ storage reservoir, as a pressure management technology, has been investigated for several years as a mechanism to reduce the risk caused by pore pressure increases.

Pressure management can also play a role in optimising the storage efficiency of a $CO_2$ storage site. As mentioned in 1.3, the effect of dynamic capacity can be a limiting factor for $CO_2$ storage.

## 4.1 Background

This approach can be through the appropriate placement and operation of pressure relief wells to hinder the lateral spread of a plume in the up-dip direction, or less commonly considered by increased injection pressures to enable $CO_2$ flow into lower permeability paths.

In an appropriately characterised storage site, pressure thresholds, and associated uncertainties are well understood prior to an injection operation. Safe operations are designed so that pressure change is restricted below these thresholds to minimise the risk to geological integrity, meaning injectivity and storage capacity may need to be reduced.

The magnitude and lateral extent of this pressure increase is determined by several parameters including (but not limited to) porosity, permeability, thickness and extent of the reservoir, $CO_2$ injection rate, the number and placement of injection wells, any barriers to fluid flow, and any fluids extracted from the reservoir. Understanding the pore pressure distribution is essential to ensure optimal storage efficiency. Designing a safe and reliable monitoring concept with a clear purpose of discriminating pressure and saturation changes is crucial for maintenance of mechanical stability. Ensuring the long-term safety and conformance of the storage complex forms a fundamental prerequisite for an operators' CCS investment decision. Early detection of deviations from the expected response is desirable; a focus on monitoring pore pressure changes is likely to be more cost-effective than alternative monitoring surveys.

To maximise the storage efficiency, $CO_2$ must be optimally distributed within the reservoir. Local pressure build-up, or drop-off, offers an early warning of sub-optimal $CO_2$ flow and may indicate an elevated risk of leakage and/or fracturing, due to reservoir heterogeneities or near well issues. For example, the In-Salah $CO_2$ storage project in Algeria experienced reactivation of a fracture network partway through the lower section of a 950m thick seal because of injection pressure, and pre-existing fractures (White *et al*. 2013). Another example, the Snøhvit $CO_2$ injection into the Tubåen Formation, experienced rapid pressure increase, caused by salt precipitated in the near wellbore formation and a reduced the injectivity (Hansen *et al*. 2013).

The CCS industry highlights the requirement for intelligent reservoir management methods with emphasis on pore pressure control to enhance overall storage capacity (Nazarian *et al.* 2013). The importance of fluid pressure management in $CO_2$ storage has been emphasised in several publications, either through numerical simulations (e.g. Zhou and Birkholzer, 2011; Buscheck *et al.* 2012) or practical experiences (e.g. Eiken *et al.* 2011; Hansen *et al.* 2013).

## 4.2 Modelling

Numerical flow simulations have previously been used to investigate the impact of heterogeneity, and flow barriers such as faults and dykes, on a $CO_2$ storage operation. For example, the EU FP7 ULTimate$CO_2$ project studied the long-term behaviour of pressure in a storage reservoir using a regional geological model of the Bunter Sandstone (UK Southern North Sea). Additionally, the EPSRC-funded $CO_2$ Injection and Storage project investigated the impact of coupled brine production and $CO_2$ injection using numerical simulations of a homogeneous box model. Furthermore, studies such as Mbia *et al.* (2014) have modelled the pressure propagation due to $CO_2$ injection on specific case studies to investigate how overpressure is built up and dissipated. These studies have demonstrated how saturation and pressure can be controlled with water extraction in reasonably homogenous reservoirs. Additionally, studies on pre-injection brine production by Buscheck *et al.* (2016) have shown that the resulting pressure drawdown can provide direct information about possible overpressure effects during $CO_2$ storage and may provide operators with pre-injection information to optimise storage efficiency. Analytical and semi-analytical models of pressure build-up during $CO_2$ injection are available (Mathias *et al.* 2011; Mathias *et al.* 2009a, b; Szulczewski *et al.* 2014). These predict the magnitude and extent of overpressure due to $CO_2$ injection for little computational cost

Strategies involving the extraction of water from $CO_2$ reservoirs could be the primary method of interventional pressure management for $CO_2$ storage reservoirs. Extraction of water from $CO_2$ storage reservoirs acts to decrease the pressure and increase the available pore space. This results in a larger capacity and greater utilisation of the pore space for $CO_2$ storage (Bergmo *et al.* 2014). Simulation show that water production is becoming increasingly important as a pressure management tool for $CO_2$ storage, and the Gorgon $CO_2$ Injection Project will utilise four water production wells to manage pressure build up. Modelling studies have investigated numerous aspects of water production: limiting local pressure increase near $CO_2$ injection sites (Bergmo *et al.* 2011; Buscheck *et al.* 2012); reducing the pressure spatial footprint (Buscheck *et al.* 2011; Court *et al.* 2012); providing an intervention when site pressure exceeds design limits (Le Guenan and Rohmer, 2011); and targeting a specific area which might be especially vulnerable to increased pressure (Birkholzer *et al.* 2012). Pressure reduction is most effective in reservoirs with high permeability, weak heterogeneity and with water production close to the $CO_2$ injection. Storage sites within large open aquifers tend to require less interventional pressure management than more compartmentalised reservoirs since the connected pore volume acts as a buffer, absorbing pressure increases from $CO_2$ injection (Chadwick *et al.* 2009). Yet, whilst the primary effect of injection is often observed close to the wellbore, Cihan *et al.* (2013) observed that the potential large-scale displacement of saline formation water may affect a spatial domain that is orders of magnitude greater than the footprint of the fluid substitution.

**Pressure Relief**

There are two distinct categories of pressure relief through water production: active and passive.

**Active** water production involves the pumping of water from the reservoir through wells at a specified rate. This allows the rate of water production to be controlled from the surface independent of the reservoir pressure. Active water production may even commence before $CO_2$ injection (Buscheck *et al.* 2014) and it has been proposed that it can a be used to drive $CO_2$ into the reservoir (passive injection) avoiding the need of overpressure at the injection points (Dempsey *et al.* 2014).

**Passive** water production is a deliberate pressure management intervention which allows water to be extracted from the reservoir, driven by pressure increases above hydrostatic values (Bergmo *et al.* 2011). There are significant similarities with naturally occurring leakage through pathways such as open wellbores, fractures and faults (Birkholzer *et al.* 2011). One of the benefits of passive water production is that no pumping equipment or power is required on site. There is also no risk of a net depletion effect on the aquifer because the water production is driven by pressure increase. Both active and passive water production may release the produced water either into suitable shallower aquifers or at the surface.

**Increased Injection Pressure**

Increasing, in a controlled manner, injection pressure is also a pressure management technique to improve pore space utilisation through improved $CO_2$ sweep. To do this, it is important to understand how reservoir heterogeneity influences trapping. Low permeability zones in heterogeneous reservoir, even at small-scale, can have significant effects on large-scale pore space utilisation. Where injection can safely occur at higher pressures, $CO_2$ can be introduced into these zones. Exactly how small-scale heterogeneities affect the $CO_2$ injection and trapping processes is still being developed and a better understanding fluid processes and reservoir influence, from the field scale to the pore scale is required. Work already underway by the GeoCquest gives us confidence that this will be possible (Benson *et al*. 2018).

## 4.3 Real World Example

The use of water production adds to the costs of any $CO_2$ storage operation primarily through the operational costs of additional production wells, water pumping and water disposal (Breunig *et al.* 2013; Neal *et al.* 2011). In addition, particularly for onshore sites with brine production, questions occur regarding the disposal of the produced water either in overlying aquifers or at the surface (Bourcier *et al.* 2011). The Gorgon project, based on Barrow Island - 100 km off Western Australia, involves possibility of brine extraction through four water production sites (Flett *et al.* 2008; Liu *et al.* 2015) to control pressure. Injection planned to start in 2014 with injection of 3.4 Mt/year, and pressure management using brine production wells in a linear configuration some 4–5 km from the injection wells (Birkholzer *et al.* 2012).

In order to demonstrate safe storage of $CO_2$, operators must perform both direct pressure monitoring at injection and monitoring wells, and indirect monitoring and modelling of the $CO_2$ plume. Direct information from pressure monitoring is an indispensable prerequisite to calibrate reservoir models, from which the spatial extent of the plume can be predicted. Indirect monitoring methods targeted at tracking $CO_2$ plume movement and advancement of the pressure front (Strickland *et al.* 2014) include mostly seismic and non-seismic geophysical methods (e.g., electrical/EM, gravity, or wellbore logging) as $CO_2$ detection tools. At the Snøhvit $CO_2$ storage operation in the Barents Sea, offshore Norway, an overpressure phenomenon was observed during the initial phase of injection. White *et al.* (2015) and Grude *et al.* (2013; 2014) utilised 4D seismic data to differentiate between pressure and saturation changes generated during $CO_2$ injection. Eventually, the injection perforations in the wellbore were relocated to an overlying storage formation where $CO_2$ storage ran smoothly (Hermanrud *et al.* 2013).

Long-running projects, such as the Ketzin pilot and Sleipner show that as more data become available, the match between modelled behaviour and observations improves (Chadwick and Noy, 2015; Kempka and Kühn, 2013). Although these examples provide confidence that demonstration of conformance is achievable in a wide range of settings, more projects are required to gain confidence that a conformance workflow can routinely achieve a sufficient match between observations and models.

# 5 Microbubble $CO_2$ Injection

Microbubbles have various unique features, such as small size, low buoyancy and high solubility, in comparison with normal-size bubbles, and have been applied to diversified areas such as medical imaging, device cleaning, food processing and aquafarming. In the area of CCS, there have been several proposals of microbubble $CO_2$ injection to increase the $CO_2$ storage resource by increasing storage efficiency or by diversifying feasible reservoir types. Microbubble $CO_2$ injected together with water is thought to enter smaller pore space and mostly shrink and dissolve rapidly into formation water (Koide & Xue, 2009). In combination with the lower buoyancy of microbubbles, this approach can optimise the $CO_2$ storage in open structure reservoirs, fractured rocks and tight reservoirs. This would make source-sink matching and $CO_2$ storage for small-scale emission sources easier. In a case where microbubble $CO_2$ is dissolved into ground water extracted from an aquifer and then returned into the aquifer, the $CO_2$ reservoir could be located shallower than 800 m (Suzuki *et al*. 2013) Targeted $CO_2$ reservoirs are usually 800m or deeper to inject $CO_2$ in the supercritical state. Microbubble $CO_2$ could be also injected directly into an aquifer through a porous filter placed on borehole casing or gas tubing (Xue *et al*. 2014). The direct microbubble $CO_2$ injection could be also be applied to EOR to improve sweep efficiency.

## 5.1 Characteristics and Generation Methods

A microbubble is defined as a bubble with a diameter in a range from 1 $\mu$m to 100 $\mu$m (ISO/TC281). Microbubbles have higher solubility than normal-size bubbles in water. Microbubbles therefore rise slowly, shrink and ultimately disappear, whereas a normal bubble rises rapidly and bursts at the water surface. The characteristic is attributed to its larger interfacial area per volume, low buoyancy, and a higher inner pressure.

Microbubbles can be generated in several ways, including,

(1) Pressurised dissolution: Gas is dissolved into liquid under high pressure and then depressurised to generate supersaturation conditions, where the dissolved gas turns into microbubbles;
(2) Shear stress breakup: Microbubbles are generated through the separation from the gas stream in liquid by generating shear stresses conditions (e.g. mechanical vibration);
(3) Cavitation: Ultrasound waves are used to induce cavitation in gas-dissolved liquid, which generates microbubbles due to rapid reduction of pressure;
(4) Micropore: A microporous media is used to generate microbubbles in rapid flow or under high pressure.

## 5.2 Microbubbles $CO_2$ for CCS

To generate $CO_2$ microbubbles for geological $CO_2$ storage or $CO_2$-EOR, the required methods needs to maintain pressure, as well as being able to operate in subsurface conditions which can be high temperature and high salinity. In addition, a system that generates microbubbles needs to be easily installed, have high reliability, easily maintained and have an overall low operational cost. Research to date has targeted a micropore filter for microbubble $CO_2$ generation at the borehole casing or pressurised dissolution, and conducted lab tests with core samples to compare characteristics and behaviour of $CO_2$ microbubbles generated with the filter and those of larger $CO_2$ bubbles from the viewpoint of geological $CO_2$ storage and $CO_2$-EOR (Xue *et al*. 2014; Akai *et al*. 2015; Xue, 2016).

The micropore filter (shown in Figure 3a) demonstrated a capability of generating microbubble $CO_2$ in the gaseous (6 MPa and 40°C), liquid (10 MPa and 20°C) and supercritical (10 MPa and 40°C) phases. A quantitative analysis with serial images of supercritical $CO_2$ microbubbles (~50 to ~200 μm) and a larger supercritical $CO_2$ bubble (~400 μm) released in pure water concluded that the solubility of microbubbles is 20% higher than that of the larger bubble (Figure 3b).

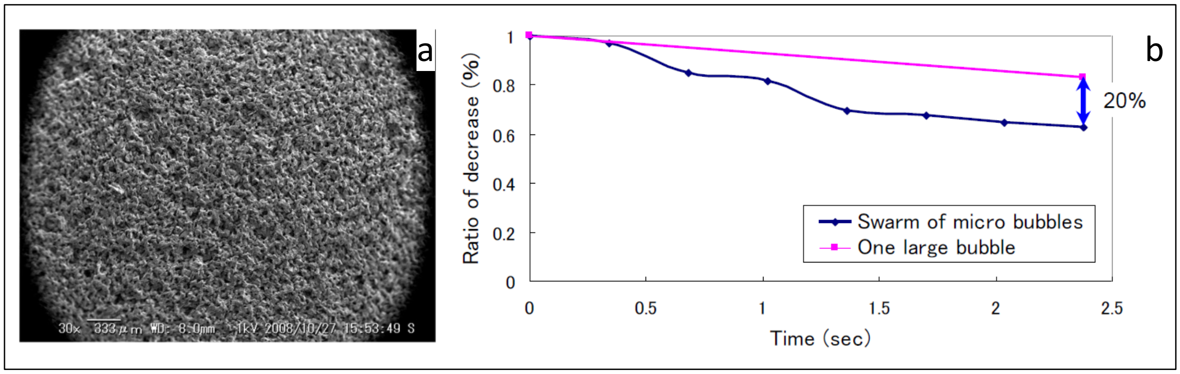


*Figure 3: A scanning electron microscopic (SEM) image of a porous plate; b) $CO_2$ bubble dissolution*

A series of two-phase lab tests with brine and $CO_2$ were conducted to simulate supercritical $CO_2$ injection for geological storage. In the tests, microbubble $CO_2$ and normal-size bubble $CO_2$ were injected at a rate of 0.05 ml/min into different brine-saturated Berea sandstone samples (70 mm long and 35 mm in diameter with the porosity of 18%) under conditions of a $CO_2$ reservoir (10.5 MPa and 40°C). The results show that microbubble $CO_2$ migrates more slowly, takes more time for breakthrough and shares more pore space than normal-size bubbles (Figure 4a). In Figure 4b, higher dissolution of microbubble $CO_2$ can be also observed at an early stage of injection. These results indicate that microbubble $CO_2$ injection has the potential of improving pore space utilisation.

The potential of microbubble $CO_2$ injection for higher pore space utilisation implies its potential of high sweep efficiency in a $CO_2$-EOR operation as well. To confirm the potential benefit, lab tests were conducted to simulate $CO_2$ injection for EOR with two 70 mm-long and 35 mm-diameter Berea sandstone core samples which have a similar porosity (18.5% and 17.5%). The cores were saturated initially with brine and then with oil (decane). Like the results of the two-phase tests previously shown, microbubble $CO_2$ migrated more slowly and sweeps more effectively than normal-size bubbles (Figure 5a). The microbubble $CO_2$ injection has 3% higher oil recovery rate (Figure 5b). The same test procedure was applied to core samples taken at a Japanese oilfield. In this case, microbubble injection presents clear advantage in oil recovery with > 10% higher rate than that for normal-size bubbles (Figure 6). The results imply that microbubble $CO_2$ injection has higher sweep efficiency in $CO_2$-EOR operation.

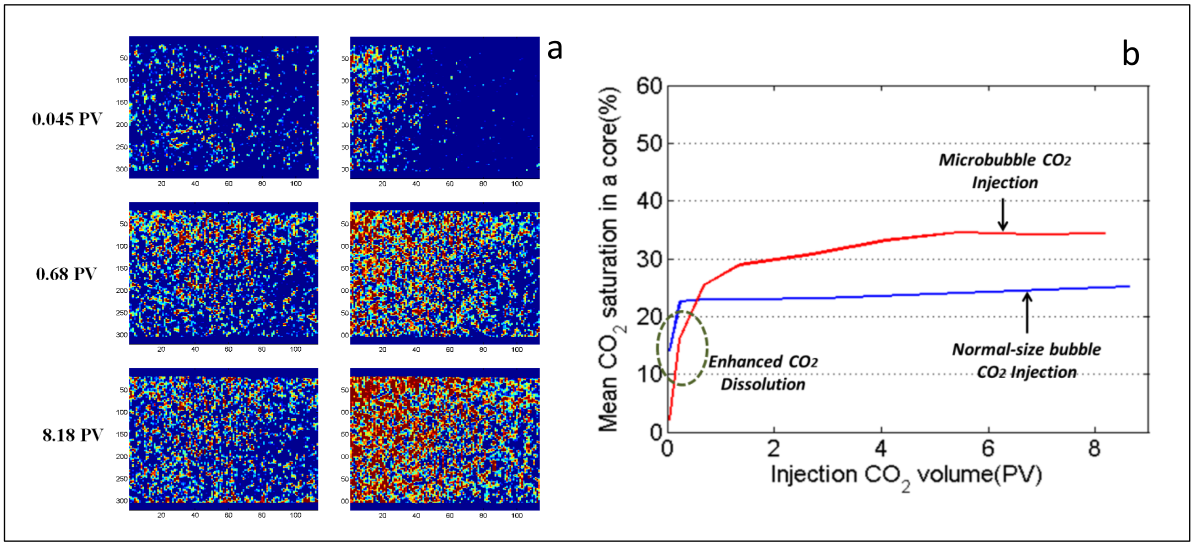


*Figure 4: a) X-ray CT images of Brine-Saturated Cores with $CO_2$ Injection (Right: Microbubble CO2 Injection; Left: Normal-size Bubble CO2 Injection); b) $CO_2$ Saturation in Cores (PV - pore space volume and 0.045PV means injection of $CO_2$ equivalent to 4.5% of PV)*

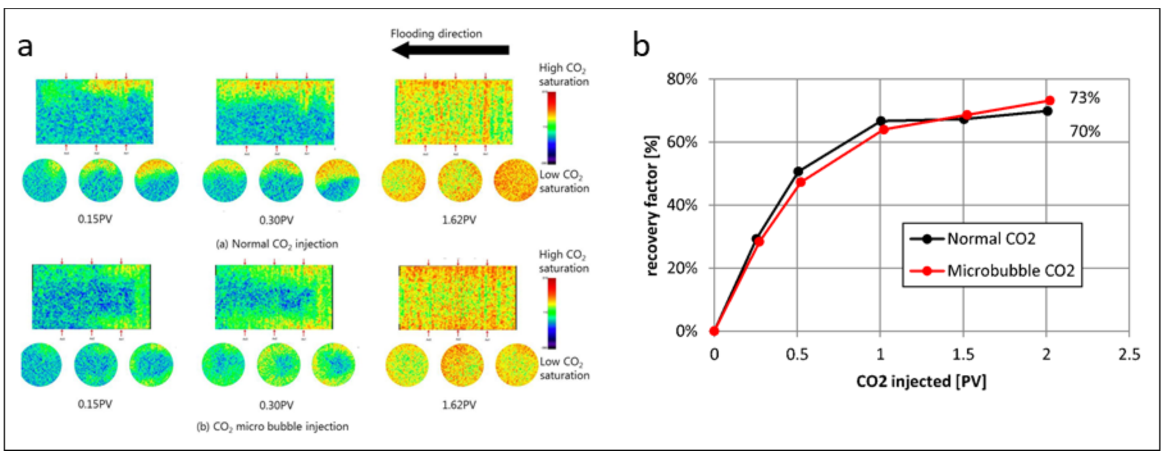


*Figure 5: a) X-ray CT images of Brine/Oil- Saturated Cores with $CO_2$ Injection; b) Oil Recovery – Berea Cores*

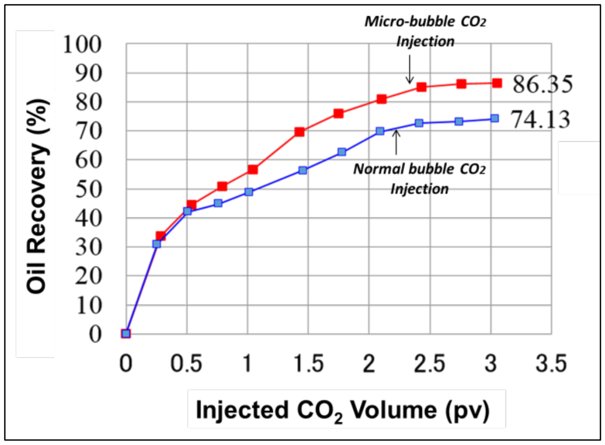


*Figure 6: Oil Recovery – Cores Taken at an Oilfield.*

Although further lab tests together with computational simulations are still required to make microbubble $CO_2$ injection technically available, field trials were initiated in Japan in 2018. A couple of prototype downhole tools for microbubble $CO_2$ injection equipped with the micropore filter were developed and tested in a 200m-deep well. With the most effective tool, microbubble $CO_2$ injection tests in a 900m-deep well are under planning to be initiated in 2019.

# 6 $CO_2$ Saturated Water Injection and Geothermal Energy Production

This chapter is a synthesis of literature by Blount *et al*. (2017), Blount *et al*. (2014), Galiègue & Laude (2017), Kervévan *et al*. (2016), Kervévan *et al*. (2013), Royer-Adnot & Le Gallo (2017). Complete references for this literature are found in 9 - References.

The $CO_2$ -DISSOLVED concept proposes an approach for targeting small-scale $CO_2$ emitters, combining CCS and the production of geothermal energy. This design combines capture, injection, and storage of dissolved $CO_2$ (rather than supercritical) in a deep saline aquifer with geothermal heat recovery. The $CO_2$ -DISSOLVED concept consists in coupling a patented $CO_2$ -brine dissolution technology to a geothermal loop with a hot brine production well for heat extraction and an injection well for re-injecting the cooled brine saturated with $CO_2$. This capture strategy makes it mandatory to use a water/brine movement provided by the geothermal facility.

The key feature of this innovative clean energy-CCS concept is the use of dissolved $CO_2$. The advantages of using a coupled system with no gas phase being present implies no pressure build-up effects, no displacement of the brine initially in place beyond the project footprint, and low leakage risk for the injected $CO_2$ to the surface**.** However, a physical limitation is the solubility of $CO_2$ in brine, which limits the rate and quantity of $CO_2$ injection in the aquifer. Consequently, the $CO_2$ -DISSOLVED concept is best suited for small-medium industrial $CO_2$ emitters and, as such, is complementary to the classical supercritical CCS more suited to high-rate emitters.

## 6.1 Technical Feasibility

This concept's main innovation comes from the capture technology that is selected (Blount *et al*. 2014). This technology is brought to the project by Partnering in Innovation, Inc. (a US company). The Pi-$CO_2$ capture method uses water as a physical solvent, circulating the water and emission gas through a cascade mass transfer system (MTS) located in a sealed deep large diameter well under ca. 25-60 bar hydrostatic pressure (Figure 7). The hydrostatic pressure significantly increases the solubility of gases in water. The system is closed loop with the high pressure non-dissolved separated gas fraction diverted to the surface and combined with heat to recover compression energy.

The flue gas is injected in the MTS at depth in the deep-water column. The gases ($CO_2$ and lesser competing gases) are concentrated through a cascading series of absorbers in the MTS. Water returning to the surface from the MTS becomes less pressured allowing for gas ex-solution, and this ex-solution drives the water circulation (gas lift pumping) so that additional energy and mechanical pumping are not needed for circulation. The non-$CO_2$ ex-solved gases are sequentially removed in the return line to produce near-pure $CO_2$. The system integrates compression and energy recovery processes at the surface to reduce parasitic load with heat exchange and turbo-machinery. Uniquely, the Pi-$CO_2$ process also removes SOx, NOx, vaporised metals, while capturing $CO_2$, in a single integrated process. The oxides are removed in compression condensate and at inter-cooler and after-cooler steps during flue gas compression (Blount *et al*. 2017). This in-process feature avoids expensive pre-treatment of the flue gas. Another interesting feature of the Pi-CO2 system is its expected easiness of construction since all the surface turbomachinery, heat exchange, and shaft installation equipment is currently available "off shelf". Moreover, as much of the installation is underground, the surface footprint is small.

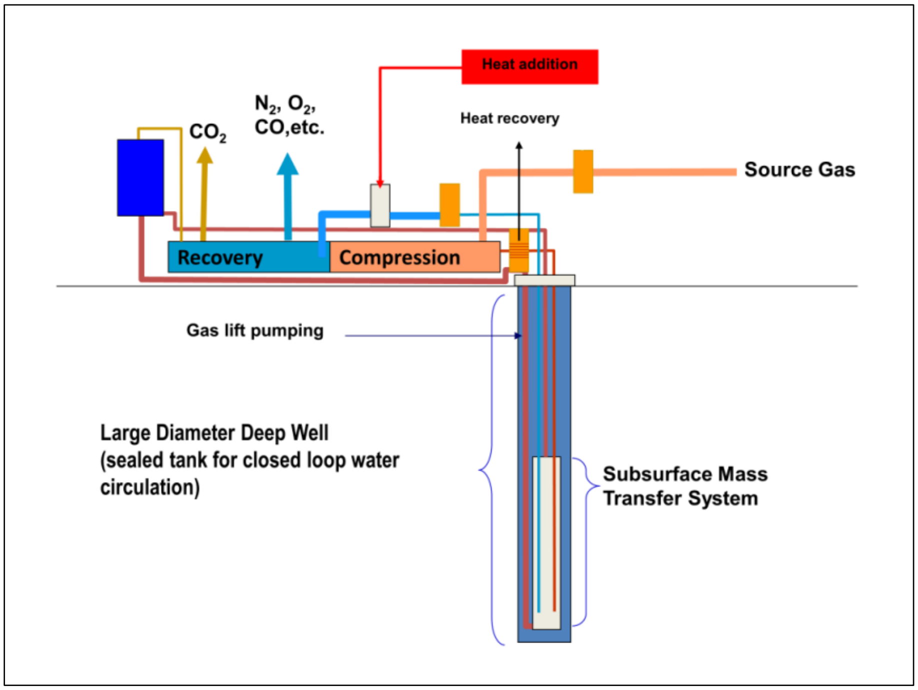


*Figure 7: Simplified view of the Pi-$CO_2$ water-based in-well capture technology planned to be used in a $CO_2$ -DISSOLVED system.*

The option of using a separated large-diameter well housing the Pi-$CO_2$ system and dedicated to the $CO_2$ capture operations was then considered (Figure 8). With this solution, this third well would be designed according to the actual needs in terms of $CO_2$ separation and injection, depending on the targeted flow-rate and on the flue gas composition. Once recovered at the surface, the separated $CO_2$ gas phase would then be injected in the doublet at a controlled mass-rate through a dedicated small-diameter pipe. This pipe would be ended at depth by a bubbler, specifically dimensioned to ensure complete $CO_2$ dissolution in brine before it reaches the storage aquifer. Mass transfer modelling proved the adequacy of such a system for easily dissolving several tens of kilotonnes of $CO_2$ per year. CFG Services (a BRGM subsidiary) confirmed that this system could be easily fitted in a standard geothermal injection well after a slight modification of the well head (equivalent to what is done for integrating an inhibitor injection line). An equivalent injection system for injection and dissolution at depth of $CO_2$ was successfully tested on the CarbFix site in Iceland.

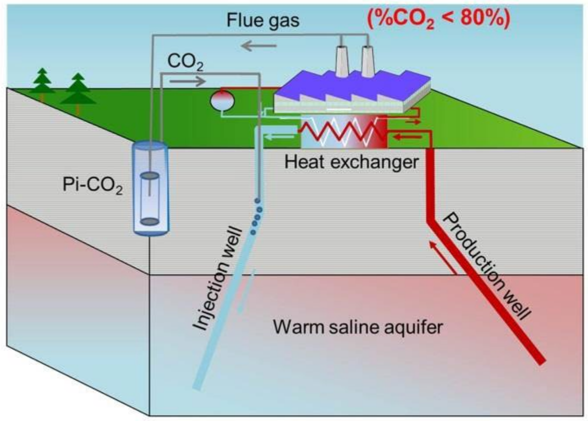


*Figure 8: Design of a $CO_2$ -DISSOLVED facility: standard version including the geothermal doublet and a third large-diameter well housing the Pi-$CO_2$ mass transfer system, when the $CO_2$ rate in the flue gas is lower than 80%.*

## 6.2 Applicability of the Concept

The technology applicability has been mapped at a country scale to potentially compatible sites. This was done by identifying and prioritising small rate industrial emitters (< 150,000 t per year of $CO_2$) that could potentially benefit from the application of this technology, to regions where reasonable geothermal resources occur. Three examples are presented hereafter: France, Germany, and the USA.

In France, the areas where the geothermal resources could potentially match the compatible industrial $CO_2$ emitters are composed by all the major sedimentary basins, i.e. the Paris Basin, the Aquitaine Basin, the Upper Rhine Graben, the Limagne and Bresse regions, and the Rhone corridor (blue and dark blue areas in Fig. 2). Then, 653 small to medium French emitters can be considered as potentially compatible with the $CO_2$-DISSOLVED concept (Figure 9). These 653 $CO_2$ sources have emitted a total amount of 25.1 Mt of $CO_2$ in 2011 (16.9% of the total French $CO_2$ emissions).

In Germany, the hydrothermal potential areas (proven or assumed) were considered for determining the potential areas of geothermal energy use. 242 small to medium emitters were located in favourable areas both for hydrothermal energy use and $CO_2$ storage. In total, these 242 $CO_2$ sources emitted 9.98 Mt of $CO_2$ in 2012 (7.1% of the total $CO_2$ emissions).

In the USA, the potential areas where the $CO_2$ storage could be coupled with geothermal activity are mostly concentrated in the western part of the USA, including Alaska and Hawaii. A few states along the east coast, including New York, Pennsylvania and West Virginia have low-temperature geothermal systems. Detailed information on the number of sources and emission totals for the small to medium emitters in the USA was not determined.

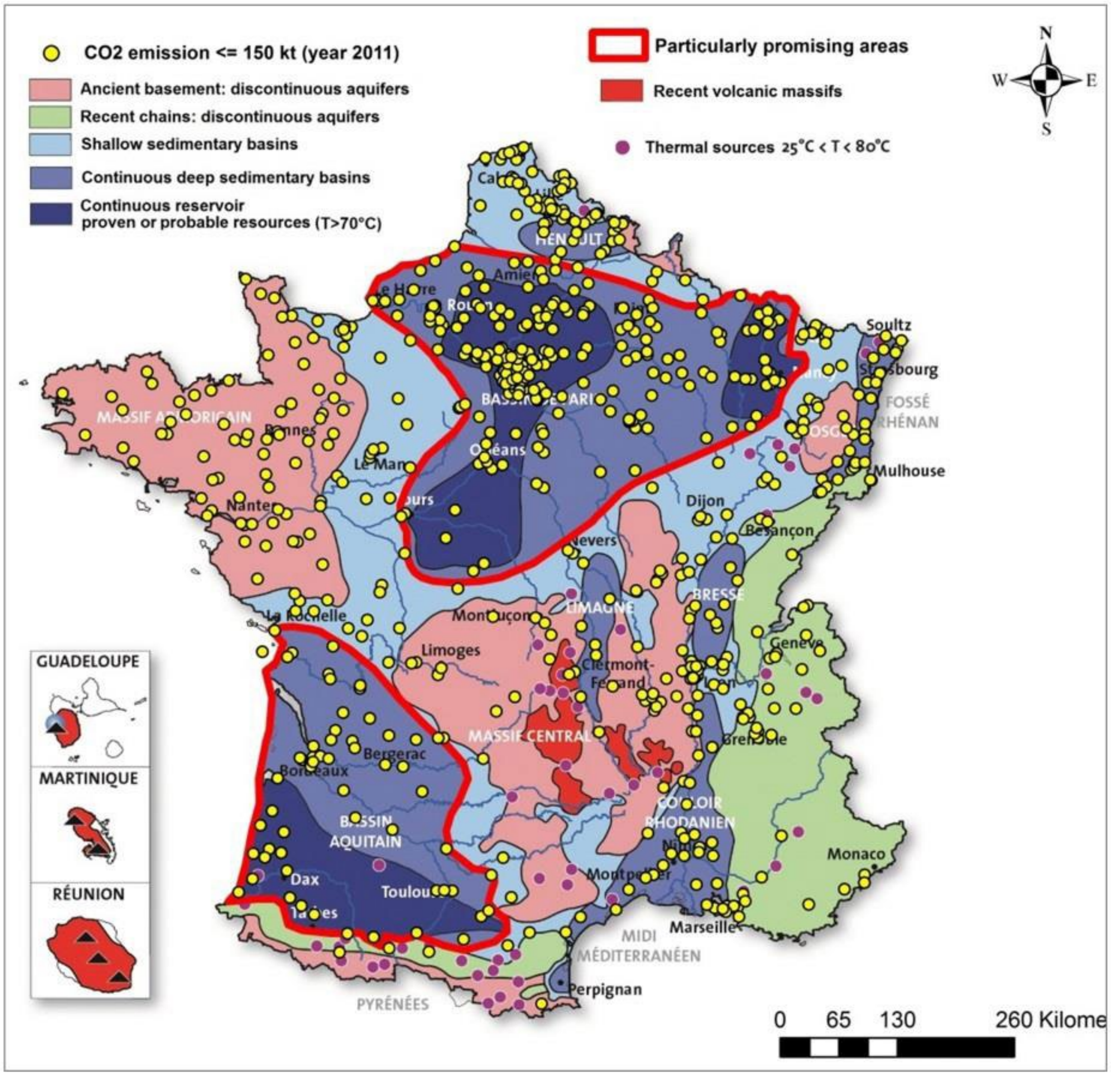


*Figure 9: Example of mapping small to medium $CO_2$ emitters (ca. 10-150 kt/yr, yellow spots) to geothermal resources.*

## 6.3 Economic Feasibility Study

To evaluate the $CO_2$-DISSOLVED concept, a preliminary economic analysis is performed based upon results from Laude *et al*. (2011) on a sugar beet refinery. The BECCS (Bio-Energy with CCS) approach (Fabbri *et al*. 2011) provides excellent environmental results with negative emissions due to the production of the bioethanol. However, on the economic standpoint, the performance of the project was poor due to the small volume of stored emissions that could not offset the required capital cost. Using the same base case plant, this paper presents the carbon and energy footprints and the economics of the $CO_2$-DISSOLVED concept. The work presented in this paper involves no specific process design and must therefore be considered as a conceptual study encompassing a significant level of uncertainty. Only the main equipment was considered based upon previous results which leads to uncertainties of more than 50%.

Based on a real case study, e.g. a sugar beet refinery, the $CO_2$ -DISSOLVED concept may reduce emission by 25% to 60% and energy consumption by 5 % to 30 % depending on the scenario.

Compared to the CCS case, the $CO_2$ -DISSOLVED concept showed an emission reduction from 15% to 50% while the corresponding non-renewable energy consumption was reduced by 5% to 30%. The $CO_2$ emission reduction is more important than the non-renewable energy consumption reduction due to compression energy requirements (even if compression power is reduced in the $CO_2$ -DISSOLVED case, the first stages of compression are consuming more energy).

However, the CAPEX requirement is reduced by 38 % to 47 % depending on the scenario considered. The cost per tonne of $CO_2$ avoided (stored + not emitted by the combustion due the use of geothermal energy) ranges from 39 to 72 $€_{2015}$/tonne avoided over 30-year project lifetime (at 6 % WACC). This is still higher than current $CO_2$ price level in Europe. However, with $CO_2$ price of 20 €/tonne throughout the project lifetime, the $CO_2$ -DISSOLVED concept has 60 % chance of being profitable in the low scenario while only 10 €/tonne is required for the High scenario.

If some revenues are claimed from $CO_2$ storage (currently not the case in the EU ETS framework for the $CO_2$ not issued from hydrocarbon combustion), the NPV of the $CO_2$ -DISSOLVED concept is better than the pure geothermal project.

This conceptual study shows that the $CO_2$ -DISSOLVED concept seems worth investigating for small $CO_2$ sources or partial capture of the emission. It may contribute to reduce $CO_2$ emission at significantly lower costs than CCS in the specific conditions including $CO_2$ availability and a favourable subsurface context (geothermal and storage).

## 6.4 Conclusion

$CO_2$ -DISSOLVED acts as a complementary technology to traditional CCS approaches and enlarges the potential of CCS for small or medium industrial emitters. This innovation enriches the portfolio of CCS combinations such as BECCS (BioEnergies and CCS). It helps then to overcome the current debates CCS versus renewable energies, showing a large gradient of situations. According to the Multi-Level Perspective (MLP) of sustainable transition, $CO_2$ -DISSOLVED could contribute to the transformation of the existing socio-technical system, and to its reconfiguration towards renewable sources of energy. As other competing technologies, it could play a rising role in the modification of the energy system. Then, focusing only on CCS implemented on large-scale emitters constitutes a narrow vision of CCS potential in the sustainable transition.

# 7 Swing Injection

To achieve increased storage capacity in reservoirs and better sweep efficiency, innovative compositional, temperature and pressure swing injection techniques have been developed. These patented methods have been simulated using Sleipner and Snøhvit-based reservoirs and the outcome of these studies show that increased storage and sweep efficiency, in addition to pressure control, can be obtained by applying these methods, in combination with intelligent well design, monitoring technologies and reservoir characterization (Nazarian, 2013 & 2014).

## 7.1 Concept Description

The idea behind Swing Injection Technology is to actively control the $CO_2$ plume behaviour, a technique called *Active Plume Management*.

Høier and Nazarian (2010) have developed three technologies, compositional, temperature and pressure swing injection, for stabilising the $CO_2$ injection front in a saline aquifer, which resembles WAG in hydrocarbon reservoirs. Swing injection technology allows plume control because more pore space is utilised for $CO_2$ storage and in the case of $CO_2$-EOR a better sweep efficiency is achieved (Figure 10). The injected $CO_2$ blend is designed to resemble cycles of liquid-like and gas-like injection.

By changing any of composition, temperature or pressure the thermodynamic equilibrium can be altered and by doing so the injected $CO_2$ phase can be used to obtain the desired gas or liquid like behaviour.

The gravity number describes the relative dominance of gravitational and viscous forces in the reservoir. It can be used to assess the expected behaviour of $CO_2$ injection in a saline formation by determining the extent of gravitational override. The swing injection technologies aim to reduce the gravity number during injection by increasing $CO_2$ viscosity and decreasing the density difference between brine and $CO_2$. This will result in a more centralised plume around the injection point and reduce the spreading and upward migration of the plume. To verify the proposed techniques, compositional and thermal models have been built based on realistic geological models of the Utsira Formation into which the $CO_2$ at Sleipner is injected.

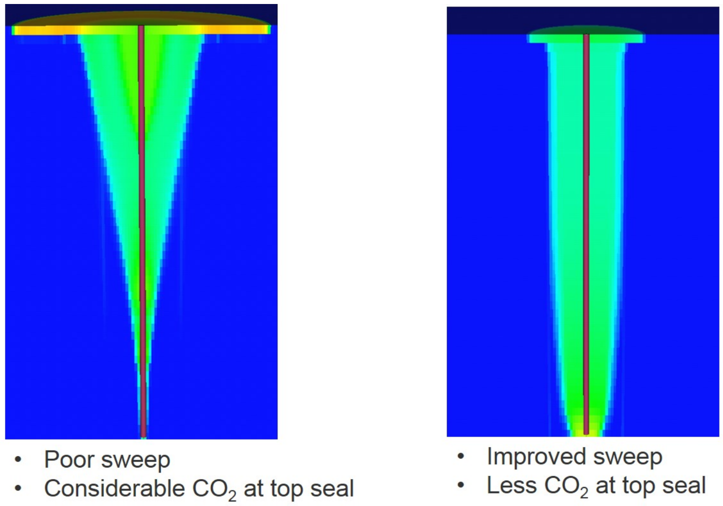


*Figure 10: Active plume management means to change the plume shape from the figure to the left to the figure to the right, which will maximize the storage capacity*

## 7.2 Compositional Swing Injection (CSI)

To alter a multi-component fluid system, the composition can either be changed by introducing an extra component or by changing the ratio of components in the system, resulting in a different critical point for the mixture. The effect of doing this can be quite substantial since the new mixture can exhibit totally different behaviour with respect to phase and mobility behaviour.

Introducing an extra component in the form of various hydrocarbon components, could be costly. To make the CSI method affordable it has been proposed to use $CO_2$ soluble polymers instead of hydrocarbons (Nazarian & Ringrose, 2014).

As an example of how CSI works, consider two different compositions A and B. Composition A represents a typical $CO_2$ rich injection stream and composition B is generated by changing the total composition (Nazarian *et al.* 2013). Composition A will exhibit gas-like behaviour under reservoir conditions whereas composition B will exhibit liquid-like behaviour (Figure 11).

The two compositions can be injected in cycles to create a gas-like slug chasing a liquid-like slug and thereby stabilising the front. Injection of composition A only would result in a “V-shape” type of plume. Cyclic injection of compositions A and B will result in a more “U-shaped” plume as shown in Figure 10 and thereby increase the utilised pore space.

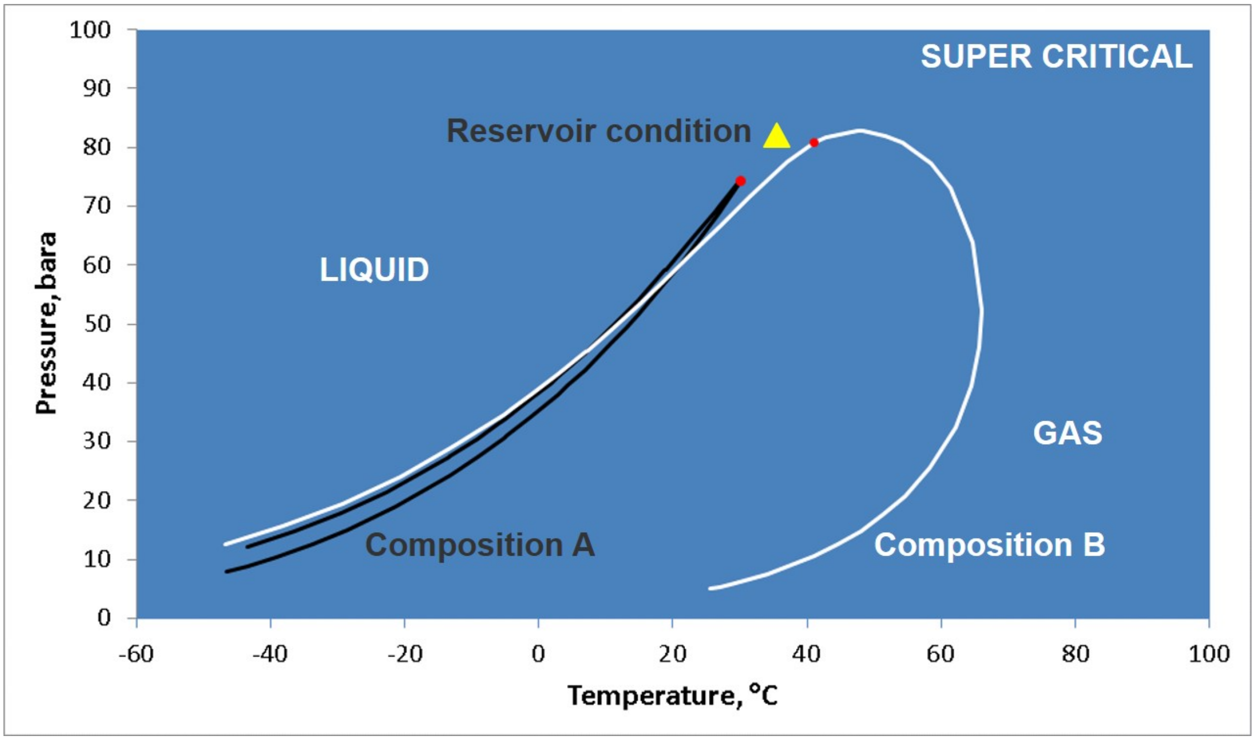


*Figure 11: Change of the total composition of the injected stream by adding a new component or by varying the mole fraction of existing components a liquid-like or gas-like behaviour can be achieved at reservoir condition. Composition A is a typical $CO_2$-rich stream. Composition B is generated by changing the total composition. As can be seen, the position of the critical point is changed. Consequently, while Composition A exhibits a gas-like behaviour under the given reservoir condition, Composition B exhibits a liquid-like behaviour.*

## 7.3 Temperature Swing Injection (TSI)

Temperature changes can also change the thermodynamic equilibrium in a multi-component mixture without changing the mixtures composition. As illustrated in Figure 12, a mixture will show liquid-like behaviour at 20 degrees Celsius, whereas the same mixture at a temperature of 60 degrees Celsius will show gas-like behaviour at the same pressure. The TSI injection concept involves cyclic injection of $CO_2$ streams at different initial temperatures to achieve the gas-like and liquid-like behaviour.

## 7.4 Pressure Swing Injection (PSI)

Altering the pressure of the injection stream will also cause a shift in the phase equilibrium as illustrated in Figure 13. Pressure change is, however, directly related to temperature and compositional variations. By changing the temperature, density variations of the injection stream will arise and result in a different hydrostatic head in the injection well, which also will result in a variation in injection pressure. Compositional changes of the injection stream will have a similar effect. The studies performed so far have only demonstrated the effect of TSI and CSI; however, PSI is assumed to have a similar effect (Nazarian *et al*. 2013). More likely, the effects could in practice be combined as a hybrid swing injection.

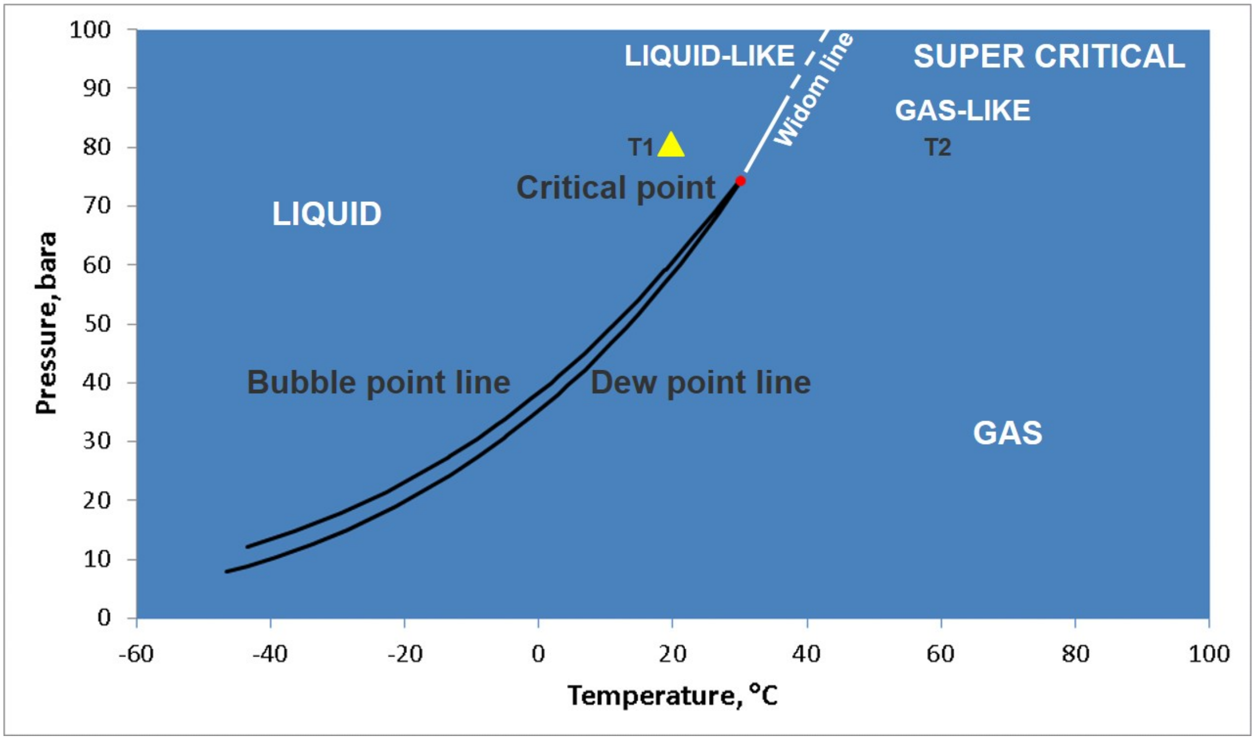


*Figure 12: Modification in properties can be achieved by cyclic change of the injection temperature. A typical injection stream demonstrates a liquid-like behaviour in state T1 and gas-like behaviour at state T2.*

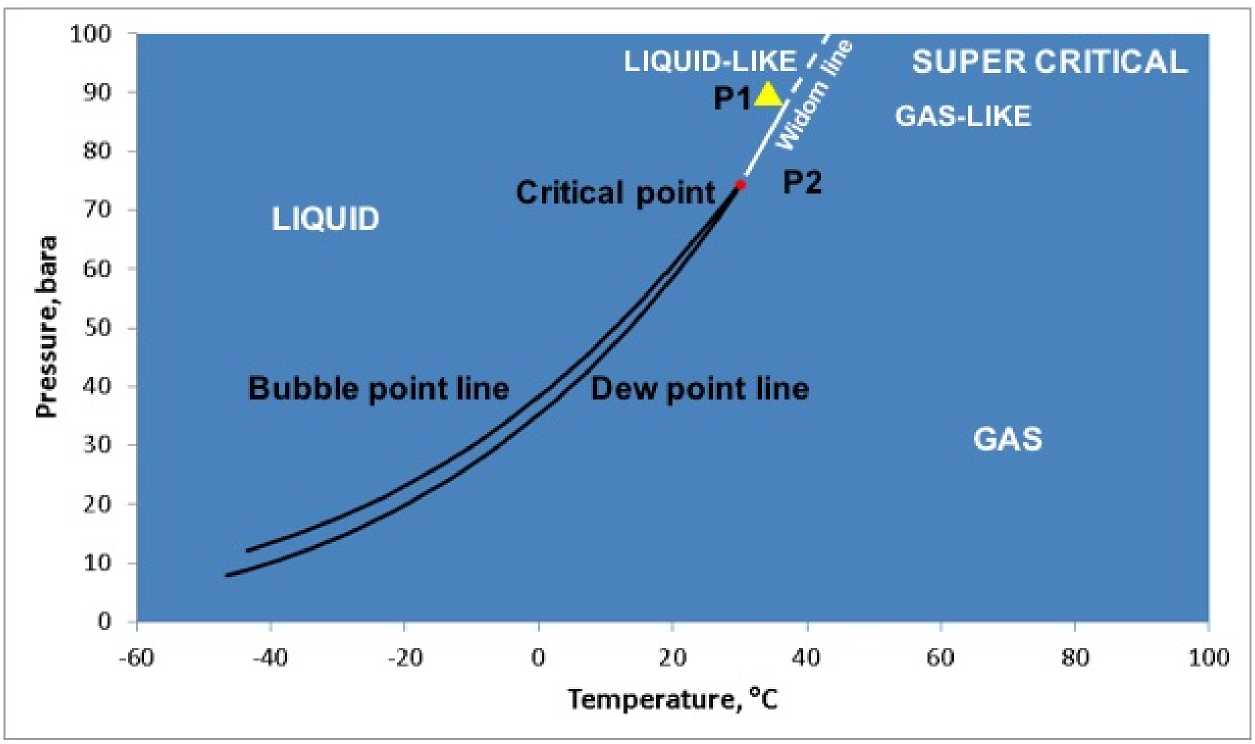


*Figure 13: For the same typical $CO_2$ composition, the injection pressure can be changed between states P1 and P2 so that the injected stream demonstrates liquid-like and gas-like behaviour at the injection point.*

## 7.5 Quantitative Analysis of Active Plume Management

As mentioned earlier, the effect of the CSI and TSI techniques can be described in terms of the gravity number, as shown in Table 2. Application of the CSI and TSI methods can reduce the gravity number by 33% and 35% respectively. However, temperature dissipation within the reservoir reduces the effect of TSI with respect to increased storage capacity (5%) compared to CSI, which increases storage capacity by around 62%.

*Table 2: The CSI technique results in around 30% reduction in gravity number. The volume of the reservoir cells touched by $CO_2$ will reduce by around 60%. TSI has the same effect on gravity number. This means that TSI can modify the properties of the injected stream.*

| Case | Gravity number $N_{gv}$ | Plume volume $Rm^3$ |
|---|---|---|
| Constant composition injection | $8.43 \times 10^{-3}$ | $9.52 \times 10^{10}$ |
| CSI technique | $5.64 \times 10^{-3}$ | $3.51 \times 10^{10}$ |
| Percent difference | 33.1 | 61.5 |
| Constant temperature injection | $7.21 \times 10^{-3}$ | $2.02 \times 10^{10}$ |
| TSI technique | $4.67 \times 10^{-3}$ | $1.92 \times 10^{10}$ |
| Percent difference | 35.2 | 5.0 |

Figure 14 illustrates these differences in plume behaviour based on the Sleipner model and comparing between injecting a $CO_2$-rich stream into the reservoir (Figure 14a) and the model where the CSI technique has been applied (Figure 14b). The injection rate is 1 Mt per year and duration is 30 years. In case A, with the $CO_2$-rich injection stream, a considerable amount of the $CO_2$ has reached the top seal and spread out, although some of the $CO_2$ is retained by intra-reservoir barriers. The plume which is generated after applying CSI is significantly different with an overall reduction in plume spreading both laterally and vertically.

It is also possible to combine the different parameters to obtain swing injection for a given situation. Combining the parameters can be used to minimise the magnitude of parameter modification for the controlling parameters.

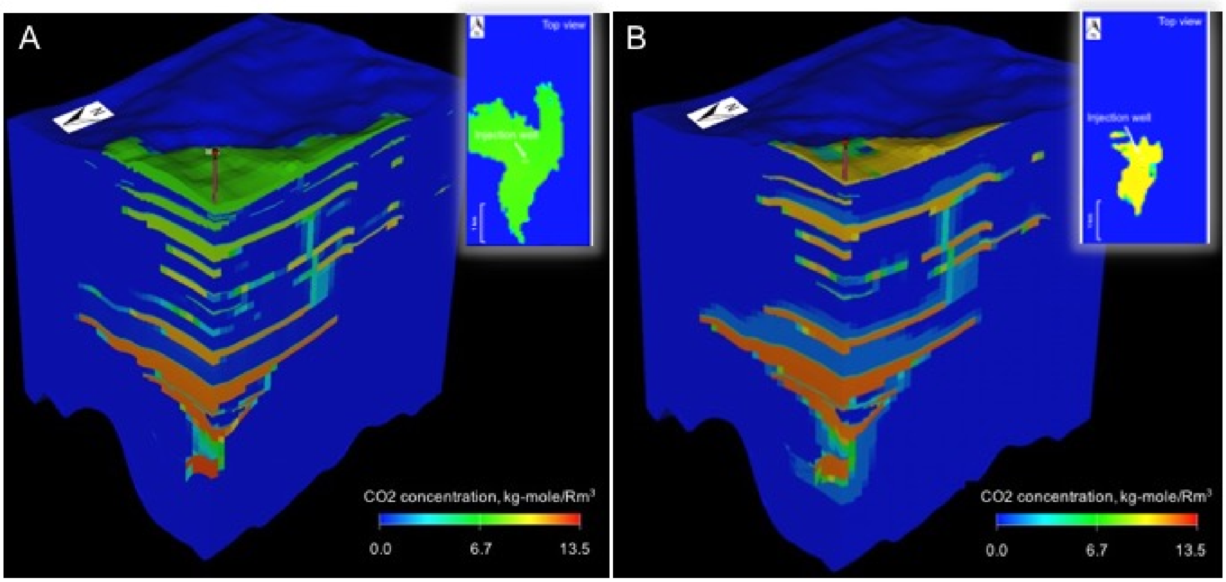


*Figure 14: Figure illustrating the difference between modelled behaviour of $CO_2$ injection with and without CSI technique.*

## 7.6 Well Design for Optimum Utilisation of Swing Injection Technologies

Well design plays an important role for maximising capacity in the reservoir. If injection takes place in a depleted oil or gas reservoir the $CO_2$ injectivity can be estimated from the production history of the field. If $CO_2$ is injected into a saline aquifer the reservoir properties are less well known and both injectivity and reservoir communication are much more uncertain. In such a situation, a standard vertical injection well cannot guarantee either the injectivity or the required pore space capacity. In industrial scale projects like Sleipner, Snøhvit or In Salah or demo projects like Ketzin and Decatur-Illinois, injection rates can be considered moderate. High injectivity and high pore space availability is crucial when new projects require high injection rates and capacity and under such circumstances vertical wells might not be the right solution.

Instead of using a vertical well, a *horizontal, multi-branch well* has been modelled using a reservoir resembling the Snøhvit Tubåen Formation (Nazarian *et al*. 2013). In this study, a horizontal well design has been shown to be a better alternative to a vertical well avoiding early pressure build-up and utilising more pore space. The aim of the study was not to control the vertical plume movement but to enhance injectivity.

# 8 Ranked Technique Effectiveness & Technique Status

With the growing challenge to rapidly ramp-up the volume of $CO_2$ storage to meet the 2,400 Mtpa target by 2035, all technologies are likely to represent strong value to the optimisation of site storage operations. All of the techniques examined have been considered from a TRL (Table 3). A summary of each technology is found in **Table 4**.

*Table 3: Technology Readiness Levels (TRLs) in the Project Lifecycle", Ministry of Defence website www.aof.*

| Technology Readiness Level | Description |
|---|---|
| TRL 1 | Basic principles observed and reported. |
| TRL 2 | Technology concept and/or application formulated. |
| TRL 3 | Analytical and experimental critical function and/or characteristic proof-of-concept |
| TRL 4 | Technology basic validation in a laboratory environment |
| TRL 5 | Technology basic validation in a relevant environment |
| TRL 6 | Technology model or prototype demonstration in a relevant environment |
| TRL 7 | Technology prototype demonstration in an operational environment |
| TRL 8 | Actual Technology completed and qualified through test and demonstration |
| TRL 9 | Actual Technology qualified through successful mission operations |

## 8.1 Polymers, Surfactants & Foams

Techniques from the hydrocarbon sector, focused on improved oil sweep in EOR operations, are reasonably mature, and are likely to only require some minor laboratory and modelling work specific to the use of $CO_2$ rather than water or methane as the injectant, before trialling in field. The effectiveness of these techniques would be highest near the injection well; how effectively these solutions apply far field (e.g. for a large saline aquifer) would need to be considered.

The use of these polymers and surfactants to access lower permeability zones and limit lateral spread does appear to strongly align to pore space utilisation in $CO_2$ storage. As these two technologies require additives to the injected volume of $CO_2$, a cost analysis would be needed relative to the 10s of Mt of $CO_2$ being injected.

Foams, having a nearer wellbore effect than polymers and surfactants, may be a cheaper option to consider. The application of foams block high permeability pathways, thus preventing long fingering of $CO_2$ and creating large regions for monitoring. However, this application removes access to some of the pore space. Further investigations are therefore recommended to consider the best way to use this technique.

## 8.2 Pressure Management

Pressure management has, because of hydrocarbon production and EOR operations, been tested at commercial scale. However, this application has not been performed in $CO_2$ storage activities, either as a risk reduction technique or for the purposes of optimising the use of pore space. Pressure relief wells are being considered for future CCS projects, and active pressure relief has been included as part of the operation for the Gorgon $CO_2$ Storage Project. It will become important to gain learning from this project, as well as the broader application of pressure relief for the purposes of pore space optimisation.

Understanding the behaviour of stored $CO_2$ in heterogeneous reservoirs will be key to testing the effectiveness of increased injection pressure for improving $CO_2$ sweep. Given that the essentially all reservoirs are heterogeneous to a degree, it is important to gain a detailed understanding of capillary processes during $CO_2$ injection and plume migration. The approach adopted by the GeoCquest project is a good example of the type of activity required to then consider how to enhance pore space utilization, with their ultimate aim is to apply their workflow at a commercial scale site that typically will be in a heterogeneous sandstone. Their investigations to date suggest that rock heterogeneity at all scales enhances trapping.

## 8.3 Microbubble $CO_2$ Injection

The concept of microbubble $CO_2$ injection for higher pore space utilisation shows very high potential to high sweep efficiency in both direct $CO_2$ storage operations and in a $CO_2$-EOR operation. Laboratory analysis already conducted has shown the potential benefit on Berea sandstone and Japanese oil field core samples, and modelling results show microbubble $CO_2$ migrating more slowly and with improved spread relative to normal-size bubbles. Further, this technique shows a rapid level of dissolution of the $CO_2$, which utilises the existing formation fluids more effectively and improves the long-term containment of the injected $CO_2$.

This technique, validated in models and laboratory, needs to be trialled at a field scale.

## 8.4 $CO_2$ Saturated Water Injection and Geothermal Energy Production

The use of pre-dissolved $CO_2$ provides a good example of pairing a complementary technology to traditional CCS approaches, to apply the use of CCS for small or medium industrial emitters.

This technique would have niche opportunities in the improved pore space utilisation area yet can help enable the ramp up of CCS by its complementary technology nature. For this technique to be considered commercially, the PI-$CO_2$ technology at lab scale would require trial at a field scale.

## 8.5 Swing Injection

Swing injection through changing the composition, temperature and/or pressure allows the thermodynamic equilibrium to be altered so that injected $CO_2$ can have modified flow properties. With changes in these properties resulting in reduced buoyancy, improved sweep and limited lateral spread, they present strong candidates for improving a $CO_2$ storage operation's pore space utilisation.

The described technology has been through the modelling stages and is at present considered to be at TRL 3.

*Table 4: Comparison table of pore space utilisation technologies. Technologies are ranked in order of priority (column 'P') for continued technology maturation. Green indicates high perspectivity for the technology, light green less urgency, while orange indicates lower technology prospectively broadly, yet strong niche opportunity.*

| P | Technology Type | Prior R&D and application | Technology Readiness Level (TRL)# | Technology Prospectively | Core Recommended Action |
|---|---|---|---|---|---|
| 1 | Microbubble $CO_2$ Injection | Laboratory and Modelled, prototype | TRL 4 | High potential | Trial at in field research facility |
| 2 | Swing Injection | Laboratory and Modelled | TRL 3 | High potential | Validate technology at lab scale |
| 3 | Increased Injection Pressure | Laboratory and Modelled | TRL 3 | High potential | Validate technology at lab scale to assess sweep effectiveness in heterogeneous reservoirs |
| 4 | Active Pressure Relief (increase sweep & reduce lateral spread) | EOR, planned for Gorgon $CO_2$ injection project | TRL 6 | High potential | Pressure relief - Key lessons drawn from active commercial project using pressure relief wells as a risk mitigation technique |
| 5 | Foams (block high permeability pathways) | EOR | TRL 6 | Reasonably well understood | Modelling of application effectiveness prior to Demonstration at commercial scale |
| 6 | Passive Pressure Relief | Modelled | TRL 4 | Limited effectiveness | Trial at field research facility. Consideration around long-term fluid management |
| 7 | Polymers (increase formation water viscosity) | EOR | TRL 7 | Reasonably well understood | Cost effectiveness investigations. Demonstration at commercial scale* |
| 8 | Surfactants (reduce residual saturation of formation water) | EOR | TRL 7 | Reasonably well understood | |
| 9 | $CO_2$ saturated water injection & geothermal energy | Laboratory and Modelled | TRL 3 | Site specific & lower volume | Seek opportunity to trial PI-$CO_2$ technology at lab scale |

* minor modelling and laboratory investigations may be required prior to commercial scale application
# See technology readiness chart

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## 9.1 Glossary of terms

| Term | Definition |
|---|---|
| **°C** | Degrees Celcius |
| **BECCS** | Bio Energy and CCS |
| **$CO_2$-EOR** | $CO_2$ Based Enhanced Oil Recovery |
| **CSI** | Compositional Swing Injection |
| **CT** | Catscan |
| **EM** | Electromagnetic |
| **EOR** | Enhanced Oil Recovery |
| **FCFS** | First Come, First Serve |
| **IOR** | Improved Oil Recovery |
| **ISO** | International Organisation for Standardisation |
| **MLP** | Multi-Level Perspective |
| **μm** | Micrometre (1/1,000,000 metres) |
| **Mpa** | Mega Pascal |
| **Mt** | Million Tonne |
| **MTS** | Mass Transfer System |
| **NPV** | Net Present Value |
| **PSI** | Pressure Swing Injection |
| **PV** | Pore Space Volume |
| **R&D** | Research and Development |
| **SEM** | Scanning Electron Microscope |
| **t** | Tonne |
| **TRL** | Technology Readiness Level |
| **TSI** | Temperature Swing Injection |
| **UGS** | Underground Storage |
| **WACC** | Weighted Average Cost of Capital |